YUKON ENERGY CORPORATION

2023-24 GENERAL RATE APPLICATION

AUGUST 2023

2023-24 GENERAL RATE APPLICATION

TO THE YUKON UTILITIES BOARD (BOARD)

YUKON ENERGY CORPORATION

INTRODUCTION TO APPLICATION

Yukon Energy Corporation's (Yukon Energy or YEC) 2023/24 General Rate Application (the GRA or Application) addresses changes to Yukon Energy's approved revenue requirement and other matters through implementation of an adjusted Rider J[1] in order to meet Yukon's need for an increasing supply of safe, reliable and sustainable electricity.

Pursuant to the Order in Council (OIC) 1995/90 direction (as amended by OIC 2018/220), the Yukon Utilities Board (the Board or YUB) must ensure that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers. Consequently, all proposed 2023 and 2024 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

Proposed Approach

As part of this Application, YEC is seeking the YUB's support to approve the timing for implementation of YEC's interim rate increases and final rate adjustment to occur when other charges on electricity bills are

[1] Ride J is applicable to all firm retail customer class rates and to firm major industrial customer class rates.

expected to be reduced and/or expire. Through this approach, the impact of YEC's 2023 and 2024 rate increases on customer bills will be reduced, there would be no impact to residential bills throughout the winter, and greater bill stability and predictability will be provided to Yukoners. The proposed approach includes three dates for rate adjustments:

- Interim rate change October 1, 2023 to correspond with AEY's requested interim rate reduction;
- Interim rate January 1, 2024 to correspond with the expected removal of the Rider F charge; and
- Final rate and true up rider August 1, 2024 to correspond with removal of YECs 2021 GRA true up rider.

As summarized in Table 1 below, YEC's proposed total average rate increase is 14.11%. With proposed rate changes timed to coincide with removal/ expiry of other charges, this rate increase will equate to a 6.1% bill increase for residential customers using 1,000 kWh/ month, and 6.6% bill increase for commercial customers using 3,500 kWh/month.

Table 1: Proposed Rate Changes and Expected Bill Impacts [excl. AEY 2023/24 GRA impacts]

Proposed Date of Rate Adjustment	Rate increase	Residential bill increase [1,000 kWh/month]	Commercial bill increase [3,500 kWh/month]
October 1, 2023	3.34%	3.0%	3.0%
January 1, 2024	8.44%	0.0%	0.4%
August 1, 2024	2.33%	3.0%	3.0%
Total:	14.11%	6.1%	6.6%

Factors Driving the 2023-2024 Revenue Shortfall

The cumulative rate increase of 14.11% is required to recover a $6.667 million revenue shortfall in 2023 and a $15.320 million shortfall in 2024. This revenue shortfall reflects the extent to which existing rates are unable to fund YEC's forecast costs including its debt and equity costs needed to sustain its investments.

As detailed in Tab 1 of the Application, significant and timely investments in all aspects of the Yukon's electricity system – generation, transmission, distribution, storage and grid stability, and end-use – are needed now. The factors driving the need for YEC's proposed rates include: (i) steady growth in peak electricity demand, (ii) the need to upgrade or replace aging generation, transmission and distribution infrastructure, (iii) transition from reliance on fossil fuels in Yukon's heating and transportation sectors to clean energy alternatives, and (iv) the impact of rising costs and project complexity.

- **Growth in winter peak electricity demand:** Yukon is experiencing faster growth than any other province or territory in Canada. Between 2016 and 2021, the Yukon's population increased by 12%, much higher compared to any other province/territory [Canada's average was 5.2%]. This population growth, along with growth in our economy and the move to electrify the territory's heating and transportation sectors, is causing an increase in annual peak demands for power. For example, every home that converts from a propane or diesel heating source to electric heat requires four times the amount of electricity as before.

  The Yukon's peak demand for electricity has increased by 23% in the last five years [from 2017 to 2022] and this trend is expected to continue with an additional 36% increase in non-industrial peak by 2030. Meeting these peaks demands for power in the short term requires the rental and operation of diesel generators each winter until new sources of dependable capacity can be built or connected to the Yukon grid. As more Yukoners begin using electricity for heat, the security provided by these rental units is more significant than ever before to ensure a reliable supply of the electricity needed to keep Yukoners' homes warm and safe during the winter months.

- **Aging infrastructure**: Built primarily in the 1950s and 60s, much of the Yukon's electricity system is nearing end-of-life and needs significant upgrades or to be replaced. At the same time, water licences for each of our three hydro facilities and permits for many of our thermal facilities will need to be renewed – all within the next five years. Upgrading and replacing existing electricity assets, while at the same time renewing licences and permits for YEC's existing generation facilities, is critical to ensuring YEC's ability to continue to provide Yukoners with the electricity they need today while building and connecting the new sources of electricity needed in the future.

- **Energy transition:** Yukon's electricity system is in a state of transformation with rapid changes to the way Yukoners both consume and produce electricity. As governments pursue targets to lower greenhouse gas emissions locally and nationally, they turn to electricity as a cleaner alternative to fossil fuels used in the heating and transportation sectors. End-users are being incentivized to make the switch to electric heat and modes of transportation, as well as to distributed sources of electricity generation. These changes in end-user behaviour put increased pressure and strain on the electricity system and require significant and urgent investments in all aspects of the Yukon's electricity system. Supporting these climate objectives requires significant and urgent investments in all aspects of Yukon's electricity system. These include generation, transmission, distribution, storage and grid stability and end-use programs to bolster the capacity of the Yukon's generation, transmission and distribution resources now and in the future. Investments in smart programs and technologies, including demand-side management (DSM) programs, are also needed to better manage and shift system peaks when products like electric vehicle chargers, electric baseboards and water heaters, and heat pumps are used.

- **Rising costs and project complexity:** Like other businesses in Yukon, YEC is not immune to external pressures like inflation, increased labour costs, and the supply chain delays and constraints experienced in recent years. Completing projects in the right way is also more complex now than before requiring more time and resources to lead years of planning and collaboration with rightsholders and multiple stakeholders to ensure project success. More resources are required to direct, plan, execute and oversee the way Yukon Energy does business, to meet the needs of larger projects both in terms of project scope and expenditure, more projects to connect new customer extensions and distributed energy sources to the grid, and greater stakeholder expectations and involvement in the way our work is done.

These pressures reflect our new reality: a changing world with changing demands for how Yukoners use and produce electricity. This future will depend on a more complex electrical system, one that will require significant generation, transmission and distribution system upgrades to support electrification.

Meaningful reconciliation with First Nation governments and citizens, and their involvement in the energy sector, will also be critically important to this future. Direct participation by First Nations in new and existing projects and the energy transition will greatly facilitate important reconciliation efforts in communities while supporting electrification, grid modernization and climate change objectives.

As the primary generator and transmitter of electricity in Yukon, it is YEC's responsibility to lead these changes. On an isolated grid, these investments are even more paramount. YEC cannot import electricity when needed or export power to other jurisdictions when there is a surplus. For YEC and Yukoners, this means we only have ourselves to rely on to ensure there is enough capacity to reliably generate the electricity Yukoners need now and in the future.

Rate increases in Yukon are needed over the next five to ten years to make investments to meet our growing demands for electricity. They are needed:

- To begin the transition to electrification;

- To build and connect the critical projects that will provide Yukoners with an adequate supply of safe, reliable and sustainable electricity to fuel their homes, lives and businesses;

- To make the electricity system resilient to climate change and to make repairs in the aftermath of climate events;

- To make upgrades throughout the system to ensure we maintain stability and reliability while providing consumers with greater flexibility; and

- To recover the costs of doing business in a better way.

Proposed Rider J to Address 2023 and 2024 Revenue Shortfall

The current level of firm rates result in a $6.667 million rate revenue shortfall in 2023 and $15.320 million shortfall in 2024 compared to revenue requirements set out in Tab 3. This shortfall, outlined in Table 2 below, forms the basis for the proposed rate increases in this Application.

Table 2:
Yukon Energy Revenue Required from Rates ($000s)

	2023	**2024**
Revenue Requirement	$81,440	$90,425
Less: Other Revenues	$394	$394
Less: Secondary Sales	$358	$358
Revenue Required from Firm Rates	$80,688	$89,673
Less: Revenues from Firm Sales at Existing Rates [includes Rider J]	$74,021	$74,353
Additional Firm Rate Revenues Required	$6,667	$15,320

In accordance with OIC 1995/90 direction, the Application proposes that the Yukon Energy revenue shortfall for the test years be recovered through a Rider J increase of 8.99% in 2023 and a further 11.21% in 2024 applicable to all YEC and AEY retail firm rates and all major industrial firm rates. The GRA Application is seeking interim refundable Rider J rate increases of 4.80% for retail and industrial customers effective October 1, 2023; and a further interim refundable Rider J rate increase of 12.02% effective January 1, 2024. Yukon Energy is seeking final rates effective August 1, 2024.

SUMMARY OF REQUESTED ORDERS

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

1. **2023 & 2024 Revenue Requirement:** Approval of the forecast revenue requirement of $81.440 million for 2023 and $90.425 million for 2024, 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 $16.272 million in 2023 and $16.967 million in 2024, including approval for the following related matters:

        i. **Adjusted Fuel Prices:** Approval to adjust delivered diesel and LNG prices used in setting average fuel costs per kW.h to be $0.3069/kW.h for diesel and $0.1906/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.

    b. **Non-Fuel Operating and Maintenance Costs:** Non-fuel operating and maintenance costs forecast of $34.999 million in 2023 and $37.484 million in 2024.

        i. **IPP Purchase Cost Deferral Account**: YEC is requesting approval of IPP Purchase Cost Deferral Account that captures variances in IPP purchase costs included in the test year revenue requirements and actual purchase costs offset by IPP LTA thermal displacement benefits calculated as per above example using 59% LTA thermal displacement benefits.

    c. **Depreciation and Amortization Expenses:** Approval of depreciation and amortization expenses forecast of $11.997 million for 2023 and $15.161 million for 2024.

    d. **Mid-Year 2021 Forecast Rate Base:** Approval of mid-year forecast rate base costs of $332.396 million for 2023 and $376.004 million for 2024, including costs for capital works and deferred cost projects brought into service (or forecast to be brought into service) since the 2021 General Rate Application.

    e. **Return on Rate Base:** Approval of $18.172 million in 2023 and $20.814 million in 2024 including an allowed rate of return on equity of 8.70% for both test years.

2. **2023 and 2024 Rates:** Approval of the following rates to recover the 2023 and 2024 revenue shortfall:

    a. **Interim Refundable Rates effective October 1, 2023:** Approval to implement an interim refundable rate rider increase (Rider J) of 4.80% for retail firm rates and industrial firm rates effective on an interim refundable basis as at October 1, 2023 (see Tab 4, Appendix 4.1A for proposed interim Rider J rate schedule).

    b. **Interim Refundable Rates effective January 1, 2024:** Approval to implement an interim refundable rate rider increase (Rider J) of 12.02% for retail firm rates and industrial firm rates effective on an interim refundable basis as at January 1, 2024 (see Tab 4, Appendix 4.1B for proposed interim Rider J rate schedule).

       VGC Group and Alexco Fixed Charge: Approval to implement an interim refundable Fixed Charge for VGC Group of $46,554.84/month and for Hecla Yukon (previously Alexco) of $21,295.74/month effective January 1, 2024.

       Following receipt of final orders in this proceeding, including a final 2023 and 2024 revenue requirement, any residual shortfall or surplus will be addressed pursuant to direction of the Board.

    c. **Approval of final 2023/24 Rates:** Effective August 1, 2024 when the 2021 GRA true-up rider expires.

OVERVIEW OF SUPPORTING DOCUMENTS

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 2021 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 2023 and 2024 test years.

- **Tab 3 Revenue Requirement:** Provides detailed information on Yukon Energy's total forecast cost of providing service in 2023 and 2024 test years, 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 from 2021 to 2024 years. This tab also provides detailed business cases for the capital projects undertaken and forecast for the test years.

- **Tab 6 Board Directives:** Provides a review of past Board Orders and responses to outstanding directives since the 2021 GRA.

- **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 2023 and 2024 test years.

- **Tab 9 Audited Financial Statements:** Provides a copy of Yukon Energy's audited financial statements for 2022.

- **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.

SUPPORTING DOCUMENTS – TABLE OF CONTENTS

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TAB 1
INTRODUCTION

1.0 INTRODUCTION

Yukon Energy Corporation's (YEC or Yukon Energy) 2023/24 General Rate Application (the GRA or Application) includes 10 tabs of supporting documents reviewing information related to Yukon Energy's operations, revenue requirements for the test years, and requested approvals.

Tab 1 provides an introduction to the remaining supporting documents, and reviews the following:

- Context and Approach for Current Rate Application
- Drivers of 2023 and 2024 Rate Increases
- Other Regulatory Issues
- Yukon Energy Rates and Bills

1.1 CONTEXT AND APPROACH FOR CURRENT RATE APPLICATION

1.1.1 Background on Yukon Energy Corporation (YEC)

YEC was established in 1987. It is a publicly owned electrical utility that operates as a business, at arm's length from the Yukon government. YEC is the main generator and transmitter of electrical energy in Yukon [provides over 98% of the total Yukon Integrated System firm load generation].

There are more than 23,000 electricity consumers in the territory. YEC directly serves over 2,300 of these customers, most of whom live in and around Dawson City, Mayo and Faro, and two industrial customers across the territory. Indirectly, YEC provides power to most other Yukon communities through ATCO Electric Yukon (AEY). AEY buys wholesale power from YEC and sells it to retail customers.

Most of the electricity YEC produces is renewable, coming primarily from hydro resources generated at its Whitehorse, Aishihik and Mayo hydroelectric facilities. A small amount of liquefied natural gas (LNG) and diesel is also generated to ensure electricity is available when it's needed at peak times, during emergencies and when renewable sources of electricity are not available.

1.1.2 Yukon Energy Challenges

The Yukon grid is not connected to any other province or territory. Yukon Energy therefore cannot import electricity when needed or export power to other jurisdictions when there is a surplus. For YEC and Yukoners, this means YEC only has itself to rely on to ensure it has enough capacity for cold winter days and to generate the electricity Yukoners need now and in the future.

Yukon Energy's isolated grid is currently challenged by multiple factors, including:

- High growth in non-industrial winter peak electricity demand, the related ongoing challenge of providing new dependable electricity winter capacity to supply homes and businesses, and the resulting impacts on needed investments, diesel rentals, staff resources, and overall YEC costs.
- Fluctuating industrial loads and related impacts on YEC revenue requirements to be recovered from residential and other commercial customers.
- Surplus of renewable summer energy that does not currently provide benefits to Yukon customers, and shortage of renewable winter resources to provide needed dependable winter electricity capacity.
- Electricity infrastructure that is aging or in need of being re-permitted, with major ongoing investment, staff, and other operating resource requirements for YEC.
- Small customer base without economies of scale for large investments.

1.1.3 Need for the Current Rate Application

All investments in Yukon's electricity system, unless offset by government funding, must be included in the Yukon's electricity rates. YEC's currently approved Return on Equity (ROE) is 8.65%. This level of ROE provides YEC with the equity capital needed to replace aging infrastructure and invest in renewable projects; however, when measured in terms of dollars, it provides only a modest amount of equity capital to be reinvested in operating the business in future years.

Without a rate increase, YEC forecasts:

- A revenue shortfall of approximately $6.7 million and ROE of 5.56% in 2023; and
- A revenue shortfall of approximately $15.3 million and ROE of 0.18% in 2024.

Such revenue deficiencies would not satisfy the requirements of *Rate Policy Directive (1995)*, OIC 1995/90 (as amended) as it is far below a fair return on equity. It would also make it a challenge to simply maintain what is in place now, with no resources to accommodate YEC's new and increasing demands.

1.1.4 Approach for the Current Rate Application

YEC is requesting incremental rate increases on October 1, 2023 and January 1, 2024 and in August 2024, to allow it to continue to provide Yukoners with an increasing supply of safe, reliable and sustainable electricity. As outlined in further detail below, these rate increases are required to recover the cost of significant and necessary investments in all aspects of Yukon's electricity system – including generation, transmission, distribution, storage and grid stability, and end-use.

As part of this Application -- and similar to the approach adopted in 2021 --YEC is seeking approval of YEC's interim rate increases and final rate adjustment to occur at times that other charges on electricity bills are expected to be reduced or removed from bills entirely. Through this method, the impact of YEC's 2023 and 2024 rate increases will be reduced, providing greater bill stability and predictability for Yukoners.

As summarized in Table 1-1 below, YEC's 2023 and 2024 proposed rate increase of 14.11% will equate to a 6.1% bill increase for residential customers using 1,000 kWh/month and 6.6% bill increase for commercial customers using 3,500 kWh/month. After the three YEC rate increases are applied, average monthly electricity bills when compared to bills in July 2023, are expected to be:

- $13 higher for typical residential customers using 1,000 kWh or $12 for typical residential customers using 850 kWh;
- $19 higher for typical commercial customers using 2,000 kWh or $52 for typical commercial customers using 3,500 kWh.

Table 1-1: GRA Rate Changes and Expected Bill Impacts [excl. AEY 2023/24 GRA impacts]

Date of Rate Adjustment	Rate increase	Avg. residential bill increase [1,000 kWh/month]	Avg. commercial bill increase [3,500 kWh/month]
October 1, 2023	3.34%	3.0%	3.0%
January 1, 2024	8.44%	0.0%	0.4%
August 1, 2024	2.33%	3.0%	3.0%
Total:	14.11%	6.1%	6.6%

1.2 DRIVERS OF 2023 AND 2024 RATE INCREASES

The 2024 test year forecast revenues at existing rates are $15.3 million short of the forecast revenue requirement, accounting for the 14.11% proposed increase in rates. Table 1-2 summarizes by cost components the 2024 and 2023 GRA revenue shortfalls and contributions to proposed rate increases. High level observations regarding cost component drivers for the 2024 GRA increase over 2021 approved include:

- Major rate increase drivers include capital cost increases ($6.0 million increase, 39% of total increase), non-fuel O&M increases ($5.6 million, 37% of total increase) and diesel rental cost increases ($3.3 million, 21% of total increase).

- Other notable rate increase drivers are fuel price increases ($1.3 million, 8% of total), IPP cost changes (net $1.3 million, 8% of total), and long-term debt rate increases ($1.1 million, 7% of total).

- The table also shows that energy revenue increases and long-term average (LTA) thermal cost reductions (at 2021 fuel prices) both acted to reduce the 2024 rate increase ($3.3 million or 22% offset to the total increase).

The Application describes four main factors driving the 2023-2024 revenue shortfall. Table 1-2 highlights the importance of each of these revenue shortfall drivers.

1. **Growth in winter peak electricity demand and the need for more dependable capacity:** Yukon's peak demand for electricity has increased by 23% in the last five years [from 2017 to 2022] and this trend is expected to continue with an additional 36% increase in non-industrial peak by 2030. In contrast, total YEC firm energy generation required for 2024 is lower than the 2021 approved forecast, reflecting the loss of the Minto mine industrial load and reducing the LTA

thermal generation forecast cost.[1] The following 2024 revenue requirement increase cost components reflect the winter peak demand growth cost driver:

- **Diesel Rental Cost -** $3.3 million of the 2024 shortfall (21% of total), with $1.2 million due to need for more rental units and $2.1 million due to higher rental prices.

- **Capital Costs rate base additions[2]** – $18.2 million for Thermal Replacement (Faro diesels), $4.3 million for Mayo-Faro Diesel Infrastructure, $11.2 million for Whitehorse Interconnection, $2.8 million (after contributions) for DSM deferred cost programs related to reducing dependable capacity requirements.

- **Non-fuel O&M Costs** – A portion of non-fuel O&M cost increases will be affected by this cost driver.

2. **Aging infrastructure:** Upgrading and replacing existing electricity assets, while at the same time renewing licences and permits for YEC's existing generation facilities, is critical to ensuring YEC's ability to continue to provide Yukoners with the electricity they need today while building and connecting the new sources of electricity needed in the future. The following cost increase components reflect this aging infrastructure cost driver:

- **Capital Costs rate base additions** - $30.3 million for multiple major capital projects addressing transmission, generation infrastructure and review (see Tab 5, section 5.2.1).

- **Overhauls Capital Costs -** $6.4 million from 2022 to 2024.

- **Deferred Cost rate base additions -** $4.5 million on Aishihik Relicensing (Five Year Licence Renewal).

- **Intangible Assets rate base additions** - $10.0 million for Asset Management projects (PAMMS Asset Management Framework, Enterprise Asset Management (EAM) System Purchase and Implementation).

- **Non-fuel O&M Costs** – A portion of non-fuel O&M cost increases will be affected.

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[1] The increased revenues for 2024 shown in Table 1-2 reflect offset impacts on revenues due mainly to higher YEC commercial retail sales forecast. See Tab 2, Table 2-1 for changes in sales by customer class, and Table 2-2 for YEC generation changes.

[2] Major capital cost projects with $1 million or more costs impacting 2024 test year rate base are identified without breaking out capital cost factors in Table 1-2, e.g., depreciation, amortization, return on rate base.

3. **Energy transition:** Yukon's electricity system is in a state of transformation with rapid changes to the way Yukoners both consume and produce electricity. As governments pursue targets to lower greenhouse gas emissions locally and nationally, they turn to electricity as a cleaner alternative to fossil fuels used in the heating and transportation sectors. Supporting these climate objectives requires significant investments in all aspects of Yukon's electricity system. The following cost components reflect this energy transition cost driver (some of these cost driver factors also impact the earlier factor "Growth in winter peak electricity demand"):

    - **Independent Power Production (IPP) Cost Changes** - $3.1 million added power purchase cost offset by $1.8 million reduction in LTA thermal costs (net impact of $1.3 million).

    - **Capital Cost rate base additions** - $7.9 million for WH 2 Uprate and WH4 Servomotor Replacement (the portion previously disallowed by the YUB).

    - **Non-fuel O&M Costs** – A portion of non-fuel O&M cost increases will be affected.

4. **Rising costs and project complexity:** Like other businesses in Yukon, YEC is not immune to external pressures such as inflation, increased labour costs, and supply chain delays and constraints experienced in recent years. More resources are required to direct, plan, execute and oversee the way Yukon Energy responds to today's challenges - the needs of larger projects both in terms of project scope and expenditure, the requirements for more projects to connect new customer extensions and distributed energy sources to the grid, and the greater stakeholder expectations and involvement in the way YEC's work is done. The following cost components reflect the rising costs and project complexity cost driver:

    - **General Inflation** – YEC and Yukon have experienced the recent higher inflation impacts that have affected all other markets.

    - **Rate changes for fuel prices, long-term debt costs, diesel rentals** - $4.5 million added 2024 costs due to rate / price increases for fuel, long-term debt and diesel rentals (see Table 1-2). Fuel price changes would be addressed by Rider F if there was no GRA.

    - **Non-fuel O&M Costs** – A portion of non-fuel O&M cost increases will be affected by this cost driver, especially for YEC added labour costs (both the increase in salaries and staffing requirements – see Tab 3 for details).

Table 1-2:
Summary of Revenue and Cost Changes – 2021 Approved vs 2023/ 2024 GRA

Summary of impacts, $000

2023/24 Revenue Shortfall Drivers	2023 GRA over 2021 Approved ($000)	% share of 2023 Rate Increase	2024 GRA over 2021 Approved ($000)	% share of 2024 Rate Increase
Capital Costs	**563**	**0.53%**	**6,004**	**5.53%**
Depreciation (fixed asset increases)	*1,060*	*0.99%*	*2,465*	*2.27%*
Deferred costs amortization	*-1,951*	*-1.83%*	*-14*	*-0.01%*
Amortization of Customer Contributions	*257*	*0.24%*	*78*	*0.07%*
Long-term debt cost - rate base change	*404*	*0.38%*	*1,172*	*1.08%*
ROE increase - rate base change	*793*	*0.74%*	*2,302*	*2.12%*
Long-term debt cost - rate change	*748*	***0.70%***	*1,104*	***1.02%***
ROE - rate change	*67*	***0.06%***	*75*	***0.07%***
Energy Load (GWh) Changes	**-2,966**	**-2.78%**	**-3,311**	**-3.05%**
Added revenue impact at existing rates	*-1,524*	*-1.43%*	*-1,856*	*-1.71%*
Long Term Average (LTA) thermal cost [1]	*-1,442*	*-1.35%*	*-1,455*	*-1.34%*
Diesel Rental Cost[5]	**1,512**	**1.42%**	**3,269**	**3.01%**
Fuel Price Changes[2]	**1,397**	**1.31%**	**1,279**	**1.18%**
Non-Fuel O&M Costs	**4,912**	**4.61%**	**5,640**	**5.20%**
Labour cost increase	*2,167*	*2.03%*	*3,063*	*2.82%*
Non-labour O&M [3]	*2,745*	*2.57%*	*2,577*	*2.37%*
Independent Power Production (IPP) Cost Changes	**437**	**0.41%**	**1,262**	**1.16%**
Added Power Purchase Cost	*1,099*	*1.03%*	*3,085*	*2.84%*
Impact to Long Term Average (LTA) thermal [4]	*-662*	*-0.62%*	*-1,822*	*-1.68%*
Other Cost Changes	**-2**	**0.00%**	**-2**	**0.00%**
Total Revenue Shortfall	**6,667**	**6.25%**	**15,320**	**14.11%**
Required Rate Increase	6.25%		14.11%	

Notes:
1. Excludes LTA fuel price impact and LTA impacts from IPPs [shown separately].
2. Fuel price impact compared to the 2021 GRA for total LTA thermal change.
3. Excludes Diesel Rental cost.
4. LTA thermal volume impact [excludes fuel price change impact].
5. $2.2 million of $3.3 million 2024 diesel rental increase is due to price increase, $1.2 million due to more units.

In summary, the two major rate driver cost components (capital costs and non-fuel O&M costs) are each affected by all of the four major rate drivers reviewed above.

Capital cost increases reflect mid-year net rate base increases of $66.5 million (21.5%) from 2021 approved to the 2024 test year. Tab 5 provides detailed review of each capital cost project having material impacts on test year rate base.

Non-fuel O&M cost increases are reviewed in detail in Tab 3. Key elements of these cost changes are summarized below:

Rising labour costs

For 2023, labour rates have been escalated by 4 percent, which is consistent with approved increases for Yukon government employees. For 2024, labour rates have been escalated by 3 percent also consistent with approved increases for Yukon government employees.

A vacancy factor of 9 FTEs has been applied to labour expenses for the 2023-2024 test years. This is based on a 5-year historical average. The vacancy factor for the 2021 GRA was 5 FTEs excluding 3 new FTEs the YUB directed to remove from the revenue requirements in its Order 2022-03, Appendix A.

Staff positions

YEC is forecasting an increase of approximately 19 FTEs in 2024 over the approved 2021 FTEs. However, YEC also increased the vacancy factor which reduces the impact on the net labour cost. The details of the FTE additions are provided in Tab 3.

The additional positions, as outlined in Tab 3, are required to plan, permit, execute and deliver YEC's $85 million/year capital budget forecasted in the 2023 and 2024 test years and anticipated future capital requirements as the energy transition continues to unfold. YEC's forecast 2023 and 2024 annual capital programs are nearly double the size they were prior to 2021. Additional staff positions are needed who possess the training and knowledge to build and connect new projects to meet growing demands for electricity; to replace and upgrade assets that are nearing or at end-of-life; and to plan, deliver and oversee more complex projects with multiple groups of rightsholders and stakeholders, both in terms of scope and expenditures.

In addition, maintenance for plant operations, and environmental monitoring and compliance requirements for YEC's entire electricity system has increased. This is due to the growing number of generation assets that are now connected to the Yukon grid, the additional maintenance needed to continue to operate them safely and reliably, and the monitoring programs required to monitor and adapt to changing climate conditions.

The remaining added FTEs address the needs of a growing number of customers and stakeholders, managing demand-side management programs, higher vendor and employee expense payment volumes, additional reporting needs, including KPI and ESG reporting, etc., and a need to strengthen strategic planning and communications with all levels of government through the energy transition. Please see full details in Tab 3.

Non-Labour O&M excluding Diesel Rentals

Non-labour O&M (excluding diesel rentals) 2024 cost increase of $2.577 million over 2021 approved relates to a range of elements affected by YEC's cost drivers, with Insurance accounting for about 38% of this increase, Administration for about 40% of this increase, and Production (ex. diesel rentals) for about 22% of this increase.

1.3 OTHER REGULATORY ISSUES

Aside from the need to address revenue requirement shortfalls at existing rates, the current Application identifies two other regulatory issues that need to be addressed concurrently with the Application:

- YEC is requesting approval of an IPP Purchase Cost Deferral Account that captures variances in IPP purchase costs included in the test year revenue requirements and actual purchase costs offset by IPP LTA thermal displacement benefits calculated using 59% LTA thermal displacement benefits (see Tab 3, Section 3.6.4).

- Pursuant to Rate Schedule 39, a Fixed Charge is assigned to industrial customers that use the Mayo-Keno transmission facilities. The basis and premise for the Fixed Charge was initially reviewed as part of the Alexco Resource Corp Power Purchase Agreement (PPA) approved in 2011 by Order 2011-01, and confirmed in the VGC Group PPA approved in 2018 by Board Order 2018-04. This application is seeking approval to implement an interim refundable Fixed Charge for VGC Group of $46,554.84/month and for Hecla Yukon (previously Alexco) of $21,295.74/month effective January 1, 2024 (see Appendix 4.3).

1.4 YUKON ENERGY RATES AND BILLS

Since Yukon Energy was established in 1987, rate matters related to Yukon Energy and AEY typically have been 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 Orders in Council establishing equalized rates in Yukon, the most recent being the *Rate Policy Directive (1995)*, OIC 1995/90 with various subsequent amendments.

Tab 10 provides copies of the current OIC's directing the Board on rate determinations. The current OIC 1995/90 is provided, integrating the impact of OIC directives amending it since 1995.

The Board directly determines rates (other than Rider F for diesel or natural gas 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 2021 GRA:

1. **Rider F (Diesel or Natural Gas Fuel Price Changes and Rate Schedule 32 Changes)** – Per direction provided in Order 2010-13 quarterly updates are filed with the Board. Rider F adjusts all firm retail and industrial bills for changes in diesel or natural gas fuel prices and Rate Schedule 32 rates since the last YEC or AEY GRA. The current Rider F is 1.635 cents per kW.h and was last changed as at January 1, 2023.

2. **Interim Electrical Rebate (IER)** – The Government of Yukon provides for a 2.262 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 with adjustments since that time.

TAB 2
SALES AND GENERATION

2.0 SALES AND GENERATION

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 for the Yukon Integrated System.

Yukon Energy directly serves about 2,400 customers at the distribution (retail) level, most of whom live in and around Dawson City, Mayo and Faro. Indirectly, Yukon Energy also provides power to Yukon retail customers served on the Integrated System (including those located in Whitehorse, Carcross, Carmacks, Haines Junction, Ross River and Teslin, Pelly Crossing, Keno and Stewart Crossing) through its wholesale sales to ATCO Electric Yukon (AEY).

Actual firm sales to **non-industrial customers** (excluding secondary or interruptible customer load) supplied by Yukon Energy on the Integrated System in 2021 was 396.2 GWh, which was 3.9 GWh higher compared to the approved forecast load of 392.2 GWh primarily due to an increase in firm wholesales to AEY. The actual firm sales to non-industrial customers in 2022 was 394.5 GWh, a reduction of 1.6 GWh over 2021 actual primarily due to lower wholesales. The forecast non-industrial firm sales in 2023 is 407.7 GWh [reflecting January-May preliminary actuals and forecasts for June-December], which is an increase of 13.2 GWh over 2022 actuals primarily due to higher general service (reflecting Minto mine care and maintenance) and wholesale sales. The forecast non-industrial firm sales for the 2024 test year is 418.8 GWh, an increase of 11.1 GWh over 2023 forecast, again primarily due to higher general service and wholesale sales.

Industrial sales under Primary Industrial Rate Schedule 39 includes sales to Victoria Gold Corporation Group's[1] Eagle Gold (Victoria Gold or "VG"), Hecla Yukon (previously Alexco Resources), and Minto Metals

[1] The Victoria Gold Corporation Group is the amalgamation of Victoria Gold Corporation and Stratagold Corporation as described in the Power Purchase Agreement for the Eagle Gold mine.

Corporation (Minto Mine).[2] The actual industrial sales for 2021 were 91.1 GWh compared to forecast sales of 102.9 GWh [primarily due to lower VG and Hecla Yukon sales offset partially by higher Minto sales]. The actual industrial sales in 2022 were 95.2 GWh, 4.0 GWh higher than 2021 actuals. The forecast sales for the 2023 test year at 75.0 GWh reflects a decrease of 20.1 GWh from 2022 actuals due to closure of Minto industrial operations after May 2023, and the forecast sales for the 2024 test year is 69.4 GWh, reflecting a decrease of 5.7 GWh from 2023 forecast (reflects impacts of the Minto mine closure in May 2023 – VG and Hecla Yukon sales are forecast to increase in both 2023 and 2024).

Overall, the **total firm generation load** to be supplied by Yukon Energy on the Yukon Integrated System was forecast at 538.7 GWh in the 2021 GRA Compliance Filing. The actual total firm generation load was 528.3 GWh in 2021 reflecting lower sales and losses compared to the forecast. The actual total firm generation load in 2022 was 533.7 GWh, about a 1% increase over 2021 actuals. The forecast total firm generation load for the 2023 test year is 525.5 GWh, about a 1.6% decrease from 2022 actuals, and for the 2024 test year is 531.2 GWh, about a 1.1% increase over 2023 forecast.

Non-firm secondary sales ceased in the fall of 2018 due to load growth and a lack of water resources for hydro generation.[3] Therefore, no secondary sales were included in the 2021 GRA based on information that was available when the 2021 GRA load forecast was prepared. Due to high water conditions, the secondary sales resumed in June 2021 with actual secondary sales of 4.7 GWh in 2021 and 3.4 GWh in 2022. For the 2023/24 GRA, the secondary sales forecast is 2.9 GWh for each test year.

Section 3 of OIC 2021/16 directs that forecast fuel costs to be included in rates for thermal generation to meet forecast customer requirements are to be based on long-term average (LTA) annual renewable resource availability (rather than forecasts of actual hydro generation resulting from actual water conditions). Accordingly, for the purpose of the 2023/24 GRA test years, hydro and thermal generation forecasts are based on LTA water supply for hydro generation as updated with the latest information.

- The approved 2021 GRA Compliance Filing, based on annual LTA hydro generation capability, forecast that about 84% of grid generation requirements in 2021 would be met with hydro generation and about 16% with thermal generation. Based on the actual load in 2021, hydro generation at LTA supply was calculated at 85% of 2021 grid generation and LTA supply thermal

[2] Yukon government's May 13, 2023 new release, https://yukon.ca/en/news/yukon-government-hires-contractor-ensure-environmental-protection-minto-mine, noted that Minto Metals Corporation has indicated that it is not able to continue operations at the site and has hired a contractor, JDS, to ensure environmental protection is maintained at the Minto Mine. Minto Mine is included as an industrial customer for January-May 2023. For June-December 2023 and 2024 the load for Minto care and maintenance is included under the general service class.

[3] Temporary secondary sales occurred during September 2020 due to high water conditions.

generation accounted for about 15% of 2021 grid generation. Actual hydro generation in 2021 was 92.5% of grid generation, reflecting higher than LTA water availability.

- In 2022, hydro generation at LTA was calculated at 84.9% of grid generation, Independent Power Production (IPP) at 0.4% and related thermal generation accounted for about 14.7% of 2022 grid generation. Actual hydro generation in 2022 was 91.6% of grid generation, reflecting higher than LTA water availability.

- The 2023 and 2024 forecast firm generation, 525.5 GWh and 531.2 GWh respectively, result in forecast hydro generation at LTA supply accounting for 84.7% of grid generation in 2023 and 84.0% in 2024 and related forecast thermal generation accounting for 14.2% of grid generation in 2023 and 12.8% in 2024.

- IPP renewable generation is forecast at 1.2% of forecast grid generation in 2023 and 3.2% in 2024.

Over the last decade the forecast LTA thermal generation on the YIS increased as the total generation requirement increased – however, the 2023/24 GRA shows some reductions in total generation requirement and LTA thermal generation:

- The 2012/13 GRA Compliance Filing approved a forecast of 11.0 GWh for LTA thermal generation requirements to supply the 2013 forecast grid load of 416.4 GWh (2.6% LTA thermal).

- The 2017/18 GRA Compliance Filings approved a forecast of 16.4 GWh LTA thermal generation requirements to supply the 2018 forecast grid load of 420 GWh (3.9% LTA thermal).

- The 2021 GRA Compliance Filing approved a forecast of 84.3 GWh LTA thermal generation requirements to supply the 2021 forecast grid load of 538.7 GWh (15.6% LTA thermal).

- For the 2023 test year the LTA thermal generation requirements at 74.5 GWh to supply the 2023 forecast firm grid load of 525.5 GWh (14.2% LTA thermal) and for the 2024 test year the LTA thermal generation requirements at 68.1 GWh to supply the 2024 forecast firm grid load of 531.2 GWh (12.8% LTA thermal). Reduced LTA thermal compared to the 2021 GRA reflects lower forecast grid generation and (for 2024 in particular) the growth of IPP renewable generation.

Winter peak generation on the Yukon Integrated System (including industrial load) has continued to increase in recent years, with the 2021 actual peak at 104.4 MW and the 2022 actual peak reaching 114.2 MW. Forecast YIS peak load for the test years is 119.5 MW for 2023 and 123.2 MW for 2024.

Excluding industrial load, the forecast peak load in this Application is 110.9 MW in 2023 (based on winter 2023/24) and 114.6 MW in 2024 (based on winter 2024/25). 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 without rented diesel units is forecast at 35.3 MW for 2023 and 35.99 MW for 2024 based on the non-industrial peak loads forecast in this Application. With rented diesel units as planned, there is no shortfall in dependable capacity under the N-1 criterion. Please see section 2.4 for details.

2.2 SALES FORECAST

Yukon Energy's actual energy sales for 2021 and 2022, and forecast sales for 2023 and 2024 are summarized in Table 2.1 at the end of this tab.

Total forecast firm sales are 482.8 GWh for the 2023 test year and 488.2 GWh for the 2024 test year. Total forecast firm sales include 351.3 GWh (2023) and 355.9 GWh (2024) of primary firm wholesale sales, 75.0 GWh (2023) and 69.4 GWh (2024) of primary major industrial sales, and 56.4 GWh (2023) and 62.9 GWh (2024) 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 (72.8% in 2023 and 72.9% in 2024).

Actual firm wholesales in 2021 were 349.0 GWh compared to the forecast of 343.5 GWh in the 2021 GRA. Higher actual wholesales in 2021 were primarily due to colder-than-normal weather. The 2022 actual wholesales of 346.3 GWh were 2.6 GWh lower than 2021 actual due to warmer weather [2022 was warmer compared to 2021] and the impact of incremental micro-generation.

The forecasts for 2023 and 2024 are prepared based on multi-variate regression assessments of monthly wholesales changes, the same approach used in the 2021 GRA, at normal weather conditions using the 20-year historical averages. It also reflects forecast micro-generation which reduces forecast wholesales.[4]

Firm wholesales for 2023 are forecast in Table 2.1 at 351.3 GWh [reflecting January-May actuals and June-December forecasts], which is 4.9 GWh or 1.4% higher than 2022 actual; firm wholesales for 2024

[4] Micro-generation forecast is 8.2 GWh in 2023 and 9.7 GWh in 2024 as per information available from Energy Mines & Resources of the Yukon government.

are forecast at 355.9 GWh which is 4.6 GWh or 1.3% higher than the 2023 forecast. The forecasts assume AEY Fish Lake generation at 8.7 GWh, the long-term average approved by the YUB.

The YUB in Board Order 2022-03 directed that YEC in future GRA submissions provide details on discussions with AEY to align their wholesale sales forecasts. In preparation of the 2023/24 GRA, YEC reached out to the AEY Regulatory team and provided updates regarding YEC's GRA wholesale forecast.[5] YEC and AEY staff worked to understand forecasting methodology and inputs into their respective forecasts. As reviewed below, each company decided to proceed with its respective forecasts for 2023 and 2024 in the GRAs that have been filed.

AEY filed its 2023/24 GRA with forecast firm power purchase forecast at 349.5 GWh for 2023 and 362.4 GWh for 2024 or an increase of 3.7% in 2024 over 2023. The AEY forecast for 2023 is 1.8 GWh or 0.5% lower than YEC's forecast, while AEY forecast for 2024 is 6.5 GWh or 1.8% higher than YEC's forecast. Given YEC's forecast growth rates of 1.4% in 2023 and 1.3% in 2024 are within the historical growth range [the average annual increase for the last five years at 1%], and 2023 year-to-date actuals were at the forecast level, YEC is using YEC's forecasts of 351.3 GWh for the 2023 test year and 355.9 GWh for the 2024 test year.

2.2.2 Major Industrial

Victoria Gold and Hecla Yukon (previously Alexco) continue to be forecast as Major Industrial Customers[6] during the test years. Minto Mine is included as an industrial customer for January-May 2023; for June-December 2023 and 2024 the load for Minto care and maintenance is included under the general service class.[7]

The 2021 actual sales were at 91.1 GWh and the 2022 actual sales were at 95.2 GWh. The forecast sales for the 2023 test year at 75.0 GWh reflects a decrease of 20.1 GWh from 2022 actuals and the forecast sales for the 2024 test year is 69.4 GWh, reflecting a decrease of 5.7 GWh from 2023 forecast.

- The Minto Mine actual load in 2021 of 44.1 GWh was 8.4 GWh higher compared to the approved forecast load of 35.7 GWh. Higher overall actual results for 2021 were due to increased mine

[5] YEC exchanged load forecasts with AEY when there was an update to YEC's forecast. AEY agreed to review YEC forecasts but did not recommend any changes.
[6] 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."
[7] Yukon government's May 13, 2023 new release, https://yukon.ca/en/news/yukon-government-hires-contractor-ensure-environmental-protection-minto-mine, noted that Minto Metals Corporation has indicated that it is not able to continue operations at the site and has hired a contractor, JDS, to ensure environmental protection is maintained at the Minto Mine. Minto Mine is included as an industrial customer for January-May 2023. For June-December 2023 and 2024 the load for Minto care and maintenance is included under the general service class.

activities which resulted in higher consumption by mine compared to the estimate provided by the customer. In 2022 the actual load was 47.9 GWh which is a 3.8 GWh further increase over 2021 actuals. As indicated above, Minto Mine is included as an industrial customer for January-May 2023 based on actual sales of 16.3 GWh; for June-December 2023 and 2024 the load for Minto care and maintenance is included under the general service class.

- Victoria Gold actual load in 2021 of 36.9 GWh was 6.2 GWh lower compared to the approved forecast load of 43.1 GWh. The actual load for 2022 was 37.5 GWh. Based on the information provided by Victoria Gold, the load forecast for 2023 is 43.6 GWh [including January-May actuals] and 47.6 GWh for 2024. Victoria Gold has significantly reduced its forecast load from what it forecast in its 2017 Power Purchase Agreement.[8] The reductions in forecast loads reflect experience to date after the start of production; current forecasts from the customer indicate a gradual increase in loads over the next two years.

- Hecla Yukon (previously Alexco) resumed industrial operations in late 2020 in the Keno region north of Mayo and east of the Eagle Gold mine. The actual load for 2021 was 10 GWh which is 14 GWh lower compared to the approved forecast of 24.1 GWh. The actual load for 2022 was 9.8 GWh. Based on the information provided by Hecla Yukon, the load forecast for 2023 is 15.1 GWh [including January-May actuals] and 21.8 GWh for 2024 reflecting an increase in mine activities starting from mid-2023.

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 is not aware of any other potential near-term mine loads that could be connected to the grid during the GRA test years.

[8] Section 5.1 of the Power Purchase Agreement forecast 51.8 GWh for year 1 of operation (12 months) of operation (assumed connection March 2019, approximately four months before forecast first gold production), 63.6 GWh for year 2 of operation, 67.4 GWh for year 3, 70.2 GWh for year 4, 72.6 GWh for year 5, and 74.1 GWh for year 6.

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 [Dawson City, Mayo, North Klondike Highway, Faro, Champagne, Braeburn, Johnson Crossing]. Retail sales are forecast at 56.4 GWh for the 2023 test year and 62.9 GWh for the 2024 test year compared to actual sales of 47.2 GWh in 2021 and 48.2 GWh in 2022. The increase mostly reflects the Minto Mine closure after May 2023 and its related care and maintenance load as discussed below.

2.2.3.1 Residential Sales

Actual firm residential retail sales were 17.4 GWh in 2021 and 17.3 GWh in 2022; the forecast for 2023 is 17.7 GWh or a 2.1% increase from 2022 actuals and for 2024 is 18.1 GWh or a 2.2% increase from 2023 forecast. Residential sales forecasts are based on historical trends and input from YEC staff that is obtained through their work in the communities. The forecast growth in 2023 and 2024 is also consistent with the population growth projections by the Yukon Government and the City of Whitehorse projections.[9]

2.2.3.2 General Service Sales

Actual firm general service retail sales were 29.6 GWh in 2021 and 30.7 GWh in 2022; the forecast for 2023 is 38.6 GWh and the forecast for 2024 is 44.7 GWh. General Service sales forecasts are based on historical trends and input from YEC staff that is obtained through their work in the communities.

Two large General Service customers account for 51% of 2024 firm general service forecast retail sales:

- Actual sales to the Faro Mine remediation project were 9.4 GWh in 2021 and 9.7 GWh in 2022, accounting for 32% of all general service sales. The forecasts for 2023 [including January – May actuals] and 2024 is 9.8 GWh are based on actual sales for 2022.

- Minto Mine care and maintenance load is included under the general service class after May 2023 with a forecast at 8.0 GWh for 2023 and 13.1 GWh for 2024.

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[9] City of Whitehorse January 2023 Official Community Plan uses 1.60% annual growth under preferred growth rate and 2.04% under high growth rate; Yukon Bureau of Statistic population growth projection for 2023 and 2024 at 2-2.1%.

2.2.3.3 Lighting (Street Lights and Space Lights)

Actual firm retail sales for lighting were 177 MW.h in 2021 and 2022, and forecast to be at 177 MW.h for the 2023 and 2024 test years.

2.2.4 Secondary Sales

Secondary sales ceased in the fall of 2018 due to load growth and a lack of water resources for hydro generation.[10] Therefore, no secondary sales were included in the 2021 GRA based on information that was available when the 2021 GRA load forecast was prepared. Due to high water conditions, the secondary sales were resumed in June of 2021 with actual secondary sales of 4.7 GWh in 2021 and 3.4 GWh in 2022. For the 2023/24 GRA, the secondary sales forecast is at 2.9 GWh for each test year [no secondary sales for January-May 2023].

2.3 POWER GENERATION

Hydro generation remains the predominant source of generation forecast for the test years, and is expected to be supplemented by natural gas (liquefied natural gas (LNG)) and diesel thermal generation as required. Table 2.2 provides a summary of forecast power generation by source, including forecast power generation required to be purchased by YEC from Independent Power Production (IPP) projects through the Standing Offer Program (SOP) under the Independent Power Production policy.

Total generation is based on the sum of total sales plus losses. The line losses are calculated at the YEC grid load level as the variance between metered generation and sales. The 2021 GRA approved forecast losses were 8.8%. Actual losses were 8.4% in 2021 and 9.0% in 2022. The losses are forecast at 8.8% for the 2023 and 2024 test years which is the same as the 2021 GRA approved level and also within the range of historical losses for the last three years [2020 at 9.1%, 2021 at 8.4% and 2022 at 9.0%].

2.3.1 Integrated Grid Hydro Generation

The Yukon Integrated System (YIS) has 92.1 MW of installed YEC hydro generation, of which approximately 71.1 MW can be relied upon for the winter peak.

Section 3 of OIC 2021/16 directs that forecast fuel costs to be included in rates for thermal generation to meet forecast customer requirements are to be based on long-term average (LTA) annual renewable resource availability (rather than forecasts of actual hydro generation resulting from actual water

[10] Temporary secondary sales occurred during September 2020 due to high water conditions.

conditions). Accordingly, for the purpose of the 2023/24 GRA test years, hydro and thermal generation forecasts are based on LTA water supply for hydro generation as updated with the latest information as well as available information for IPPs.

As reviewed in Table 2.2, LTA YEC hydro generation for 2021 at 449.9 GWh for the actual firm generation load 528.3 GWh compared to the 2021 GRA forecast LTA hydro at 452.8 GWh for the forecast generation load of 538.7 GWh. LTA YEC hydro generation for 2022 was 453.2 GWh. The proposed forecast LTA YEC hydro generation for 2023 is 444.9 GWh and for 2024 is 446.2 GWh, utilizing updates to the LTA forecast (see Section 2.3.2). In addition, Table 2.2 shows the forecast LTA IPP generation of 6.1 GWh for 2023 and 16.8 GWh for 2024.[11]

Table 2.2 also shows actual (as opposed to LTA) hydro generation for 2021 and 2022, and forecast hydro generation for 2023 and 2024 based on available information. Actual hydro generation for 2021 and 2022 indicates the extent to which favourable water conditions in each of these years resulted in forecast actual hydro generation higher than LTA. The forecast hydro generation for 2023 and 2024 also reflects favourable water conditions with actual hydro generation currently expected to be higher than the LTA for both 2023 and 2024.

In years with normal water conditions, the integrated system typically operates with Whitehorse Hydro as first-on generation (outside of 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 the 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, thermal generation sources are required to supplement available hydro to meet the system's winter/spring seasonal generation requirements, to provide reliable energy generation in drought years and to otherwise provide backup generation on the YIS when hydro is otherwise unavailable (e.g., breakdown/maintenance requirements). Conversely, on the isolated grid there is no opportunity to export surplus hydro (or other renewable generation such as IPPs) 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:

[11] These IPP generation forecasts assume the currently connected three IPPs, two solar IPPs connecting in July and August of 2023, two wind IPPs connecting in October 2023, one solar IPP connecting in September 2024 and three solar IPPs connecting in December 2024. See Appendix 5.1B, Distribution projects "IPP Connections" for more information on specific IPP projects.

- **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. IPP resources can reduce thermal energy generation requirements – but the wind and solar IPPs included in the GRA test years provide intermittent energy supplies and do not contribute to YIS dependable capacity requirements.

- **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

Yukon Energy's annual thermal generation costs for the 2023 and 2024 test years are based on the forecast total firm generation requirement less LTA hydro and IPP generation forecasts (as updated with the latest information) for the forecast firm generation load.

Table 2.2 shows LTA thermal generation for 2021 as approved at 85.9 GWh based on the forecast load of 538.7 GWh, versus LTA thermal generation of 78.3 GWh based on actual 2021 firm load of 528.3 GWh. Table 2.2 also shows actual (as opposed to LTA) diesel and natural gas thermal generation for 2021, highlighting the extent to which favourable water conditions (and the related higher than LTA hydro generation) resulted in actual thermal generation at 40.1 GWh being well below LTA thermal.

Table 2.2 shows 2022 LTA thermal generation of 78.6 GWh based on the actual firm load compared to actual thermal generation at 43.4 GWh, also due to favourable water conditions.

The forecast 2023 LTA thermal generation is 74.5 GWh and for 2024 is 68.1 GWh. The forecasts for the test years are based on proposed updates to the determination of LTA annual hydro availability for the current GRA as outlined in Appendix 2.1, including the following:[12]

[12] See Appendix 2.1 for more detailed review of the updated LTA hydro determinations and related expected LTA thermal generation requirements at various grid loads with updates in Table 2.1-1 to reflect changes in industrial load shape/ volume as well as grid generation capabilities; information on additional water years was also included given the other updates required.

- Yukon Energy now has more water year records compared to 2021 GRA [41 water years, from 1981 to 2021, compared to 38 water years, 1981 to 2018, used in 2021 GRA]. This added information has tended to increase LTA hydro estimates.
- Updated reservoir and generation station water flow requirements changes, including 10-year average for Aishihik Lake spring water levels to reflect water years as noted above.
- Updated load curves reflecting changes to monthly sales related to non-industrial and industrial load shape, including impact of Minto load and/or volumes.
- Loads to reflect expected IPPs for 2023 and 2024.
- Incorporated benefits of Whitehorse Rapids Generating Station Unit #2 Uprate and Unit #4 Servomotor.[13]

It is assumed in the Application that 90% of LTA thermal generation requirements as forecast for the test years will be met by liquified natural gas (LNG), with the balance (10%) supplied by diesel generation. This ratio was used both in the 2017/18 GRA and 2021 GRA, and is considered a reasonable ratio for the 2023 and 2024 test years on an LTA basis.[14] YEC has no reason to believe there should be a change at this time to the 90% LNG/10% diesel for thermal split purposes under LTA water conditions.

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 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. To ensure proper maintenance and reliability, the diesel and LNG units need to be run at certain times solely for maintenance purposes, especially during the summer months. See Section 3.2 for further details and forecasts of thermal fuel consumption for maintenance activities.

[13] In the 2021 GRA, the expected incremental hydraulic generation from WH2 uprate and WH4 servomotor/uprate projects was 4.2 GW.h based on a half-year impact for 2021 [7.1 GWh/year] and was manually adjusted after the model runs [please see 2021 GRA, Appendix 2.1, Table 2.1-1 note #7]. For 2023/24 GRA, YECSIM model inputs are adjusted to reflect the uprate projects and Tables 2.1-1 and 2.1-2 already reflect the incremental hydro generation. The annual expected incremental hydraulic generation is about 6.3 GW.h at 2024 load levels [overall firm generation load in 2024 is lower compared to the 2021 GRA firm load].

[14] Lower actual LNG generation numbers reflect water conditions above LTA (with lower thermal requirements it is more efficient running diesel units) and impacted by colder-than-normal weather that resulted in high loads with diesel generation being required to supply baseload energy as available LNG units were running at max output.

2.4 PEAK DEMAND FORECAST AND DEPENDABLE CAPACITY REQUIREMENT

Peak Demand Forecast

As indicated in Table 2.2, the peak demand for the integrated system is forecast to be 119.5 MW in 2023 and 123.2 MW in 2024.[15] The actual peak demand was 104.4 MW in 2021 and 114.2 MW in 2022.

Yukon Energy's 10-Year Renewable Electricity Plan developed a long-term energy and peak forecast which were updated from the 2016 Resource Plan by Itron using an econometric model. The Itron model uses a range of input data, including historical sales and energy data by customer class, economic activity, population projections, electricity prices, and improvements in end-use efficiency and standards, and system design temperature to produce a long-term peak forecast. The model also takes into account the impact of Yukon's strategy for climate change, energy and a green economy, particularly as regards future peak loads related to ongoing initiatives for electrification, electric vehicles, and heat pumps.

The initial forecast was prepared by Itron in 2018 based on a -35 deg C design temperature (the coldest average temperature in Whitehorse in the last 10 years). In 2019, the long-term peak forecast design temperature was updated to -37 deg C based on the new record coldest day from January 2019. The current updated peak forecasts use -39 deg C based on the new coldest day record from January 2022.

YEC continues to communicate with relevant stakeholders in order to ensure the load forecasts are as accurate as possible. As noted in sections 2.2.1 and 2.2.2, YEC worked closely with AEY as well as with major industrial customers during the preparation of the load forecasts in the current application. The peak forecasts were developed using an econometric model that takes into account wide-range projections [i.e., other stakeholders inputs].

Dependable Capacity to meet Peak Demand

At these forecast peak levels for the test year (which exceed reliable winter hydro dependable generating capacity of approximately 71.1 MW),[16] 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

[15] 110.9 MW non-industrial and industrial peak at 8.5 MW forecast to occur in December 2023, 114.6 MW non-industrial and 8.6 MW industrial peak forecast to occur in December 2024. Non-industrial peak is forecast at -39 deg. C.
[16] This reflects 37 MW at Aishihik, 6.5 MW at Mayo and 27.6 MW at Whitehorse [an increase from 27 MW in the 2021 GRA].

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.[17] 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 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.[18]

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

[17] The WAF system had substantial hydro generation availability that is 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.

[18] 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.

using the existing software and modeling approach,[19] 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.[20]

The 2016 Resource Plan and the subsequent GRAs, 2017-18 GRA and 2021 GRA, indicated that the existing hydro and diesel infrastructure did not meet the single contingency (N-1) capacity planning criterion at the forecast grid loads (at the forecast industrial load, the LOLE criterion was satisfied in each test year so long as the single contingency [N-1] criterion was met).[21]

The dependable capacity based on the single contingency (N-1) criterion is forecast to be about 0.7 MW and 0 MW in excess of the forecast non-industrial winter peak for 2023 and 2024 respectively, as outlined below:

- Installed YEC and AEY dependable grid capacity for the 2023/24 winter based on existing capacity today and any planned additions/retirements and excluding Fish Lake hydro, is 148.9 MW (71.1 MW of YEC hydro, 12.6 MW YEC LNG, 23.5 MW of YEC diesel (reflects retirement of 2.5 MW FD1 at Faro), 5.6 MW of AEY diesel, 0.1 MW DSM and plus 36 MW[22] diesel from rented diesel units in order to meet the N-1 criterion assessment).[23]

- Installed YEC and AEY dependable grid capacity for the 2024/25 winter based on existing capacity today and any planned additions/retirements and excluding Fish Lake hydro, is 151.8 MW (71.1 MW of YEC hydro, 12.6 MW YEC LNG, 26.0 MW of YEC diesel [reflects retirement of 2.5 MW diesel at Dawson in 2024 and 5 MW added diesel replacements in Faro], 5.6 MW of AEY

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

[20] 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.

[21] 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.

[22] 20 units at 1.8 MW for each unit to total 36 MW for 2023 for N-1 dependable capacity purposes [excluding two spare units].

[23] Yukon Energy dependable winter capacity of 107.3 MW for 2023/24 winter includes 71.1 MW hydro including 37 MW at Aishihik, 6.5 MW at Mayo and 27.6 MW at Whitehorse [an increase of 0.6 MW for WH2 uprate]; 12.6 MW LNG and 23.5 MW diesel, including 3 MW in Faro [after FD1 retirement], 7.0 MW in Dawson, 2.95 MW in Mayo and 10.5 MW in Whitehorse]. The change from 2023/24 winter to 2024/25 winter [diesel change 23.5 MW to 26 MW or a net increase of 2.5 MW] reflects 2.5 MW reduction due to the retirement of two Dawson diesel units [DD2 at 1 MW and DD5 at 1.5 MW] and 5 MW increase for added Faro diesel replacement.

diesel, 0.6 MW DSM and plus 36 MW[24] diesel from rented diesel units in order to meet the N-1 criterion assessment).

- 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 110.4 MW for the N-1 event for 2023 and 113.3 MW for 2024 (assumes 37.0 MW at Aishihik and 1.5 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 dependable capacity is available to meet the projected non-industrial grid winter peak load (excluding an estimated 1.3 MW at Haines Junction that is not supplied by the grid under N-1) of approximately 109.6 MW in 2023 and 113.3 MW in 2024 (Table 2.2 shows total peak at 119.5 MW for 2023 and 123.2 MW for 2024; the industrial peak at 8.5 MW in 2023 and 8.6 MW in 2024 is removed for this assessment,[25] as well as the assumed 1.3 MW peak load at Haines Junction).
  - In summary, under N-1, there is surplus of dependable capacity of approximately 0.7 MW in 2023 and 0 MW in 2024. Without rented diesel units, the N-1 capacity shortfall would be 35.3 MW in 2023 and 36.0 MW in 2024.

[24] 20 units at 1.8 MW for each unit to total 36 MW for 2024 for N-1 dependable capacity purposes [excluding two spare units].
[25] The forecast industrial peak includes Victoria Gold peak load of 5.5 MW in 2023 and 5.6 MW in 2024, and 3 MW peak load for Hecla Yukon (previously Alexco) in 2023 and 2024.

Table 2.1:
Summary of Customers, Energy Sales and Revenues

Line No.	Description	2021 Approved [2]	2021 Actual	2022 Actual	GRA Forecast 2023 Forecast	GRA Forecast 2024 Forecast
1	**Residential**					
2	Customers	1,780	1,813	1,822	1,858	1,898
3	Sales in MWh	16,210	17,421	17,334	17,693	18,090
4	MWh sales per customer	9.1	9.6	9.5	9.5	9.5
5	Revenue ($000s)	2,384	2,513	2,472	2,532	2,611
6	Cents per KWh	14.7	14.4	14.3	14.3	14.4
7	**General Service**					
8	Customers	514	528	519	529	536
9	Sales in MWh	32,323	29,584	30,662	38,569	44,698
10	MWh sales per customer	62.9	56.0	59.1	72.9	83.4
11	Revenue ($000s)	5,388	4,911	5,005	6,272	7,175
12	Cents per KWh	16.7	16.6	16.3	16.3	16.1
13	**Industrial**					
14	Sales in MWh	102,904	91,143	95,169	75,045	69,368
15	Revenue ($000s)	11,481	11,129	12,206	9,718	8,771
16	Cents per KWh	11.2	12.2	12.8	12.9	12.6
17	**Street lights**					
18	Sales in MWh	168	168	168	168	168
19	Revenue ($000s)	82	82	82	82	82
20	Cents per KWh	48.8	48.8	48.9	48.9	48.9
21	**Space lights**					
22	Sales in MWh	10	9	9	9	9
23	Revenue ($000s)	3	2	2	2	2
24	Cents per KWh	26.6	27.2	27.3	27.3	27.3
25	**Total Company - Firm Retail & Ind.**					
26	Customers	2,293	2,341	2,341	2,387	2,434
27	Sales in MWh	151,614	138,325	143,341	131,484	132,333
28	Revenue ($000s)	19,337	18,638	19,767	18,606	18,642
29	Cents per KWh	12.8	13.5	13.8	14.2	14.1
30	**Wholesale sales**					
31	Sales in MWh	343,537	348,983	346,339	351,291	355,857
32	Revenue ($000s)	28,507	28,959	29,170	29,150	29,529
33	Cents per KWh	8.3	8.3	8.4	8.3	8.3
34	**Total Company - Firm**					
35	Sales in MWh	495,151	487,308	489,680	482,775	488,190
36	Revenue ($000s)	47,844	47,597	48,937	47,756	48,171
37	Cents per KWh	9.7	9.8	10.0	9.9	9.9
38	**Secondary**					
39	Sales in MWh	0	4,739	3,448	2,931	2,931
40	Revenue ($000s)	0	330	365	358	358
41	Cents per KWh	0.0	7.0	10.6	12.2	12.2
42	**Total Company**					
43	Sales in MWh	**495,151**	**492,047**	**493,128**	**485,706**	**491,121**
44	Revenue ($000s)	**47,844**	**47,927**	**49,302**	**48,114**	**48,528**
45	Cents per KWh	**9.7**	**9.7**	**10.0**	**9.9**	**9.9**
46	Rider J ($000s) before 2023/24 GRA	25,036	19,430	26,348	26,265	26,183
47	**Total Sales Revenues[1]**	**72,880**	**67,357**	**75,650**	**74,379**	**74,711**
48	**Total Sales Revenues excluding secondary sales**	**72,880**	**67,027**	**75,285**	**74,021**	**74,353**

Note:
1. Excludes revenues from other revenues.
2. Reflects 2021 GRA Compliance Filing for YUB Order 2022-07 with revised Rider J as per YUB Order 2023-01.

Table 2.2:
Summary of Energy Balance, Losses, and Peak

Line No.	Description	2021 Approved	2021 Actual	2022 Actual	GRA Forecast 2023 Forecast	GRA Forecast 2024 Forecast
	Sales and Losses					
1	Total Energy Sales	495,151	492,047	493,128	485,706	491,121
2	Losses - MWh	43,575	41,326	44,362	42,938	43,219
3	Losses - %	8.8%	8.4%	9.0%	8.8%	8.8%
4	Total Generation	538,726	533,372	537,489	528,644	534,340
5	Secondary Sales Related Generation	0	5,106	3,745	3,190	3,189
6	Firm Load Generation	538,726	528,266	533,744	525,454	531,151
	Actual Generation - MWh					
	Hydro Generation					
7	Whitehorse	259,116	226,420	219,079	280,502	261,359
8	Aishihik	178,146	192,320	192,146	130,161	125,639
9	Mayo	71,201	74,498	80,914	71,595	73,895
10	Total Hydro	508,463	493,239	492,139	482,257	460,893
11	**Wind Turbine**	0	0	0	0	0
12	**IPPs**	2	2	1,952	6,102	16,811
	Diesel Generation[1]					
13	Whitehorse	1,870	14,505	8,405	5,405	7,923
14	Faro	237	2,208	6,319	1,780	2,029
15	Dawson	823	1,798	2,938	987	1,669
16	Mayo	21	77	184	95	183
17	Total Diesel	2,951	18,588	17,846	8,267	11,804
18	**LNG Generation**[1]	27,309	21,545	25,552	32,017	44,833
19	**Total Thermal**[1]	30,260	40,134	43,398	40,285	56,636
	Source - %					
20	**Hydro Generation**	94.4%	92.5%	91.6%	91.2%	86.3%
21	**LNG Generation**	5.1%	4.0%	4.8%	6.1%	8.4%
22	**Diesel Generation**	0.5%	3.5%	3.3%	1.6%	2.2%
23	**IPP Generation**	0.0%	0.0%	0.4%	1.2%	3.1%
	LTA Generation - MWh					
24	**LTA Hydro Generation**	452,796	449,960	453,157	444,871	446,246
25	**LTA Wind Generation**	0	0	0	0	0
26	**IPP Generation**	2	2	1,952	6,102	16,811
27	**LTA Thermal Generation**	85,930	78,306	78,635	74,480	68,095
28	**Total LTA Generation**	538,729	528,269	533,744	525,454	531,151
	Peak - MW[2]					
29	**Integrated System**	112.7	104.4	114.2	119.5	123.2

Notes:

1 Actual thermal generation reflects actual generation required for maintenance, capital, RFID and all other generation, e.g., peaking. Forecast Actual Generation includes peaking, maintenance and capital requirements reflecting short-term hydro generation forecasts.

2 Peak load is a one-hour maximum load on the grid forecast to occur in December (forecasts assume weather normalized temperature) and includes industrial peak.

APPENDIX 2.1
LONG-TERM AVERAGE THERMAL GENERATION CALCULATIONS

APPENDIX 2.1: LONG-TERM AVERAGE THERMAL GENERATION CALCULATIONS

Section 3 of OIC 2021/16 directs that forecast fuel costs to be included in rates for thermal generation to meet forecast customer requirements are to be based on long-term average (LTA) annual renewable resource availability (rather than forecasts of actual hydro generation resulting from actual water conditions). Accordingly, for the purpose of the 2023/24 GRA test years, hydro and thermal generation forecasts are based on LTA water supply for hydro generation as updated with the latest information. The LTA thermal generation calculations also take into account Independent Power Production (IPP) LTA renewable generation forecasts for 2023 and 2024 based on information available at this time.

The determination of LTA annual hydro availability is adjusted as required in each GRA to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.

The forecast 2023 LTA thermal generation is 74.480 GW.h and the forecast 2024 LTA thermal generation is 68.095 GW.h, based on Table 2.1-1 for 2023 and Table 2.1-2 for 2024 developed to determine annual expected YEC thermal generation based on long-term average YEC hydro generation at YEC forecast grid loads (net of expected IPPs and expected Fish Lake generation) ranging from 480 to 580 GW.h/year. The forecast for the test year is based on the following proposed updates to the determination of LTA annual hydro availability for the current GRA:

a) Yukon Energy now has more water year records compared to 2021 GRA [41 water years, from 1981 to 2021, compared to 38 water years, 1981 to 2018, used in 2021 GRA]. This added information has tended to increase LTA hydro estimates.
b) Updated reservoir and generation station water flow requirements changes, including 10-year average for Aishihik Lake spring water levels to reflect water years as noted above.
c) Updated load curves reflecting changes to monthly sales related to non-industrial and industrial load shape and/or volumes.
d) Loads to reflect expected IPPs for 2023 and 2024.
e) Incorporated benefits of Whitehorse Rapids Generating Station Unit #2 Uprate and Unit #4 Servomotor.[1]

[1] In the 2021 GRA, the expected incremental hydraulic generation from WH2 uprate and WH4 servomotor/uprate projects was 4.2 GW.h based on a half-year impact for 2021 [7.1 GWh/year] and was manually adjusted after the model runs [please see 2021 GRA, Appendix 2.1, Table 2.1-1 note #7]. For 2023/24 GRA, YECSIM model inputs are adjusted to reflect the uprate projects and Tables 2.1-1 and 2.1-2 already reflect the incremental hydro generation. The annual expected incremental hydraulic generation is about 6.3 GW.h at 2024 load levels [overall firm generation load in 2024 is lower compared to the 2021 GRA firm load].

Table 2.1-1: Expected Thermal Generation Based on Long-Term Average Hydro Generation (2023)

Line Number	YEC Grid Load Net of IPPs (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	480.0	433.880	46.120			
2	485.0	435.449	49.551	5.0	3.431	69%
3	490.0	436.957	53.043	5.0	3.492	70%
4	495.0	438.410	56.590	5.0	3.547	71%
5	500.0	439.814	60.186	5.0	3.596	72%
6	505.0	441.174	63.826	5.0	3.639	73%
7	510.0	442.496	67.504	5.0	3.678	74%
8	515.0	443.784	71.216	5.0	3.712	74%
9	520.0	445.040	74.960	5.0	3.743	75%
10	525.0	446.269	78.731	5.0	3.771	75%
11	530.0	447.472	82.528	5.0	3.797	76%
12	535.0	448.652	86.348	5.0	3.821	76%
13	540.0	449.808	90.192	5.0	3.844	77%
14	545.0	450.942	94.058	5.0	3.866	77%
15	550.0	452.054	97.946	5.0	3.889	78%
16	555.0	453.142	101.858	5.0	3.912	78%
17	560.0	454.205	105.795	5.0	3.937	79%
18	565.0	455.241	109.759	5.0	3.964	79%
19	570.0	456.248	113.752	5.0	3.993	80%
20	575.0	457.221	117.779	5.0	4.026	81%
21	580.0	458.158	121.842	5.0	4.063	81%

Example
Expected YEC Thermal Generation for the YEC generation at 519.352 GW.h (net of expected IPP & Fish Lake)

Step 1. Find the closest load from Column A that is less than 519.352 GW.h = 515 GW.h (Line 8).

Step 2. Find the thermal generation from Column C = 71.216 GW.h (Line 8).

Step 3. Find the difference between the given load (519.352 GW.h) and load from Step 1 (515 GW.h) = 4.352 GW.h

Step 4. Apply the percentage from Column F (Line 9, 75%) to the difference from Step 3 (4.352 GW.h) = 3.264 GW.h

Step 5. Add numbers from Step 2 (71.216 GW.h) and Step 4 (3.264 GW.h) = 74.480 GW.h

The expected thermal generation at 519.352 GW.h load [net of Fish Lake and IPPs] is 74.480 GW.h.

1. "YEC Grid Load" is the annual YEC generation load on the Integrated Grid net of IPP generation, secondary sales related generation and 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, 41 "water years" on record (1981-2021) and 20 "load years" (each examines a different hypothetical scenario to evaluate generation under different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this removes results distorted by starting or ending year volumes). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.
4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m), current Mayo Lake operation rule (no additional storage, impact of sedimentation at the outlet of Mayo Lake) and restricted Mayo GS winter flows (based on new Mayo Ice Protocol Mayo GS outflows are restricted at max 19 cms in November and 15 cms in December, after which restrictions are relaxed by 1.75 cms/week reaching 20 cms by early January and 24 cms by February [the same as 2021 GRA]).
5. The simulation model results are based on 2023 forecast load and IPP distributions, and requires modifications when new mines, industrial loads or IPP generation are connected to [or disconnected from] the grid.
6. The table assumes max YEC Grid Load (i.e., excluding IPP generation) at 580 GW.h and minimum YEC Grid Load at 480 GW.h. If the YEC Grid Load exceeds these limits then the table needs to be updated.
7. Numbers are subject to rounding.

Table 2.1-2:
Expected Thermal Generation Based on Long-Term Average Hydro Generation (2024)

Line Number	YEC Grid Load Net of IPPs (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	480.0	436.828	43.172			
2	485.0	438.321	46.679	5.0	3.507	70%
3	490.0	439.768	50.232	5.0	3.554	71%
4	495.0	441.171	53.829	5.0	3.596	72%
5	500.0	442.536	57.464	5.0	3.635	73%
6	505.0	443.865	61.135	5.0	3.671	73%
7	510.0	445.160	64.840	5.0	3.704	74%
8	515.0	446.426	68.574	5.0	3.735	75%
9	520.0	447.663	72.337	5.0	3.763	75%
10	525.0	448.873	76.127	5.0	3.790	76%
11	530.0	450.057	79.943	5.0	3.816	76%
12	535.0	451.216	83.784	5.0	3.841	77%
13	540.0	452.351	87.649	5.0	3.865	77%
14	545.0	453.460	91.540	5.0	3.890	78%
15	550.0	454.545	95.455	5.0	3.916	78%
16	555.0	455.603	99.397	5.0	3.942	79%
17	560.0	456.633	103.367	5.0	3.970	79%
18	565.0	457.633	107.367	5.0	4.000	80%
19	570.0	458.601	111.399	5.0	4.032	81%
20	575.0	459.535	115.465	5.0	4.066	81%
21	580.0	460.431	119.569	5.0	4.104	82%

Example
Expected YEC Thermal Generation for the YEC generation at 514.341 GW.h (net of expected IPP & Fish Lake)

Step 1. Find the closest load from Column A that is less than 514.341 GW.h = 510 GW.h (Line 7).

Step 2. Find the thermal generation from Column C = 64.840 GW.h (Line 7).

Step 3. Find the difference between the given load (514.341 GW.h) and load from Step 1 (510 GW.h) = 4.341 GW.h

Step 4. Apply the percentage from Column F (Line 8, 75%) to the difference from Step 3 (4.341 GW.h) = 3.255 GW.h

Step 5. Add numbers from Step 2 (64.840 GW.h) and Step 4 (3.255 GW.h) = 68.095 GW.h

The expected thermal generation at 514.341 GW.h load [net of Fish Lake and IPPs] is 68.095 GW.h.

1. "YEC Grid Load" is the annual YEC generation load on the Integrated Grid net of IPP generation, secondary sales related generation and 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, 41 "water years" on record (1981-2021) and 20 "load years" (each examines a different hypothetical scenario to evaluate generation under different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this removes results distorted by starting or ending year volumes). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.
4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m), current Mayo Lake operation rule (no additional storage, impact of sedimentation at the outlet of Mayo Lake) and restricted Mayo GS winter flows (based on new Mayo Ice Protocol Mayo GS outflows are restricted at max 19 cms in November and 15 cms in December, after which restrictions are relaxed by 1.75 cms/week reaching 20 cms by early January and 24 cms by February [the same as 2021 GRA]).
5. The simulation model results are based on 2024 forecast load and IPP distributions, and requires modifications when new mines, industrial loads or IPP generation are connected to [or disconnected from] the grid.
6. The table assumes max YEC Grid Load (i.e., excluding IPP generation) at 580 GW.h and minimum YEC Grid Load at 480 GW.h. If the YEC Grid Load exceeds these limits then the table needs to be updated.
7. Numbers are subject to rounding.

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 required by the *Rate Policy Directive (1995)*, OIC 1995/90, as amended. 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 the 2023 and 2024 test years, as well as comparative figures for 2021 and 2022 actuals.

There are four major components to Yukon Energy's 2023 and 2024 revenue requirement:

- Fuel and purchased power which include fuel costs for generation as well as power purchase costs, including from Independent Power Producers (IPPs);
- Non-fuel operating and maintenance expenses which include costs related to the production and delivery of energy and administrative costs of support functions;
- 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 2023 and 2024 revenue requirement to the Yukon Utilities Board (YUB) approved (compliance) revenue requirement for the 2021 GRA ("2021 approved"), as well as the 2021 and 2022 actuals.

Actual revenue requirement for 2021 was $71.473 million or 2.4% lower than the approved compliance filing costs of $73.249 million. 2022 actual revenue requirement increased to $75.475 million. The forecast revenue requirements proposed for 2023 in the Application is $81.440 million [$8.191 million or 11.2% higher than the 2021 approved revenue requirement of $73.249 million] and for 2024 is $90.425 million [a further increase of $8.985 million or 11.0% over 2023]. In general, Yukon Energy's forecast 2023 and 2024 revenue requirements primarily reflect proposed adjustments to thermal generation requirements and fuel prices, changes to labour and non-labour costs, and changes to depreciation resulting from the impact of increases in rate base relative to 2021 approved numbers.

Table 3.1:
Yukon Energy Revenue Requirement
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Fuel and Purchased Power	$ 15,882	$ 12,667	$ 15,051	$ 16,272	$ 16,967
Non-Fuel Operating and Maintenance	28,575	28,667	30,828	34,999	37,484
Depreciation and Amortization	12,631	13,692	11,094	11,997	15,161
Return on Rate Base	16,161	16,448	18,503	18,172	20,814
Revenue Requirement/Revenue	$ 73,249	$ 71,473	$ 75,475	$ 81,440	$ 90,425

Fuel and Purchased Power consists of generation fuel cost forecasts based on long-term average hydro generation and forecast loads, cost of fuel required for maintenance purposes and power purchased from ATCO Electric Yukon (AEY) and from Independent Power Producers (IPPs). The forecast Fuel and Purchased Power cost for 2023 reflects an increase of $0.390 million or 2.5% over the 2021 approved cost, and the 2024 forecast reflects a further increase of $0.695 million or 4.3% over the 2023 forecast. This overall increase primarily reflects higher IPP purchases (see Table 2.2) as well as higher fuel prices partially offset by lower long-term average thermal generation (see Section 3.2 for further details).

Non-Fuel Operating and Maintenance cost for 2023 is forecast to increase by $6.424 million or 22.5% over the 2021 approved cost, and the 2024 forecast reflects a further increase of $2.485 million or 7.1% over the 2023 forecast. The increases from the 2021 approved cost reflect higher production and labour costs, including the increase in diesel rental costs required to meet the N-1 single contingency capacity planning criteria.

Forecast Depreciation and Amortization costs for 2023 are $0.635 million or 5.0% lower than the 2021 approved costs, but the 2024 forecast reflects an increase of $3.164 million or 26.4% over the 2023 forecast. The reduction in 2023 reflects additions to net fixed asset depreciation ($0.866 million increase in 2023 over 2021 approved) offset by the reduction in deferred cost amortization ($1.951 million reduction in 2023 over 2021 approved). The subsequent increase in 2024 over 2023 forecast reflects additions to net fixed asset depreciation ($1.406 million increase in 2024 over 2023 forecast) and an increase in deferred cost amortization ($1.937 million reduction in 2024 over 2023 forecast).

The forecast Return on Rate Base for 2023 reflects an increase of 12.4% ($2.012 million) over the 2021 approved amount, and the 2024 forecast reflects a further increase of 14.5% ($2.642 million) over the 2023 forecast. The increase primarily reflects an approximate 7.4% increase in mid-year rate base in 2023 over 2021 approved and a further increase of 13.2% in 2024 over 2023. Yukon Energy's capital structure continues to be financed with 60% long-term debt and 40% equity. The forecast 2023 average cost of long-term debt at 3.31% is 375 basis points higher than the 2021 approved cost at 2.94%, and the forecast for 2024 is 3.43% which is 11 basis points higher than the 2023 forecast primarily reflecting higher interest rates for new debt. The forecast return on equity for both test years is proposed at 8.70%, 5 basis points higher than the 2021 approved rate.

Each of the above categories of the 2023 and 2024 revenue requirements is reviewed in detail below.

3.2 FUEL AND PURCHASED POWER

Fuel and Purchased Power costs as set out in Table 3.2 for the 2023 test year increase to $16.272 million (from $15.882 million in 2021 approved), and further increase to $16.967 million in 2024. The increases for the 2023 and 2024 test years reflect primarily higher fuel prices, as well as increased purchased power cost for IPPs.

Fuel

As reviewed in Section 2.3.2, Yukon Energy's annual fuel costs are based on forecast hydro and thermal generation determined on a long-term average basis. This analysis applies only to firm load requirements. The test year long-term average forecasts for hydro generation have been updated in Appendix 2.1 to reflect current information, and forecast long-term average thermal requirements for the test years are assumed to be supplied with a combination of 90% LNG and 10% diesel generation, the same ratio as approved in the 2021 GRA (see Section 2.3.2). As reviewed in Section 3.6, the Low Water Reserve Fund (LWRF) is assumed to address after each fiscal year end any variance between actual thermal generation and long-term average requirements caused by variations in water supply for hydro generation facilities, and Rider F is assumed to address on a quarterly basis 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 thermal facility fuel use for maintenance.

Table 3.2:
Fuel and Purchased Power
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Fuel	$ 15,829	$ 12,618	$ 14,725	$ 15,122	$ 13,831
Purchased Power	53	49	326	1,150	3,136
Total Fuel and Purchased Power	$ 15,882	$ 12,667	$ 15,051	$ 16,272	$ 16,967

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

As reviewed in Section 2.3.2 and illustrated in Table 3.2.1, forecast long-term average thermal generation is 74.5 GW.h in 2023 and 68.1 GWh in 2024, as compared with 85.9 GW.h in 2021 approved. The fuel cost for forecast long-term average thermal generation is $15.061 million in 2023 and $13.770 million in 2024 before considering forecast fuel costs for thermal maintenance activities.

Forecast thermal consumption for maintenance activities applies to both LNG and diesel generation units: maintenance activities (monthly run-ups) are required for LNG units when the engines have not run for a period of at least two months; diesel run-ups are required in any one month when the engines have not run. For maintenance activities, the forecast diesel unit operation required is 0.198 GWh/year for both test years ($0.061 million, an increase from $0.041 million reflecting higher fuel prices).

Table 3.2.1:
Fuel Cost Comparison: 2021 Approved, 2023 and 2024 Proposed Forecast
($000)

	2021 Approved	2023 With GRA	2024 With GRA
Load net of Fish Lake and IPPs (MW.h)	538,724	519,353	514,342
LTA Thermal Generation (MW.h)	85,930	74,480	68,095
LNG	77,337	67,032	61,286
Diesel	8,593	7,448	6,810
Fuel Prices, $/kW.h			
LNG Price	$0.1814	$0.1906	$0.1906
Weighted Average Diesel price	$0.2051	$0.3069	$0.3069
LTA Fuel Cost, $000	**$15,788**	**$15,061**	**$13,770**
Maintennace run-ups (MW.h)			
Diesel Run-Ups	198	198	198
LNG Run-Ups	-	-	-
Total Maintenance, $000	**$41**	**$61**	**$61**
Total Fuel Cost, $000	**$15,829**	**$15,122**	**$13,831**
Total fuel cost change from 2021 Approved, $000		-$707	-$1,998
Fuel cost change due to LTA thermal volume		-$2,104	-$3,277
Fuel cost change due to fuel price change		$1,397	$1,279

Forecast LNG delivered price to Yukon Energy's Whitehorse thermal facility for the 2023 and 2024 test years is $0.4917 per litre. This forecast for LNG cost reflects contracted liquefaction and shipping costs for 2023, as well as the current market price for commodity value [the actual price for May 1, 2023]. Yukon Energy forecasts average efficiency for LNG generation of 2.58 kW.h/litre, which is the average efficiency for the last three years [2020-2022]. The resulting forecast LNG cost is $0.1906/kW.h. The approved 2021 LNG price was $0.1814/kW.h.

Forecast diesel delivered prices for the 2023 and 2024 test years are $1.1043 per litre for Whitehorse, $1.1415 per litre for Faro, $1.1698 per litre in Dawson and $1.1496 per litre in Mayo, and reflect the most recent diesel prices for YEC as of May 1, 2023. These diesel price forecasts are higher than the 2021 approved diesel prices reflecting increased fuel prices since 2020. Yukon Energy forecast average efficiency for diesel fuel is 3.69 kW.h/litre in Whitehorse, 3.48 kW.h/litre in Faro, 3.78 kW.h/litre in Dawson and 3.70 kW.h/litre in Mayo, and is based on averages for the last three years [2020-2022]. The overall grid efficiency of 3.65 kW.h/litre is an increase from the 2021 GRA, where the approved average efficiency was 3.64 kW.h/litre. The average cost per kW.h of diesel for the purposes of this Application is $0.3069/kW.h compared to $0.2051/kW.h in 2021 approved reflecting higher fuel prices.

Purchased Power

Purchased power costs include power purchased by Yukon Energy from AEY at Marsh Lake Control Structure and Johnson's Crossing. Forecast cost for purchases from AEY is $0.051 million in 2023 and 2024 compared to $0.053 million in 2021 approved.

Purchased power costs also include forecast IPP purchases (see Table 2.2) of 6.102 GWh in 2023 and 16.811 GWh in 2024 under the Yukon government's IPP Policy and OIC 2019/25 (see Section 10 of this Application). The purchase costs for the IPPs in 2023 and 2024 assume the contract purchase prices for the existing IPP contracts [based on the latest approved thermal fuel cost at the time of contract, escalated as per IPP contracts] and 2021 GRA approved thermal fuel cost for new contracts expected in 2023 and 2024.[1] Total IPP purchase cost is forecast at $1.099 million for 2023 [to total power purchase cost of $1.150 million] and $3.085 million for 2024 [to total power purchase cost of $3.136 million].

3.3 NON-FUEL OPERATING AND MAINTENANCE EXPENSES

The total non-fuel operating and maintenance expense approved in the 2021 GRA was $28.575 million, accounting for approximately 39% of the total revenue requirement. As illustrated in Table 3.3, the 2021 actual expenses were close to the approved level [$28.667 million], and 2022 expenses were higher at $30.828 million. Total operating and maintenance costs are forecast in the Application to increase to $34.999 million for 2023 and $37.484 million for 2024. These reflect a $6.424 million increase in 2023 over 2021 approved [22.5% increase] and a further increase of $2.485 million [7.1%] in 2024 over 2023 forecast.

Table 3.3 reports labour expense as a company total; subsequently in this Tab, the labour expenses are broken out by function. In addition to the details below in Section 3.3.1, more labour information is also provided in Schedule 10A of Tab 7 as directed by YUB. An increase in labour expense makes up $2.167 million or 33.7% of the total $6.424 million increase in operating and maintenance expense forecast for 2023 over 2021 approved costs, and $3.063 million, or 34.4%, of the total $8.909 million increase in 2024 over 2021. The average annual compound increase in labour expenses is approximately 7.3% (2024 expenses over 2021 approved) reflecting both the increase in labour rates and number of positions as discussed below in Section 3.3.1.

[1] Standing Offer Program Rules, Section 4.2 (a) state that "the Base Fuel Price is to be equal to the YEC's average blended fuel price per kWh for thermal generation most recently approved by the YUB before the date on which the EPA takes effect". The new contracts in 2023 and 2024 are expected to be finalized before YUB's approval of 2023/24 GRA fuel costs.

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

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Labour	$ 13,016	$ 13,167	$ 13,675	$ 15,183	$ 16,079
Production	5,636	5,285	6,269	7,797	9,491
Transmission	1,394	1,387	1,221	1,159	1,439
Distribution	491	399	516	705	426
General O&M	1,391	1,353	1,408	1,437	1,347
Administration	3,858	4,170	4,505	5,155	4,892
Insurance and Reserve for Injuries/Damages	2,039	2,166	2,491	2,805	3,033
Property Taxes	750	739	743	758	777
Total OM&A (Tab 7, Schedule 10)	$ 28,575	$ 28,667	$ 30,828	$ 34,999	$ 37,484

Non-labour costs are forecast to increase by $4.257 million in 2023 over 2021 approved costs, and to increase by a further $1.589 million in 2024 over 2023 forecast. The average annual compound increase in non-labour expenses is approximately 11.2% (2024 expenses over 2021 approved) primarily due to a $3.3 million increase in diesel rental costs (about 56% of the non-labour increase) required to meet the N-1 single contingency capacity planning criteria.

3.3.1 Labour

Total labour expenditure is made up of labour expense for maintenance and administration and capitalized labour. Capitalized labour is charged to capital projects rather than O&M expenses. It becomes part of revenue requirement through annual depreciation charges incurred after in-service of the related project. Maintenance and administration labour expense is charged directly to revenue requirement. Total maintenance and administration labour expense is forecast to be $15.183 million in 2023 as compared to 2021 approved costs of $13.016 million, reflecting an increase of $2.167 million, and a further increase of $0.896 million in 2024 over 2023 forecast.

Labour expense is generally a function of the following factors:

- **Labour Rates** – This includes factors such as base pay, benefit cost, annual increments (performance increments, cost of living adjustments), etc. This is heavily influenced by collective bargaining agreements (CBA). The last settled CBA expired December 31, 2022. To date, the CBA has not yet been settled for fiscal periods 2023 and 2024. Forecast 2023 and 2024 labour rates are therefore estimated to reflect a negotiated increase in the Yukon Government collective bargaining agreement.
- **Head Count** – This relates to the number of full time equivalent (FTE) positions. The Yukon Energy employee complement is shown in Table 3.4.

Of the total labour expense increase in 2024 from 2021 approved [$3.063 million], approximately $1.859 million (61%) relates to additional headcount and the remaining $1.204 million (39%) relates to labour rate increases and other factors impacting labour costs such as changes in overtime, vacancies and capital allocation.

The labour costs for the 2023 and 2024 test years are net of vacancy factor adjustment of 9 FTEs for each test year based on the 5-year average. The vacancy factor for the 2021 GRA was 5 FTEs excluding 3 new FTEs the YUB directed to remove from the revenue requirements in its Order 2022-03, Appendix A [para 90].

Table 3.4:

Employee Complement History

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
President & Corporate Services	4.16	4.07	3.20	3.10	3.10
Government Relations	1.00	1.00	1.00	1.17	2.00
Business Development			1.00	1.00	1.00
Communications & Customer Service	3.60	3.60	3.60	4.43	3.60
People & Culture	1.00	1.00	1.00	2.00	2.00
Resource Planning, Environment, Health & Safety	8.05	8.04	9.80	10.60	11.13
Finance, Procurement & IT	19.04	19.10	20.13	19.29	20.29
Operations	48.25	49.89	50.74	51.96	53.20
Engineering Services	15.50	15.16	16.56	20.50	23.50
Total	100.60	101.86	107.03	114.05	119.81

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

Table 3.4 shows a forecast cumulative increase of total FTEs of 19.21 from 2021 approved to the 2024 test year. Table 3.4.1 further breaks down the changes.

Table 3.4.1:
Employee Complement Changes from 2021 GRA

President & Corporate Services	
2021 GRA	4.16
VP Business Development transferred to its own department	(1.00)
Reduced Casual	(0.06)
2024 GRA	3.10
Government Relations	
2021 GRA	1.00
New full-time position, Manager Community Relations	1.00
2024 GRA	2.00
Business Development	
2021 GRA	-
VP Business Development transferred to its own department	1.00
2024 GRA	1.00
Communincations	
2021 GRA	1.00
2024 GRA	1.00
Customer Service	
2021 GRA	2.60
2024 GRA	2.60
People & Culture	
2021 GRA	1.00
New full-time position, People & Culture Generalist	1.00
2024 GRA	2.00
Finance, Procurement & Information Technology	
2021 GRA	19.04
New full-time position, Regulatory Planner	1.00
Increased Casual (IT)	0.25
2024 GRA	20.29
Planning, Environment, Health & Safety	
2021 GRA	8.05
New part-time position, EIT DSM	0.45
New full-time position, Regulatory Projects Financial Analyst	1.00
New full-time position, Manager, Planning	1.00
New full-time position, Environmental Complaince PM/Coordinator	1.00
Full-time to part-time, Environment & Resource Analyst	(0.20)
Full-time to part-time, Project Manager	(0.12)
Reduced Casual	(0.05)
2024 GRA	11.13
Operations	
2021 GRA	48.25
Job Planner from Engineering to Operations	1.00
New full-time position, Apprentice Electrician	1.00
New full-time position, Director, Electrical Operations	1.00
New full-time position, Plant Operator	1.00
New full-time position, SCC Operator	1.00
Reduced Casual	(0.05)
2024 GRA	53.20
Engineering	
2021 GRA	15.50
Job Planner from Engineering to Operations	(1.00)
Leave completion, Electrical Engineer	0.50
New term summer students (0.25 x 2)	0.50
New full-time position, Director, Capital Projects	1.00
New full-time position, Sr. Project Manager, Capital Projects	1.00
New full-time position, Junior Project Manager	1.00
New full-time position, Director, Engineering	1.00
New full-time position, EIT - Civil	1.00
New full-time position, EIT - Electrical	1.00
New full-time position, Capital Projects Financial Analyst	1.00
New co-op positions (0.33 / 0.67)	1.00
2024 GRA	23.50
Total 2021 GRA	100.6
Total 2024 GRA	119.8

At historic staff level, it has been Yukon Energy's experience that employees found it difficult to keep pace with increased demands, and that this is becoming an increasing problem as additional assets are added, with increasing resulting burden on staff for planning and executing capital works. In recent years overtime hours have increased creating additional workload and adverse effects for the existing employees which in turn resulted in an increase in employee turnover. The increase in employee turnover has increased the recruiting and relocation costs for the forecast years.

There are a number of corporate factors that directly affect employee complement:

- Increasing assets;

- Strategic importance of improving First Nation and public engagement, relationships and communications;
- Steady growth in customer accounts;
- Increased planning requirements; and
- Continuing high capital demands to maintain existing aging assets.

To combat the above issues, YEC is forecasting an increased employee complement. The increase in employee complement has resulted in a significant decrease in forecast overtime costs as a percent of total labour costs for 2023 and 2024 as compared to the overtime for 2021 and 2022 actual years.[2] Increased employee complement is due to an effort, where possible, to do more work internally as opposed to hiring outside consultants and contractors. YEC has made a conscious effort to limit increases only to those areas where required as reviewed below.

A detailed description of the increases from 2021 approved to the forecast for 2024 is provided below.

- **Government Relations**: Yukon Energy operates electricity generation, transmission and distribution systems across the Yukon on the Traditional Territories of multiple Yukon First Nations. Building and maintaining strong, respectful and productive relationships with Yukon First Nations is critical to the Corporation's ongoing success. Yukon Energy's 5-Year Strategic Plan, published in 2019, confirmed the Corporation's commitment to establishing mutually beneficial and strategic partnerships with Yukon First Nations governments, through respectful and thoughtful collaboration. Specific actions were included in the 5-Year Strategic Plan to develop a framework of partnership options with First Nations, share opportunities for First Nations-owned businesses in Yukon Energy's procurement and project development activities, and create opportunities for Yukon First Nations candidates to join the team. Also, YEC is currently relicensing all of its existing hydro stations concurrently with moving small and large new capacity projects forward. Expanding human resources is critical to building and maintaining relationships that will have a significant impact on the ability to move projects forward successfully while minimizing permitting and regulatory risk. A new position provides necessary

[2] The overtime as percentage of total salaries and wages has reduced from 6.14% actual in 2021 to 5.09% actual in 2022, and forecast to reduce to 4.69% in 2023 and 3.93% in 2024 [2021 approved was 4.72%].

capacity to a small team that is tasked with managing corporate priorities in addition to the day-to-day requirements of communication, customer service, business development, stakeholder, and government partnerships. To facilitate this process, YEC has added the following position:

  - There is a 1.00 position increase in 2024 due to the addition of a Manager Community Relations. This position is expected to be filled in early 2024.

- **People & Culture**: An overall increase in employee complement corporate wide results in an increased People & Culture department workload, along with increased workload resulting from increased recruiting and relocation activities. As a result, YEC considered it necessary to add the following position:

  - There is a 1.00 position increase in 2023 due to the addition of a People & Culture Generalist. This position was filled in 2023.

- **Finance, Procurement & Information Technology**: There has been lack of support from the Yukon Utilities Board and some intervenors regarding consulting costs attributed to YEC regulatory activities such as General Rate Applications. As a result, YEC considered it necessary to add the following position:

  - There is a 1.00 position increase due to the addition of a Regulatory Planner. This position was filled in 2022.

  Also, due to changing technologies and increased reliance on information systems, YEC considered it necessary to add the following position:

  - There is a 0.25 position increase due to the addition of a Casual IT Support. This position is expected to be filled in the last half of 2023.

- **Planning, Environment, Health & Safety**: The operating permits and licences for all three of Yukon Energy's hydroelectric generating stations will expire in the next five years. At risk is 92-97% of our total annual generation capacity and almost all of YEC's own renewable electrical generation. Without this hydro generation, YEC would not be able to generate enough electricity to meet Yukon's electrical needs, and we would not be able to achieve Our Clean Future climate change targets. If there is any gap in licensure for these facilities, Yukon Energy could also lose our encumbering rights to use the water for electricity generation. As we relicense our hydro projects, both environmental and social monitoring requirements are increasing. Based on lessons learned during the Aishihik re-licensing process, we are taking a very different and collaborative approach with affected governments (Yukon First Nations and Yukon) to navigate assessment and permitting/licensing processes. This has increased the complexity and workload to participate and manage these multi-party processes. We are front-end loading our communication and collaboration to decrease timelines and risks in assessment/regulatory processes. We are also re-structuring the department to share responsibilities for re-licensing and monitoring and creating positions focused on actively managing long-term (25-year annual) monitoring costs. As a result, YEC considered it necessary to add the following positions:

- There is a 0.45 position increase due to the creation of a new position, Demand Side Management Engineer-in-Training (EIT). This position is considered necessary as YEC has launched our 2022-2030 Demand Side Management program and this role is the lead for the program. This position was filled in 2022.

- There is a 1.00 position increase due to the creation of a new term position, Regulatory Projects Financial Analyst. This position is considered necessary as a financial budgeting and controls resource across the department as contract values increase, frequency of change orders increase, and all three projects enter re-licensing processes at the same time. This position will also support managing the increasing volume of environmental monitoring consultant contracts. This position was filled in 2023.

- There is a 1.00 position increase due to the creation of a new permanent position, Manager, Planning. This position is considered necessary to support the future-focusing planning division respond to the workload and complexity of hydro relicensing. It will supervise and support a Regulatory Project Manager. This position was filled in 2023.

- There is a 1.00 position increase due to the creation of a new permanent position, Environmental Compliance Project Manager/Coordinator. This position is considered necessary to effectively manage the increasing volume of social and environmental monitoring requirements emerging out of long-term hydro licences. This position was filled 2023.

In addition to the above, the below changes also impact department FTE:

- There is a 0.2 FTE reduction due to Environment & Resource Analyst change from full-time to part-time.
- There is a 0.12 FTE reduction due to Project Manager change from full-time to part-time.
- There is a 0.05 FTE reduction due to reduced Casual support.

- **Operations:** Corporate strategic themes of improvements in reliability, increasing assets, growth in customer accounts and high capital demands to maintain existing aging assets result in the need to enhance the Operations department. From 2021 approved to 2024 forecast the total YEC employee complement increases by 4.95 FTEs due to the following:
  - 1 FTE increase due to Job Planner move from Engineering to Operations;
  - 1 FTE increase due to new full-time position, Apprentice Electrician;
  - 1 FTE increase due to new full-time position, Director, Electrical Operations;
  - 1 FTE increase due to new full-time position, Plant Operator;
  - 1 FTE increase due to new full-time position, SCC Operator; and
  - 0.05 FTE reduction due to reduced Casual.

  In addition to the themes noted above, these positions are considered necessary in an effort to reduce overtime per employee and an effort to do as much work internally as possible as opposed to hiring outside consultants and contractors for all of the additional workload.

- **Engineering Services:** Corporate strategic themes of improvements in reliability, increasing assets, growth in customer accounts and high capital demands to maintain existing aging assets result in an unprecedented capital program. The Engineering Services department's current capacity to deliver the capital program does not align with the planned work needed to deliver on projects required for the utility to meet current and upcoming demands driven by adaptation for climate change, expanding infrastructure to meet increased electricity demand driven by population growth, electrification and a transition to a net zero carbon economy, and revitalization of aging infrastructure. As the Yukon has grown in population and electricity demand has increased the Engineering team has not adequately grown to keep up with the demand and is currently under resourced. YEC considered it necessary to increase the capacity of the department to enable itself to deliver planned work. The increased capacity is focused on two critical areas: engineering and project management. It is also considered important to grow the capacity to delivery on the current and upcoming capital program to ensure YEC has a more stable and effective team. This increased stability would be driven by:

- Having more manageable workloads decreasing stress and turnover;
- Creating redundancy that will decrease the risk associated with unforeseen circumstances within the team; and
- Providing a clear career path and opportunities for advancement.

From 2021 approved to 2024 forecast the total YEC employee complement increases by 8 FTEs due to the following:

- There is a 1.00 FTE decrease as a Job Planner moved from Engineering to Operations.
- 0.5 FTE increase due to Leave completion, Electrical Engineer.
- 0.5 FTE increase due to two new term summer students [0.25 FTE each].
- 1 FTE increase due to new full-time position, Director, Capital Projects. This position was filled in 2023.
- 1 FTE increase due to new full-time position, Junior Project Manager. This position is expected to be filled in the last half of 2023.
- 1 FTE increase due to new full-time position, Director, Engineering. This position was filled in 2023.
- 1 FTE increase due to new full-time position, EIT - Civil. This position was filled in 2023.
- 1 FTE increase due to new full-time position, EIT - Electrical. This position was filled in 2023.

- 1 FTE increase due to new full-time position, Capital Projects Financial Analyst. This position was filled in 2022.

- 1 FTE increase due to new full-time positions and new co-op positions. These positions are expected to be filled in 2024.

In addition to the factors affecting labour listed above, the capital/maintenance forecast allocation also impacts the forecast labour expenses. 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 2021 approved revenue requirement forecasts included an allocation set at 17.2% capital and 82.8% maintenance. For the 2023 test year the forecast allocation is 17.9% capital and 82.1% maintenance and for the 2024 test year the forecast allocation is 18.4% capital and 78.6% maintenance. The ratio is based on YEC's best estimates for each employee's time to perform their job based on corporate goals and expectations and an overall increase in capital projects volumes.

3.3.2 Production

Costs for production consist of labour and non-labour components, excluding fuel and purchased power costs. As set out in Table 3.5, the 2021 approved total production costs were $10.438 million. Total production cost in 2023 is forecast at $13.490 million, an increase of $3.052 million over 2021 approved and a further increase of $2.035 million in 2024 over 2023 forecast.

Table 3.5:
Production Costs
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Labour	$ 4,802	$ 5,076	$ 5,051	$ 5,693	$ 6,034
Diesel	4,028	4,113	4,614	5,639	7,343
LNG	410	85	197	382	407
Hydro	1,082	941	1,064	1,345	1,311
Wind	0	0	0	0	0
Operation Supervision	116	146	394	430	430
Total Production	$ 10,438	$ 10,360	$ 11,320	$ 13,490	$ 15,525

Approximately 29% of the forecast increase in 2023 over 2021 approved for production costs is due to higher labour cost [$0.891 million increase in 2023 forecast over 2021 approved]; approximately 24% of the forecast increase in 2024 over 2021 approved for production costs is due to higher labour cost [$1.233 million increase in 2024 forecast over 2021 approved].

Non-labour production expenses are forecast to increase by $2.161 million in 2023 over 2021 approved and a further increase of $1.694 million in 2024 over 2023. About $3.315 million or 86% of the total $3.855 million increases in non-labour expenses forecast in 2024 over 2021 approved are due to diesel generation related expenses, almost entirely accounted for by increased diesel rental costs.

Diesel Rentals

As reviewed in Section 2.4 of Tab 2, mobile diesels are rented to address dependable capacity shortfalls after consideration of forecast winter peak non-industrial load, dependable capacity forecast to be available at the time of winter peak, and the N-1 standard which determines system capacity assuming the loss of the system's single largest generating or transmission-related generation resource. The 2021 GRA forecast requirement for 1.8 MW diesel rental units was 15 units as approved in 2021, excluding spares; the same 15 units was required in 2022 (i.e., winter 2022/23), and 20 units is forecast for both winter 2023/24 and winter 2024/25, excluding spares (see Section 2.4 of Tab 2).

Diesel rental cost is forecast in the 2023/2024 GRA revenue requirement to increase to $5.004 million in 2023 and to $6.761 million in 2024 as compared to approved 2021 costs of $3.492 million.[3] Forecast mobile diesel costs are based on negotiated contracts with the vendor and reflect both the increased number of rental units (which have increased from 15 to 20 units as of winter 2023/24) as well as the increase in rental unit costs (average cost per rental unit has increased from $0.233 million/unit as approved in 2021 to $0.338 million/unit in 2024). Overall, approximately $2.1 million of the $3.3 million rental cost increase in 2024 compared to 2021 approved is due to price increases and approximately $1.2 million is due to the need for additional rental units.[4]

Based on current information, the forecast diesel rentals as summarized above remain the only feasible option in 2023 and 2024 to ensure sufficient dependable capacity to meet the N-1 dependable capacity requirement during those test years. As reviewed in Section 2.4, the 2024 incremental dependable capacity includes 5 MW of Faro diesel replacements and 0.6 MW of DSM – investments that reduced winter 2024/25 diesel rentals by three units. Additional dependable capacity is forecast to be commissioned during 2024 (i.e., the Battery Energy Storage System (BESS) project, plus 6.5 MW of new diesel at Dawson) – however, pending confirmation before approximately June 2024 of ability to rely on any such new facilities during all of winter 2024/25, YEC must retain diesel rentals as currently planned. New capital facilities to be commissioned in 2024, such as BESS and Dawson diesel replacement, will be included in the 2023/24 GRA revenue requirement rate base only to the extent that diesel rentals for winter 2023/24 and 2024/25 can be reduced.

Appendix 3.1 to this Tab provides a business case assessment for diesel rentals as directed in paragraph 115 of Board Order 2022-03.

Other cost increases include Hydro production cost increase of $0.229 million from 2021 approved to 2024 GRA is primarily due to increased costs for trash rack cleaning and crane inspections and repairs. The cost increase for Operations Supervision of $0.314 million from 2021 approved to 2024 GRA is

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[3] The 2021 approved cost was for 15 rental units (1.8 MW per unit) after the removal of the costs related to two additional units for reliability purposes [YUB Order 2022-03, para 114 directed to remove the cost related to two additional units]. For the 2023/24 and 2024/25 winter seasons YEC is forecast to rent 20 rental units (1.8 MW/unit) plus two additional units for reliability purposes; based on YUB Order 2022-03 the costs related to these additional units for reliability purposes are excluded from 2023 and 2024 revenue requirements although they are rented for reliability purposes.

[4] The diesel rentals are contracted for winter season, i.e., 2022/23, 2023/24 and 2024/25. The revenue requirements for fiscal 2023 include rental costs for Jan-Apr from the 2022/23 rental contract (15 units plus spares) and for December from the 2023/24 rental contract (20 units plus spares); while the revenue requirements for fiscal 2024 include rental costs for Jan-Apr from the 2023/24 rental contract and December from the 2024/25 rental contract (20 units plus spares).

primarily due to subscription and licence fees as well as consulting support for Operations Supervision system software.

3.3.3 Transmission and Distribution

As set out in Table 3.6, total transmission and distribution costs in the 2023 test year are forecast to be at $3.273 million and in the 2024 test year at $3.295 million or $0.107 million above the approved 2021 costs of $3.188 million.

Table 3.6:
Transmission and Distribution Costs
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Labour	$ 1,303	$ 1,346	$ 1,235	$ 1,409	$ 1,430
Brushing Cost	1,388	1,313	1,092	1,368	1,368
Other Non-Labour	498	474	645	497	498
Total T&D	$ 3,188	$ 3,133	$ 2,972	$ 3,273	$ 3,295

Forecast labour costs are expected to increase by $0.106 million in 2023 and by $0.127 million in 2024 from 2021 approved reflecting labour cost changes. Other non-labour costs are forecast approximately at the 2021 approved level.

Table 3.6.1 provides details on the brushing costs and allocations between transmission and distribution. The allocation between transmission and distribution can change annually based on specific needs and is not tied to any specific percent target.

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

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Transmission Brushing	$ 1,175	$ 1,197	$ 976	$ 871	$ 1,160
Distribution Brushing	212	116	204	497	207
% Transmission	85%	91%	83%	64%	85%
% Distribution	15%	9%	17%	36%	15%
Total Brushing Expense	$ 1,388	$ 1,313	$ 1,180	$ 1,368	$ 1,368

Total brushing costs are forecast to decrease by $0.020 million in 2023 and 2024 from 2021 approved. Brushing activities are based on Yukon Energy's brushing policy and brushing plans. Yukon Energy has had 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. 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.

The sections that follow provide a breakdown of transmission and distribution costs between transmission and distribution.

Transmission

The costs are forecast at the transmission and distribution level as reviewed in Table 3.6 with a further breakdown of brushing costs in Table 3.6.1. The allocation of labour costs and other non-labour costs between transmission and distribution is impacted by the allocation of the department's administrative costs.

Table 3.7.1 provides total transmission costs with the 2023 test year forecast at $1.816 million and the 2024 test year forecast at $2.105 million or $0.037 million above the approved 2021 costs of $2.068 million.

Table 3.7.1:
Transmission Costs
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Labour	$ 674	$ 645	$ 548	$ 657	$ 666
Brushing Cost	1,175	1,197	976	871	1,160
Other Non-Labour	219	190	244	288	279
Total Transmission	$ 2,068	$ 2,032	$ 1,769	$ 1,816	$ 2,105

Distribution

Costs of operating and maintaining the distribution system are set out in Table 3.7.2. The total distribution costs for the 2023 test year are forecast at $1.457 million and for the 2024 test year are forecast at $1.190 million or $0.070 million above the approved 2021 costs of $1.120 million.

Table 3.7.2:
Distribution Costs
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Labour	$ 629	$ 701	$ 687	$ 752	$ 764
Brushing Cost	212	116	116	497	207
Other Non-Labour	279	283	400	208	219
Total Distribution	$ 1,120	$ 1,101	$ 1,203	$ 1,457	$ 1,190

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)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Labour	$ 372	$ 275	$ 291	$ 343	$ 350
Transportation	555	521	630	632	632
Maintenance of Company Owned Properties	598	665	696	569	466
SCADA Communication	238	167	82	236	249
Total General O&M	$ 1,763	$ 1,628	$ 1,699	$ 1,780	$ 1,697

Labour costs are forecast to decrease by $0.029 million in 2023 and by $0.022 million in 2024 from 2021 approved.

Total forecast costs in the non-labour General O&M categories in 2023 are $0.046 million higher and 2024 costs are $0.044 million lower than approved 2021 costs of $1.391 million. Transportation expenses are forecast to increase $0.077 million in 2023 and 2024 over 2021 approved. Maintenance of Company Owned Properties is expected to decrease by $0.029 million in 2023 and by $0.132 million in 2024 from the 2021 approved. SCADA Communication expenses are forecast to increase by $0.011 million in 2024 over 2021 approved.

3.3.5 Administration

As shown in Table 3.9, Administration expense is forecast to increase by $2.496 million in 2023 over 2021 approved and by $2.760 million in 2024 over 2021 approved. Labour costs are forecast to increase by $1.199 million in 2023 over 2021 approved and by $1.726 million in 2024 over 2021 approved, reflecting labour cost changes as well as FTE changes noted in Section 3.3.1. Non-labour costs are forecast to increase $1.297 million in 2023 over 2021 approved and by $1.034 million in 2024 over 2021 approved.

Table 3.9:
Administration
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Labour	$ 6,539	$ 6,471	$ 7,098	$ 7,739	$ 8,265
Resource Planning	84	93	191	108	108
Communications	155	134	145	175	175
Customer Accounting	240	202	244	423	356
Environmental Mgmt	535	392	329	819	798
General	790	967	853	852	834
Information Systems	741	1,048	1,135	1,116	1,116
Fish Hatchery	210	240	223	222	222
Safety	226	185	222	207	207
Training	200	121	108	150	150
Recruitment	255	149	554	439	457
Board of Directors	252	305	312	419	311
Union	90	316	99	121	91
Regulatory Affairs	20	11	19	8	11
Material Management	32	-7	49	23	23
Contracting	12	2	8	58	18
Professional Development	15	12	17	15	15
Total Administration	$ 10,397	$ 10,641	$ 11,603	$ 12,893	$ 13,157

The increase in Administration costs reflect ongoing cost pressure in several areas, including:

- Information Systems expenses are forecast to increase by $0.375 million in 2023 over 2021 approved due to increased costs for network circuit costs, managed services costs and software licences. The increase in Information System costs is consistent with increased reliance on technology and the importance of keeping data as safe as possible. The 2024 forecast is expected to be at the 2023 forecast level.

- Environmental Management expenses are forecast to increase by $0.284 million in 2023 over 2021 approved due to increased environmental monitoring activities primarily associated with the renewal of the water licence for the Aishihik Generating Station. The 2024 forecast is expected to be $0.022 million lower than the 2023 forecast level.

- Recruitment expenses are forecast to increase by $0.184 million in 2023 over 2021 approved due to increased costs for labour issues as described in Section 3.3.1. The 2024 forecast is expected further increase by $0.017 million over the 2023 forecast level.

- Customer accounting expenses are forecast to increase by $0.183 million in 2023 over 2021 approved due to increased costs relating to travel and a new customer billing system. The 2024 forecast is expected to be $0.066 million lower than the 2023 forecast level.

- Board of Directors expenses are forecast to increase by $0.167 million (66%) in 2023 over 2021 approved primarily due to costs associated with replacement of the President & CEO position. The 2024 forecast is expected to be $0.108 million lower than the 2023 forecast level.

3.3.6 Insurance and Reserve for Injuries and Damages

Yukon Energy's costs related to insurance and Reserve for Injuries and Damages (RFID) are set out in Table 3.10. Each of these costs is reviewed separately below. For the current GRA, the only cost changes proposed relate to increases in insurance. Increases in RFID annual appropriations are proposed only to the extent accommodated by updates or YUB decisions that reduce other forecast revenue requirements.

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

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Insurance	$ 1,423	$ 1,550	$ 1,875	$ 2,190	$ 2,417
Reserve Appropriation (RFID)	616	616	616	616	616
Total	$ 2,039	$ 2,166	$ 2,491	$ 2,805	$ 3,033

Insurance

Yukon Energy's costs for insurance in 2023 are forecast to increase by $0.766 million above approved 2021 costs of $1.423 million, and are based on the completed 2023 annual renewal process. The insurance cost for 2024 is forecast to increase by $0.227 million over 2023 forecast. Costs in 2023 increased due to mid-year market rate adjustments (overall rate increase of 20.4% on property policy) and increased insured asset value. Insured values are based on replacement cost estimates which are escalated annually and have been significant over the most recent two years. Costs in 2024 increase primarily due to a full year impact of the 2023 rate increase [insurance year cycle is different from YEC's fiscal year]. The market rate increases experienced by YEC as part of 2023 renewals are consistent with peer utilities in Canada.

Yukon Energy has taken the following actions over the previous years in order to keep insurance premiums as low as possible while still providing adequate coverage:

- Engaged an industry leading insurance broker (Aon) to obtain the best results for YEC from the insurance market.
- Hosted Risk Control Engineers from various insures for a site visit at WRGS to demonstrate YEC's operational and maintenance practices.
- Presented to insurers in advance of the 2023 policy renewal (property) to convey YEC's positive risk management practices to underwriters.
- Reduced the participation rate of an insurer on our property program to obtain a lower overall rate increase.
- Actively participated in the Canadian Electricity Risk Managers Committee, a group of risk managers from peer utilities that share industry best practices and relevant insurer or broker issues.
- Increased the deductible on our property policy to limit the rate increase caused by market conditions and recent claims.

RFID

The 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.

As part of the 2021 GRA, the Board approved amortization of the 2020 negative balance over a 10-year period ($0.205 million per year) and an annual appropriation of $0.411 million per year to total annual appropriation of $0.616 million.

As shown in Table 3.11 the 10-year average of charges to the RFID increased to $0.682 million. The large expense in 2022 primarily reflects costs associated with the Whitehorse penstock failure, LNG gearbox failure, Dawson diesel coupling failure, flood mitigation and the Mayo rock slope failure. For the 2023 test year, YEC is forecasting costs of $0.554 million and for 2024 costs of $0.682 million (based on 10-year average).

The ten-year history and average of actual expenses is shown in Table 3.11 below.

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

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10 Year Average
Annual Charges	$404	$196	$193	$1,018	$666	$651	$62	$1,233	$917	$1,478	$682

Table 3.11.1 below shows that the RFID balance owing from customers at the end of 2022 was $3.343 million, reflecting higher costs in the recent 2020-2022 period. The current annual allocation of $0.616 million is retained for the test years to limit the overall rate increase requirement, in effect retaining an RFID balance by the end of 2024 that is close to the 2022 end-of-year RFID balance. In the event that other Application 2024 test year costs are reduced by updates or Board decisions, YEC proposes that the RFID annual appropriation starting in 2023 be increased from $0.616 million/year up to the lesser of (a) a level consistent with the Application's 2024 required rate increase of 14.12% and (b) $1.016 million/year (the level consistent with a normal GRA adjustment to reflect the 10-year average RFID charge plus amortization over 10 years of the opening RFID balance at the start of the first test year).

Table 3.11.1:
RFID Continuity Schedule
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Opening Balance	-$2,048	-$1,756	-$1,953	-$3,343	-$3,281
Annual Appropriation	616	616	616	616	616
Annual Costs	-411	-813	-2,006	-554	-682
Closing Balance	-$1,843	-$1,953	-$3,343	-$3,281	-$3,347

3.3.7 Property Taxes

Yukon Energy's property tax costs reflect payments in lieu made to the municipalities where it operates, and are shown in Table 3.12.

Table 3.12:
Property Taxes
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Property Taxes	$ 750	$ 739	$ 743	$ 758	$ 777

Property taxes are forecast to increase $0.008 million in 2023 over 2021 approved, and a further increase of $0.019 million in 2024 over 2023 forecast due to rate increases and valuation updates.

3.4 RATE BASE, DEPRECIATION AND AMORTIZATION

Yukon Energy's rate base includes investment in assets necessary to provide service to ratepayers, as well as provision for working capital necessary for day-to-day financing of the company operations. 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 capital spending undertaken by Yukon Energy since the 2021 GRA, as well as forecast spending for 2023 and 2024, is provided in Tab 5 of this Application. Table 3.13 provides Net Rate Base at mid-year as approved in 2021, actuals for 2021 and 2022, forecasts for 2023 and 2024 test years.

Table 3.13:
Mid-Year Net Rate Base[5]
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Mid-Year:					
Net plant in service					
Before contributions	$ 484,926	$ 470,798	$ 479,471	$ 507,076	$ 549,096
Less contributions	182,552	176,771	183,565	182,947	181,668
Net plant in service	302,374	294,027	295,906	324,129	367,428
Working capital	7,092	6,925	7,581	8,266	8,576
Net Rate Base	$ 309,466	$ 300,951	$ 303,487	$ 332,396	$ 376,004

Yukon Energy's 2023 mid-year forecast net rate base in this Application is $332.396 million (an increase of $22.930 million or 7.4% from 2021 approved mid-year net rate base of $309.466 million). The forecast mid-year net rate base for 2024 is $376.004 million, an increase of $43.608 million or 13.1% over 2023 forecast. The compounded increase in 2024 over 2021 approved is $66.538 million or 21.5%.

Mid-year net plant in service before contributions, which includes unamortized deferred costs, as well as physical plant net of depreciation, is forecast to increase to $507.1 million in 2023 (a $22.1 million increase over 2021 approved mid-year balance of $484.9 million) and forecast to increase to $549.2 million in 2024 which is a further increase of $42.1 million over 2023 forecast. The major increases over the 2021 approved reflects sustaining capital investments, as well as new supply options to address the capacity gap and future growth and other projects as provided in Tab 5.

Increases in net plant in service since the 2021 GRA reflect the change in contributions for extensions ($182.9 million in 2023 and $181.7 million in 2024 compared to $182.6 million approved in 2021).

[5] Net plant in service includes gross property, plant and equipment plus deferred costs [feasibility, relicensing, regulatory, dam safety] and intangibles, less work in progress, accumulated depreciation and amortization, net customer contributions, and disallowed assets. It also includes other reserves and deferral accounts that increase or reduce the rate base depending on the reserve/deferral account balance [reserve for future removal and site restoration, deferred fire gain, Vegetation Management, Defined Benefit Pension and IPP Cost deferral accounts]. Please see Schedule 1 in Tab 7 for details of the rate base calculation. LWRF is included in rate base calculations for 2021 GRA, and actuals for 2021 and 2022. YEC is proposing to exclude LWRF from the rate base in 2023 and 2024 test years as discussed in this section.

The balance of the change in net rate base from mid-year 2021 approved to mid-year 2023 and 2024 reflects increased working capital ($1.2 million increase in 2023 forecast over 2021 approved of $7.1 million and a further increase of $0.3 million in 2024 over 2023 forecast).

Board Order 2022-03 (Appendix A, para 368) directed YEC, on a go-forward basis, to treat the balance in the LWRF as an offset to rate base. In support of this change in rate base determination as proposed by YEC based on prior GRA approvals, the Board referenced Board Order 1992-1 directing the treatment of low water reserve funds as an offset to rate base. The net impact of this change increased YEC's 2021 mid-year rate base, and reduced YEC's 2022 mid-year rate base.[6]

The 2023/2024 GRA Application applies for a change to this Board direction and removal of this LWRF offset to rate base for the test years based on the following considerations:

- The LWRF exists solely to minimize the effect on ratepayers "that would otherwise be caused by variation in actual renewal source availability, including the variation caused by drought conditions" (OIC 2021/16 as referenced by Board Order 2022-03, Appendix A, para 365), and was not established to provide any role in financing, or providing offsetting contributions, to YEC's rate base. In this regard, the LWRF deferral account is similar to the Deferral Fuel Price Variance Account (DFPVA), and it is not appropriate for either of these deferral accounts to have any impact on YEC rate base determination.

- LWRF use as an offset to YEC rate base introduces new effects on ratepayers caused by variation in actual renewal source availability, contrary to the purpose of the LWRF as established by OIC 2021/16, e.g., under drought conditions the LWRF offset as currently approved by the Board is likely to swing from positive as a reduction in rate base and rates to negative as an addition to rate base and rates (the swing could be from $16 million positive to $16 million negative or net $32 million rate base increase based on the current maximum and minimum balances approved by the YUB).

- Notwithstanding the Board's initial determination in Order 1992-1 to treat low water reserve funds as an offset to rate base, in YEC's 1996/97 GRA (Board Order 1996-7) and all subsequent

[6] LWRF mid-year in 2021 was negative $1.5 million, reflecting the negative LWRF balance of -$4.272 million at the end of 2020 – and this increased the mid-year rate base used to set approved 2021 rates. LWRF year-end balance was $2.744 million for 2021 and $9.895 million for 2022 - and the 2022 mid-year LWRF of $6.3 million therefore reduced 2022 mid-year rate base by this amount.

YEC GRAs until Order 2022-03, the Board has removed any use of the LWRF (or its equivalent, i.e., the DCF) as an offset to YEC rate base. OIC 2021/16 confirms the role of the LWRF as evidenced in these prior Board decisions since the 1996/97 GRA, and the absence of any basis for using the LWRF as an offset to YEC's rate base.

Yukon Energy's forecast proposed 2023 and 2024 expenses related to depreciation of capital assets and amortization of deferred charges is $11.997 million in 2023 and $15.161 million in 2024 as shown in Table 3.14.

Table 3.14:
Depreciation and Amortization
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Fixed Asset Depreciation	$ 13,436	$ 14,927	$ 13,310	$ 14,301	$ 15,707
Less: Contributions	-5,912	-6,085	-5,122	-5,656	-5,834
Less: Amortization of fire insurance recoveries	-262	-262	-262	-262	-262
Less: Disallowed Depreciation	-238	-416	-718	-44	-44
Plus: Amortization of deferred charges	5,608	5,529	3,886	3,657	5,594
Total Depreciation & Amortization	$ 12,631	$ 13,692	$ 11,094	$ 11,997	$ 15,161

Forecast fixed asset depreciation expense in 2023 of $14.301 million and in 2024 of $15.707 million (as compared to $13.436 million in 2021 approved), reflects changes in the assets in service.

As a component of net depreciation costs, the revenue requirement includes substantial credits related to amortization of contributions (customer contributions and contributions from Yukon Development Corporation, Yukon Government and Federal Government). This offset has changed from $5.912 million in 2021 approved to $5.656 million forecast in 2023 and $5.834 million forecast in 2024.

Deferred charges include planning and study costs, regulatory costs and licensing costs related to maintaining licences for YEC's hydro facilities and air emission permits.

Forecast amortization of deferred charges is $3.657 million in 2023 and $5.594 million in 2024, compared to $5.608 million for 2021 approved. This 2024 amount includes amortization of feasibility and relicensing costs ($3.195 million) amortization of regulatory costs ($0.846 million, including $0.250 million hearing reserve annual appropriation), intangibles ($1.281 million), dam safety costs ($0.051 million) and amortization of vegetation management deferral costs ($0.222 million).

3.4.1 Regulatory Deferral Accounts

As per Order 2013-01, Yukon Energy established a hearing cost reserve account. Board Order 2018-10 approved annual appropriation of $0.250 million plus amortization of the 2016 credit balance over a five-year period from 2017 to 2021 years [$0.195 million/year] to a total annual appropriation of $0.055 million. The annual appropriation for 2022 actual and 2023 and 2024 test years is $0.250 million which is at the YUB Order 2018-10 approved level.

The Proposed 2024 column does not include 2023/24 GRA hearing related costs as the costs are included in the hearing reserve after approval by the YUB and YEC does not expect the 2023/24 GRA hearing costs will be approved by the end of 2024. YEC will update the account balance based on information available at the time of compliance filing.

Table 3.14.1 shows the hearing cost reserve account continuity schedule.

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

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Opening Balance	$63	$182	$227	$881	$1,016
Annual Appropriation	-55	-55	-250	-250	-250
Annual Costs	0	101	903	386	0
Closing Balance	$8	$227	$881	$1,016	$766

Board Order 2013-01 required Yukon Energy to create a vegetation management deferral account to defer brushing costs in excess of 2011 actual brushing costs. As part of the 2017/18 GRA, the Board approved amortization of the 2016 balance of $2.215 million over a 10-year period ($0.222 million per year from 2017 through 2026) and directed that deferral of these costs is no longer required. YEC is not proposing any changes for the test years. 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)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Opening Balance	$1,329	$1,329	$1,108	$886	$665
Annual Deferred Costs	0	0	0	0	0
Annual Amortization	-222	-222	-222	-222	-222
Closing Balance	$ 1,108	$ 1,108	$ 886	$ 665	$ 443

Yukon Energy maintains a provision for future removal and site restoration costs 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 directed Yukon Energy to notify intervenors and interested parties when the balance of the provision reaches $2.0 million.

Table 3.14.3 provides the continuity schedule of the reserve for site restoration. The costs in 2023 are primarily for final site restoration costs at Haeckel Hill where YEC previously had wind generation assets. This reserve is forecast to fall below $2 million for the first time during the test years.[7] YEC is not proposing any changes for the test years.

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

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Opening Balance	$2,790	$2,738	$2,738	$2,689	$1,966
Annual Appropriation	0	0	0	0	0
Annual Costs	0	0	-49	-723	0
Closing Balance	$ 2,790	$ 2,738	$ 2,689	$ 1,966	$ 1,966

Board Order 2022-03 approved Defined Pension Deferral Account to defer any variances between approved defined benefit pension plan expense in the test year and actuals. Table 3.14.4 provides a continuity schedule for this deferral account. The addition of $0.047 million and -$0.109 million reflect the variances between the approved amount of $0.720 million included in the 2021 labour cost and actual

[7] Board Order 2005-12 directed that the provision in this reserve is not to exceed the cumulative value of the provision at December 31, 2004 of $5.757 million, and that YEC is to notify intervenors and interested parties when the balance declines to $2.000 million.

amounts of $0.767 million for 2021 and $0.611 million for 2022. YEC is not proposing amortization of the deferral account balance at this time as the balance is not significant.

Table 3.14.4:
Defined Pension Deferral Account Continuity Schedule
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Opening Balance	$0	$0	$47	-$62	-$62
Additions	0	47	-109	0	0
Annual Amortization	0	0	0	0	0
Closing Balance	0	47	-62	-62	-62

As noted in Section 3.6.4, based on Order in Council (OIC) 2019/25 YEC has created a deferral account that defers the variances between approved power purchase costs in rates and actual purchase costs [capital related costs are recovered through depreciation expense and rate base].

On a long-term average basis, using the LTA thermal calculation table from the 2021 GRA, YEC estimated the IPP purchases of $0.313 million in 2022 resulted in a $0.286 million reduction of thermal costs [please see Section 3.6.4 for details]. Therefore, the net addition for 2022 is $0.026 million as shown in Table 3.14.5. YEC is not proposing amortization of the deferral account balance at this time as the balance is not significant.

Table 3.14.5:
Proposed IPP Purchase Cost Deferral Account Continuity Schedule
($000)

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Opening Balance	$0	$0	$0	$26	$26
Additions	0	0	26	0	0
Annual Amortization	0	0	0	0	0
Closing Balance	$ -	$ -	$ 26	$ 26	$ 26

3.5 RETURN ON RATE BASE (INTEREST COSTS AND ROE)

The total forecast return on Yukon Energy's mid-year net rate base for 2023 is $18.172 million and $20.822 million for 2024 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 5.47% for 2023 and 5.54% for 2024. This reflects changes to the average interest rate on debt as well as return on equity. Yukon Energy is not proposing a change to capital structure (60% debt and 40% equity), but proposing to change the return on equity from 8.65% approved in the 2021 GRA to 8.70%.

Table 3.15:
Cost of Capital

	Approved 2021	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Average Cost of Debt	2.94%	2.93%	2.89%	3.31%	3.43%
Return on Equity	8.65%	8.93%	10.17%	8.70%	8.70%
Average Cost of Capital	5.22%	5.42%	6.10%	5.47%	5.54%

Yukon Energy's forecast mid-year capital structure for 2023 is comprised of $199.4 million in long-term debt and $132.9 million in common equity, and $225.6 million in long-term debt and $150.4 million in common equity for 2024 (see Schedule 4 of Tab 7).

3.5.1 Costs of Debt

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

- Yukon Development Corporation Debt ($55.620 million): $92.458 million original debt bearing interest at 2.68%, payable monthly with annual principal payments.

- TD Bank Interest Rate Swap ($19.403 million): bearing interest at 3.40%, payable monthly with monthly principal payments.

- Yukon Development Corporation Mayo B Promissory Note ($17.520 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.

  If the load is in the range between Maximum Grid Load and Minimum Grid Load then interest expense is calculated as follows:

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

- Yukon Development Corporation Term Note ($13.430 million): $20.984 million original debt bearing interest at 2.21%, payable annually with annual principal payments.
- Yukon Development Corporation Term Note ($12.136 million): $12.136 million original debt bearing interest at 2.95%, payable monthly with no annual principal payments.
- TD Bank Interest Rate Swap ($6.552 million): $11.0 million original debt bearing interest at 2.06%, payable monthly with monthly principal payments.
- Yukon Development Corporation Term Note ($5.505 million): $5.505 million original debt bearing interest at 2.40%, payable monthly with no annual principal payments.
- TD Bank Interest Rate Swap ($5.659 million): $6.688 million original debt bearing interest at 2.64%, payable monthly with monthly principal payments.
- Yukon Development Corporation Term Note ($2.871 million): $2.871 million original debt bearing interest at 2.899%, payable monthly with no annual principal payments.
- TD Bank Interest Rate Swap ($4.175 million): $4.8 million original debt bearing interest at 2.06%, payable monthly with monthly principal payments.
- Yukon Development Corporation Term Note ($3.959 million): $3.959 million original debt bearing interest at 1.56%, payable monthly with no annual principal payments.
- TD Bank Interest Rate Swap ($6.850 million): $7.7 million original debt bearing interest at 2.88%, payable monthly with monthly principal payments.
- TD Bank Interest Rate Swap ($17.269 million): $17.9 million original debt bearing interest at 4.047%, payable monthly with monthly principal payments.

In order to maintain the 60% debt component of the capital structure as well as finance capital projects, Yukon Energy forecasts additional long-term debt of $34.679 million in 2023 and $26.738 million in 2024, at a rate of 4.23%. As per Board Order 2018-10, the interest rate on new test year debt is a formulaic approach based on the long-term Canada Bonds rate plus 120 basis points (Government of Canada Long-Term Bond Benchmark at 3.03% as of March 30, 2023).

3.5.2 Return on Common Equity

As reviewed in Tab 8, Yukon Energy has reviewed its forecast Return on Equity (ROE) based on the methods and approach approved by the Board in previous GRAs. As reviewed in Tab 8, Yukon Energy's forecast return on equity for the 2023 and 2024 test years is 8.70%.

The following are specifically noted regarding the basis for Yukon Energy's return on equity:

- **Low Risk Utility Benchmark:** The Board continues to approve use of the British Columbia Utilities Commission (BCUC) benchmark utility ROE as the base for determining the ROE for Yukon utilities. The current BCUC benchmark ROE continues to be 8.75%. In 2021, the BCUC initiated a new generic cost of capital proceeding to determine a benchmark utility (or utilities) and a benchmark rate of return. The proceeding is still ongoing with a decision pending. Yukon Energy will update the benchmark ROE when the BCUC has its final decision on this proceeding.

- **Risk Premium Adder for YEC:** Order 2018-10 established a 45 basis point risk premium for YEC over the BCUC benchmark ROE. A 45 basis point risk premium for YEC was considered to be fair and reasonable based on: (1) recognition of small size and principles established for AEY in Order 2017-01;[8] and (2) recognition of YEC risk related to generation, isolated grid, and customer diversity.[9] The Board Oder 2023-01, Appendix A continued using 45 basis points which includes 25 basis points for small size and 20 basis points to recognize risks for generation, isolated grid and customer diversity, but reduced it by 5 basis points "due to changes in risks since Decision 2018-10".[10] As reviewed in Tab 8, YEC is proposing a risk premium of 45 basis points for Yukon Energy for 2023 and 2024 test years to reflect YEC's overall risks continuing to be greater than FortisBC (Electric) as well as AEY.[11]

As required by Section 2 of the *Rate Policy Directive (1995)*, for each test year, Yukon Energy's allowed ROE must be set equal to the Yukon Energy fair return on common equity less 50 basis points (0.5%).

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[8] Decision 2017-01, which established a 25 basis point risk premium for AEY relative to the BCUC benchmark utility. The 25 basis point risk premium was awarded to recognize AEY's small size. This is also applicable to Yukon Energy.

[9] The Board awarded Yukon Energy an additional 20 basis point risk premium (for a total risk premium of 45 basis points above the BCUC benchmark utility) in recognition of YEC specific risks related to generation, isolated grid and customer diversity. The Board indicated that the additional 20 basis points acknowledges the overall risk of YEC as being greater than that of FortisBC (Electric) as well as AEY.

[10] Appendix A, Board Order 2023-01, footnote 34.

[11] Tab 8 notes that AEY's 2023/24 GRA application is seeking a risk premium of 75 basis points above the BCUC benchmark based on changes in its risk profile (an increase over the 25 basis points previously awarded to AEY in the 2016/17 GRA). Tab 8 notes that Yukon Energy's risk continues to be higher than AEY's.

Accordingly, the Yukon Energy proposed ROE in this Application for each test year is 8.70% (8.75% +0.45% - 0.50%).

3.6 STABILIZATION MECHANISMS

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

- Rider F;
- Low Water Reserve Fund (LWRF); and
- Defined benefit pension deferral account.

Yukon Energy is also seeking Board's approval of IPP Purchase Cost Deferral Account that captures variances in forecast costs for the test year and actual costs between test years as reviewed in Section 3.6.4.

3.6.1 Rider F

The Deferred Fuel Price Variance Account (DFPVA) and Rider F are established and maintained pursuant to the *Rate Policy Directive (1995)*, Section 8. This account captures all variations in fuel price per litre for each actual litre consumed, compared to the most recent GRA approved fuel prices. Pursuant to Order 2005-12, Yukon Energy also credits this account with all variations (positive and negative) in the ongoing quarterly adjustment to the prices of secondary sales, compared to the most recent GRA-approved price.

OIC 2018/220 has also amended Section 8 of *Rate Policy Directive (1995)* to replace the expression "diesel fuel" with "diesel fuel and natural gas". In Order 2018-10 the Board approved YEC's 2017/18 GRA request to incorporate references to LNG pricing in the Rider F policy, noting that it was reasonable for YEC to defer variances with respect to LNG prices to the DFPVA and to include deferred LNG price variances in the amounts collected (or refunded) to customers through Rider F. The Board also noted that the addition of a different thermal fuel was not contrary to the purpose of this deferral account, and consistent with the reasons for establishing such a deferral account.

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.

3.6.2 Low Water Reserve Fund (LWRF)

The Low Water Reserve Fund (LWRF), previously called the Diesel Contingency Fund (DCF), is a long established deferral account that operates to smooth customer rate changes from thermal (diesel, LNG and other thermal) generation cost impacts caused by fluctuation of hydro or other renewable generation due to changes in water conditions or changes from long-term average available of other renewable sources.

The LWRF Term Sheet, revised as per OIC 2019/16 requirements and provided in Appendix 2.1 of YEC's 2021 GRA Compliance Filing, was approved by Board Order 2022-07 and is retained without change in the current Application. The LWRF Term Sheet includes provisions regarding interest payments or charges on LWRF balances based on short/intermediate term bond rates and lowest short-term borrowing rates available to YEC.

The current Application addresses the LTA generation forecast as part of Tab 2 sales and generation forecasts (see Appendix 2.1).

3.6.3 Defined Benefit Pension Deferral Account

Board Order 2022-03 approved the Defined Pension Deferral Account to defer any variances between approved defined benefit pension plan expense in the test year and actuals. Table 3.14.4 in Section 3.4.1 provides a continuity schedule for this deferral account.

3.6.4 IPP Purchase Cost Deferral Account

As reviewed below, YEC has created a deferral account to comply with OIC 2019/25 requirements that defers the variances between approved power purchase costs in rates and actual purchase costs [capital related costs are recovered through depreciation expense and rate base].

Section 2 of Order in Council (OIC) 2019/25, *Direction to the Yukon Utilities Board (Independent Power Production Regulation)*, requires the Board to allow the utility to recover the cost of purchasing electricity under an electricity purchase agreement, as well as third party consultant costs (including legal fees) incurred by the utility in relation to the development and implementation of the agreement, and the cost of maintaining or replacing equipment of infrastructure necessary to purchase electricity under the agreement.

Subsection 3(1) of OIC 2019/25 states that the price for a kWh under an "on-grid" purchase is to be based on utility's "average blended fuel price per kWh for thermal generation most recently approved by the board before the date in which the agreement takes effect" and subsection 4(3) states that the purchase price is increased each year by 50% of the Consumer Price Index (CPI).

These OIC requirements apply each year, regardless of whether YEC has been able to address specific adjustments needed in rates through a GRA process. Accordingly, a deferral account mechanism is needed to deal with variances that arise between YEC's costs incurred and its ability to recover these costs through rates.

The relevant issues are demonstrated by the 2021 GRA which included 2 MWh IPP purchases with a total cost of less than $400 [April 14, 2022 Compliance Filing, Table 1.1-1] based on actuals for 2021. The actual cost of IPP purchases in 2022 was at $0.313 million or $0.312 million higher than the cost included in the rates. As the number of IPP connections is evolving after 2021, the volume and the price of the IPP purchases will continue to change annually compared to what is approved in the rates.

Although the IPP generation is predominantly in summer months, on a long-term average basis there are some benefits from IPPs to reduce thermal generation [accumulation of benefits from drought years]. Therefore, YEC is proposing to include IPP long-term average (LTA) thermal displacement benefits related to the IPP purchase volume variances in the deferral account as an offset to the power purchase cost variance.

On a long-term average basis, using LTA thermal calculation table from 2021 GRA, YEC estimated the IPP purchases in 2022 resulted in a $0.286 million reduction of LTA thermal costs as reviewed in Table 3.16.[12] Therefore, the net addition to the deferral account in 2022 is $0.026 million.

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[12] This 2022 assessment likely overstates the IPP LTA benefits as the 2021 GRA LTA thermal calculation table only assumed 2 MWh IPP purchases. The deferral account assessments are relevant when applied to expected future IPP purchases that involve material IPP volumes.

Table 3.16:

IPP LTA Thermal Displacement Benefits for 2022

($000)[13]

		2022 Actual IPP	2021 GRA Approved IPP	Variance
A	IPP Purchases, MWh	1,952	2	1,950
B	**IPP Purchase Cost, $000**	**313**	**0.4**	**312**
C	LTA thermal as % of Incremental Load [LWRF 2022 Annual Report, Attachment 1, Table 1-1]			81%
D=A*C	Calculated IPP LTA Thermal benefits, MWh			1,579
D1	Diesel			0
D2	LNG			1,579
E=D*Fuel Cost	Calculated IPP LTA Thermal benefits, $000			**286**
F=B-E	Net Transfer to IPP Deferral Account, $000			**26**

In contrast to the 2022 situation, the overall IPP LTA thermal displacement benefits for 2023/24 GRA load is 59% of IPP purchases which is the variance of LTA thermal with and without IPPs.

Considering the above, YEC is requesting approval of IPP Purchase Cost Deferral Account that captures variances in IPP purchase costs included in the test year revenue requirements and actual purchase costs offset by IPP LTA thermal displacement benefits calculated as per above example using 59% LTA thermal displacement benefits.

[13] The LTA % for the incremental load as per LWRF 2022 Annual Report, Attachment, Table 1-1 reflects the incremental LTA thermal for added load [supporting table noted as "LTA Thermal Calculations for 2022 for Line 14 in Table 1-1"]. This overstates the IPP LTA thermal displacement benefits as the 2021 GRA LTA thermal calculation table [2021 GRA, Appendix 2.1 revised compliance filing] only included 2 MWh IPP purchases and no percentages were provided with and without IPPs. The table assumes 100% LNG which is the percentage for the LWRF transfer in 2022 as per 2022 LWRF Annual Report.

APPENDIX 3.1
DIESEL RENTAL BUSINESS CASE

APPENDIX 3.1: DIESEL RENTAL BUSINESS CASE

Appendix A of Board Order 2022-03, paragraph 115, provided the following direction for YEC to provide a diesel rental business case in its next GRA:

> *"The Board directs YEC to provide a specific business case going forward for the diesel units (rental, lease and own/resale), other alternatives to rentals and stronger emphasis to least-cost options, the rationale for the options and the timing to implement such options. Of particular interest to assist in evaluating comparisons of Levelized Costs of Capacity would be a sensitivity analysis that includes delays in planned permanent renewable capacity projects and higher-than-forecast peak demand growth over the next 10 years. The Board directs YEC to provide a business case that conforms with these business case criteria in its next GRA".*

In accordance with this direction, YEC has considered the following possible alternatives to the proposed short-term rental of twenty 1.8 MW diesel rental units (excluding spares) for the purpose of meeting the N-1 dependable capacity criteria requirement during winter 2023/24 and winter 2024/25:

- Purchase of diesel rental units, and subsequent resale of those units when they are no longer needed (i.e., the "own/resale" option described above);
- Longer term "lease" of diesel rental units, instead of the short-term rental of diesel units proposed by YEC (i.e., rentals for less than five months during a winter season); and
- Reliance on the addition of new capital facilities that are forecast to be commissioned during the GRA test years, including both the Battery Energy Storage System (BESS) project and the 6.5 MW of new permanent diesel capacity at Dawson that are forecast to be commissioned in 2024.

In considering the short-term rental and longer-term lease or "own/resale" alternatives, it is necessary to distinguish between the need for diesel units to satisfy the N-1 dependable capacity requirement during the 2023/2024 GRA test years, versus YEC's ongoing planning to address future dependable capacity requirements in the longer term. Diesel rentals are proposed to address short-term requirements during the test years, and not as a long-term plan for providing YEC's required dependable capacity.

Summary Overview of Business Case Assessment

As outlined further below, YEC has concluded that neither the "own/resale" option nor the longer-term "lease" option is a feasible alternative to the proposed short-term rental of diesel units for the test years.

With respect to the addition of new capital facilities, YEC projection of a dependable capacity shortfall of approximately 36 MW for winter 2023/24 and winter 2024/25 takes into account the 5 MW of Faro diesel replacements and 0.6 MW of DSM, both of which are included in the 2024 incremental dependable capacity. As reviewed in Section 2.4, these investments reduce the need for diesel rentals in winter 2024/25 by three units. However, as outlined further below, YEC's ability to rely on either or both of the proposed BESS project or the proposed new diesel capacity in Dawson for the purpose of meeting the N-1 dependable capacity criteria requirements cannot be confirmed at this time. Pending confirmation before approximately June 2024 of ability to rely on any such new facilities during all of winter 2024/25, it therefore continues to be necessary today for YEC to retain diesel rentals as currently planned to ensure adequate dependable capacity for winter 2024/25.

With respect to YEC's ongoing dependable capacity planning, as outlined further below, YEC's current plans will reduce its future reliance on diesel rentals through its longer-term advancements in developing new thermal facilities, the BESS project, the Atlin Hydro Expansion EPA, and dependable capacity DSM development. These developments do not, however, alleviate the short-term need for diesel rentals as currently planned for the purpose of meeting the N-1 dependable capacity criteria requirements for winter 2023/24 and winter 2024/25.

2023/24 GRA Diesel Rentals

Based on current information, the forecast diesel rentals as summarized in Tab 3, Section 3.3.2 of this Application remain the only feasible option for winter 2023/24 and winter 2024/25 to ensure sufficient dependable capacity to meet the N-1 dependable capacity requirement.

Diesel infrastructure at Whitehorse, Faro and Mayo has been or is being established to accommodate the needed modular diesel units. New permanent modular diesel thermal capacity is being developed as quickly as feasible – and this work has demonstrated the time needed for YEC to purchase and install new modular diesel facilities. Rental of available units is the only option at this time to meet remaining forecast shortfalls in required dependable capacity for winter 2023/24 and winter 2024/25. The following points provide related details:

- As reviewed in Tab 2, Section 2.4 of this Application, YEC's existing and planned dependable capacity facilities and DSM result in a shortfall of approximately 36 MW in meeting N-1 dependable capacity criteria requirements during winter 2023/24 and winter 2024/25.

- The winter 2024/25 incremental dependable capacity includes 5 MW of new Faro diesel replacements and 0.6 MW of DSM – investments that reduced required winter 2024/25 diesel rentals by three units. However, due to the increase in non-industrial peak in 2024/25 over 2023/24 and diesel retirements noted in Tab 2, section 2.4, the dependable capacity shortfall is being addressed by the twenty 1.8 MW diesel rental units forecast for the two test year revenue requirements.

- Additional new dependable capacity is forecast to be commissioned during 2024 (i.e., the Battery Energy Storage System (BESS) project, plus 6.5 MW of new diesel at Dawson) – however, pending confirmation before approximately June 2024 of ability to rely on any such new facilities during all of winter 2024/25, YEC must retain diesel rentals as currently planned to ensure adequate dependable capacity for winter 2024/25. The Application assumes that both BESS and Dawson diesel replacement projects remain in WIP, and YEC will continue to assess applicable options during 2024. New capital facilities commissioned in 2024 will be included in the 2023/24 GRA revenue requirement rate base only to the extent that diesel rentals for winter 2023/24 and 2024/25 can be reduced.

During the review of YEC's 2021 GRA, YEC explained why trading diesel engines [i.e., purchasing diesel rental units and sale later when it is not needed] is not considered to be a feasible option for YEC.[1] The following key factors are noted specifically with regard to the 2023 and 2024 test years:

- The diesel units being rented are the only known rental option available to YEC, and these units are not considered acceptable options for purchase by YEC – this equipment would not be considered prudent for capital level spending by YEC. Accordingly, there is no acceptable purchase option relating to the units being rented.

- The purchase option for new diesels is only available subject to the time needed to complete required prudent planning and implementation activities, i.e., YEC is already making maximum use of new purchase diesels to displace the need for rental diesels in the test years.

- As demonstrated by YEC's ongoing planning to purchase new diesels, prudent expenditure of the required additional capital funds for any such purchase has been confirmed to require considerable time compared for design, procurement and installation.

- As indicated for the test years, delays in commissioning the BESS and 11.5 MW of new diesels committed at Dawson and Whitehorse have materially increased the 2024 diesel rental requirement.

[1] See September 29, 2021 hearing transcript, line 16 at page 460 to line 21 at page 463.

- Furthermore, at time of such purchase, there is no apparent feasible option to lock down a time and acceptable price for future sale of the new unit. YEC can of course in the future assess options for such diesel unit sales in the event that it sees no further need for the units – but this potential future option does not affect the short-term need for rentals to accommodate time delays needed for new permanent diesel units.

- Due to fast-changing environmental regulations focused on net-zero electricity systems and other climate change initiatives, the diesel units purchased today based on an assumed future unconfirmed sale may be very difficult to market in future at any acceptable price.

Short-term diesel rental has to date resulted in lower GRA revenue requirements in the near term than would be feasible with new capital facility options (see next section below). The cost-saving benefits from capital cost options versus short-term rental options typically require longer-term consideration over the life of the new facilities. Short-term rentals enable YEC to plan as effectively as possible for longer-term development, including adapting to changing circumstances as they occur.

With respect to the further alternative of a longer-term lease of diesel rental units, instead of short-term rentals during the winter months of the test years, YEC has concluded that this is not a viable or prudent option. YEC's requirement related to the N-1 dependable capacity shortfall exists only during the winter season. Short-term rentals are for about four and a half months, from the start of December to mid-April. YEC has no interest and sees no value in paying for a lease of these units year-round, beyond the winter season when the units are actually needed to meet the N-1 dependable capacity shortfall.

When assessing rentals, YEC has traditionally seen no value in seeking contract durations beyond a few months, and YEC sees no reason to revisit that view:

- Short-term contracts allow YEC to adapt as needed to changing conditions and requirements for future winter seasons. Experience has demonstrated the value in retaining this flexibility.

- Under IFRS 16, an agreement extending beyond 12 months would have to be recorded as an asset in YEC's books, which would add costs and issues without value to YEC.

- The purchase option has traditionally been more cost effective for utilities such as YEC than considering a lease option to serve longer-term diesel generation requirements.

Ongoing YEC Dependable Capacity Planning

In addition to considering the short-term need to retain diesel rentals to meet the N-1 dependable capacity criteria requirements in winter 2023/24 and winter 2024/25, YEC has also reviewed its ongoing, long-term dependable capacity planning options in response to the Board's direction.

YEC has recently reviewed longer-term dependable capacity planning options with the YUB during the 2021 GRA, the Battery Part 3 proceeding, and the Atlin EPA proceeding. In the context of ongoing dependable capacity planning, rental diesels are expected to continue providing short-term dependable capacity as and when required for the same business case reasons noted above for the current GRA test years, with adjustments to be made in future occurs due to the addition of new permanent dependable capacity developments as well as future changes in forecast peak loads.

Dependable capacity shortfalls were forecast in the 2016 Integrated Resource Plan, based on expected future non-industrial peak load growth and the need to replace aging diesel infrastructure. After considerable planning and public review, and based on the Yukon Government's climate change objectives, the option of developing one new large diesel facility was discarded by YEC and replaced by YEC's 10-Year Renewable Electricity Plan (10-Year Plan) that includes new thermal replacements at YEC's different thermal facilities, the Atlin Hydro Expansion project EPA, the BESS project, dependable DSM capacity development, and the review of large renewable dependable capacity and energy options such as Tutshi-Moon Pumped Storage Hydro.

The 2023/24 GRA confirms YEC advancement in developing new thermal facilities (see Appendix 5.1A – Thermal Replacement (16.5 MW)), the BESS project (Table 5.7 confirms ongoing cost in WIP), the Atlin Hydro Expansion EPA (amendments to the EPA have extended condition precedent timelines to October 31, 2023 to facilitate funding discussions), and dependable capacity DSM development (see Appendix - 5.2A). Thermal infrastructure is being developed at each YEC thermal facility – recognizing that modular units are now the cost effective option in each location, whether for rentals or permanent units. Thermal developments also recognize the broader benefits for community energy security of having adequate dependable thermal capacity at Dawson City as well as other non-Whitehorse communities served by YEC, and of other related thermal infrastructure improvements in these communities.

The following summaries are noted on the Levelized Cost of Capacity (LCOC) being reported in the current GRA for new diesel and dependable DSM projects – the analysis confirms longer-term cost savings from these projects compared with rental diesels, while also showing that short-term diesel rental costs (e.g., 10-years) are likely to remain competitive:

- The LCOC over a 40-year life for the 5 MW diesel replacement at Faro at $192.17 per kW-yr (2024$) is lower than the LCOC of $255 to $299 per kW-yr for 2024 rental diesel cost at Faro and $216 to $252 per kW-yr for all YEC 2024 diesel rental costs (assuming a 40-year life and excluding rental capital infrastructure costs).[2]

- All programs in the DSM Portfolio for dependable capacity (see Appendix 5.2A in this Application) have a LCOC significantly lower than YEC's current marginal source (rental diesel, new diesel replacement).

- Diesel rental 2024 LCOC for the 10-year period relevant for comparison with DSM programs are much lower than when assessed over 40 years, ranging from $194/kW-yr to $202/kW-yr for average rental costs and from $230 to $239/kW-yr for current Faro diesel rentals.[3]

Although thermal dependable capacity continues to play a vital role in the isolated Yukon Grid under the 10-Year Plan, YEC also recognizes a need to focus on building permanent renewable dependable capacity where this is feasible. In this regard, YEC's 10-Year Plan specifically noted Yukon's Our Clean Future strategy stating that the Yukon government will develop legislation by 2023 to require at least 93% of the electricity generated on the Yukon Integrated System to come from renewable sources. The BESS project, Atlin Hydro EPA, and dependable capacity DSM spending all contribute to these renewable requirements.

Subject to securing local First Nation support, permitting, and needed federal funding, the Tutshi-Moon Pumped Storage Hydro project has been selected to provide a significant increase in renewable dependable capacity to address Yukon's existing and forecast capacity shortfall. It also presents an opportunity to use surplus summer renewable energy to meet the forecast winter energy shortfall.

YEC is currently completing a review and update of the 10-Year Renewable Electricity Plan to take into account ongoing changes, including delays expected in development of the Atlin Hydro Expansion EPA and the Tutshi-Moon Pumped Storage Hydro project. Sensitivities will examine options to address those delays as well as options to address higher-than-expected growth in peak demand over the next decade.

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[2] LCOC assessed assuming $220.41 Faro site rental cost per kW in year 1 with escalation in range of 3% to 4%/yr, 40 year project life and YEC WACC for new rate base of 6.018%/year per 2024 GRA (60% new debt financed at 4.23% and 40% equity financed at 8.70% per the current Application). LCOC for all 2024 diesel rental costs is $216 to $252 per kW-yr assuming $186.02 average YEC rental cost per kW in year 1 with escalation in range of 3% to 4%/yr, 40 year project life and YEC WACC for new rate base of 6.018%/year per 2024 GRA; with a shorter 20 year rental life, the LCOC for all 2024 rental costs with these same assumptions is $202 to $220 per kW-yr; with infrastructure capital costs and 40-year life, LCOC for all 2024 rental costs is $227 to $264 per kw-yr.

[3] LCOC for rental diesels (average for all units in 2024) with the same WACC as assumed above and a 10 year life applicable to DSM programs is $194/ kW-yr with 3% annual inflation of rental costs and $202/kW-with 4% annual inflation of rental costs. (Higher LCOC is shown for diesel rentals assuming 40 year life compatible with the diesel replacement units project life).

In the longer-term context, YEC will continue to evaluate the relative cost of diesel rentals versus purchase of new thermal capacity taking into account options to sell purchased new diesels when they are no longer required on a long-term basis, e.g., when new dependable capacity is added to the grid as a result of the development of the Tutshi-Moon Pumped Storage Hydro project. However, based on currently available information, there are significant potential risks involved in purchasing versus renting diesels for capacity that is no longer expected to be needed after 10 years of operation:

- As noted above, the LCOC for Faro rented diesels over a 10-year period with 4% annual price inflation equals $239/kW-yr.

- In contrast, using new purchase costs for the 5 MW of Faro units in service in 2024 at $3.66 million/MW, the LCOC for new units sold in the 11th year after commissioning can only compete with the rental option at unrealistically high sales prices. For example, an unrealistic 10-year sales price equal to 75% of original cost (reflecting the remaining three-quarters of the original expected life) yields an LCOC for the purchase option of $278/kW-yr which remains much higher than the LCOC for the rental option in these specific circumstances.

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 34.84% for non-industrial rates and 31.19% for industrial rates. The Rider J increase to each existing Rider J to recover the Application revenue shortfalls is 8.99% for the 2023 test year and 11.21% for the 2024 test year. As noted below, interim refundable rates at the Rider J rate levels for retail and industrial customers are sought effective October 1, 2023 and effective January 1, 2024.

- **Rider J – Yukon Energy October 1, 2023 Interim Revenue Shortfall Rider** – An interim refundable increase to Rider J of 4.80% starting October 1, 2023 and applicable to all YEC and AEY firm retail sales (all AEY recoveries from this rider would flow through to YEC) and industrial rates. Yukon Energy is proposing an October 1, 2023 effective date for the interim rates to reduce the customer bill impacts from final rates. These interim rates will be replaced with final approved rates as described above. Appendix 4.1A provides the proposed interim refundable Rider J as adjusted for this increase.

- **Rider J – Yukon Energy January 1, 2024 Interim Revenue Shortfall Rider** – An interim refundable increase to Rider J of 12.02% starting January 1, 2024 and applicable to all YEC and AEY firm retail sales (all AEY recoveries from this rider would flow through to YEC) and industrial rates. Yukon Energy is proposing a January 1, 2024 effective date for these interim rates to coordinate with the expected Rider F reduction at that time, and to thereby reduce the customer bill impacts. These interim rates will be replaced with final approved rates as described above. Appendix 4.1B provides the proposed interim refundable Rider J as adjusted for this increase.

It is expected the rates arising from the final order in this GRA will not be in place until some time later in 2024, given the current timing estimates. As outlined in Section 4.5, interim refundable rates at the Rider J rate level are sought effective October 1, 2023 and January 1, 2024. In order to reduce customer bill volatility, YEC seeks approval of the 2023/24 GRA final rates and true-up rider effective August 1, 2024 as this will enable coordination of the true-up rider with the removal of the 2021 YEC GRA true-up Rider J1 of 3.01% which is in effect until July 31, 2024.

The Application also addresses adjustments to the Industrial Fixed Charge rate applicable to VGC Group and Hecla Yukon (previously Alexco) with new interim rates effective January 1, 2024 with true-up adjustment effective starting January 1, 2023 (see Section 4.4.2 and Appendix 4.3).

4.2 OVERVIEW

Yukon Energy's revenue earned from rates is collected from charges for firm power and for secondary (interruptible or surplus) sales when applicable. 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 $0.394 million forecast non-rate revenues[1] and secondary sales forecast revenues of $0.358 million for both 2023 and 2024 test years.

The revenue required from firm rates is $80.688 million in 2023 and $89.673 million in 2024 compared to Yukon Energy's forecast revenues from existing firm electrical rates (including the existing Rider J) at $74.021 million in 2023 and $74.353 million in 2024.

[1] Including items such as pole rentals, connection charges, and other facility rentals.

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 $6.667 million rate revenue shortfall in 2023 and a $15.320 million rate revenue shortfall in 2024 compared to revenue requirements set out in Tab 3. These shortfalls form the basis for the proposed rate increases in this Application.

Table 4.1:
Yukon Energy Revenue Required from Rates
($000s)

	2023	2024
Revenue Requirement	$81,440	$90,425
Less: Other Revenues	$394	$394
Less: Secondary Sales	$358	$358
Revenue Required from Firm Rates	$80,688	$89,673
Less: Revenues from Firm Sales at Existing Rates [includes Rider J]	$74,021	$74,353
Additional Firm Rate Revenues Required	$6,667	$15,320

4.3 SECONDARY ENERGY RATE DESIGN

When available, 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 previous secondary sales in Yukon were 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 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.

Based on the existing mechanism, the latest secondary rates are 12.2 cents per kW.h for secondary wholesale and 13.3 cents per kW.h for secondary retail.[3] The existing 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 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 Minto 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.[4] This requirement was included in the PPA as amended May 14, 2007, which was approved by Board Order 2007-6. To date, the Yukon Utilities Board prerequisites for Rate Schedule 35 have not been met. Accordingly, this rate schedule was never implemented. As Minto mine ceased its mining operations, as discussed in Tab 2, this rate schedule is no longer required.

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[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.
[3] The rates are effective April 1, 2023 as filed with YUB on February 27, 2023. Available at https://yukonutilitiesboard.yk.ca/pdf/Reports/Secondary_Sales_Rate_-_April_1__2023.pdf.
[4] See Board Order 2007-5.

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 Victoria Gold (VGC Group) and Hecla Yukon (previously Alexco) mines for both 2023 and 2024. No other major industrial customers are forecast to require service under Rate Schedule 39 in the test years.

Adjustments to the Fixed Charge applicable to VGC Group and Hecla Yukon need to be considered effective January 1, 2023 and January 1, 2024 is part of this Application as reviewed in Section 4.4.2 below and Appendix 4.3.

4.4.1 Rider J Applicable to Industrial Customers

Rates for major industrial customers have been set in recent GRAs pursuant to Section 6 of OIC 1995/90, as amended by subsequent OICs (see Tab 10 for copies of OICs).

Section 6.1 of OIC 1995/90 requires the Board to ensure that rates charged to major industrial customers are sufficient to recover the cost of service to that customer class (with those costs treating all of Yukon as a single rate zone and the same rates being charged by both utilities). However, rate policy OICs since 2012 (namely, OICs 2012/68, 2014/23 and 2018/220) have required 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.[5] Section 2.1 of OICs 2012/68 and 2014/23 included provisions that outlined when this requirement would expire. OIC 2018/220 has repealed the prior expiry provisions, i.e., the provisions of Section 2.1 as currently applied require rate adjustments to apply equally, when measured as percentages, to all classes of retail and major industrial customers and this provision now does not have an expiration date.[6]

The existing Rider J rate applicable for major industrial customer rates (Rate Schedule 39) is 31.19%. In conformance with OIC 2018/220 and the Rider J increases reviewed in Table 4.2, the existing Rider J applicable to Rate Schedule 39 is to be increased by 8.99% for 2023 and 11.21% for 2024

[5] OIC 2008/149 included this direction for all classes of retail customers. OIC 2007/94 also added subsection 6(3) to OIC 1995/90 directing that the Board ensure that rates charged to major industrial customers conform the Rate Schedule 39 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. This OIC 2007/94 requirement (as well as the attached Schedule A) was deleted in OIC 2018/220.
[6] OIC 2018/220 replaced subsection 6(3) with the following: "Despite subsection (1), the Board must ensure that the rates charged to major industrial customers conform to Section 2.1."

(applicable total Rider J rate for major industrial customers rates of 40.18% for 2023 and 51.39% for 2024). The interim refundable Rider J increase of 4.80% effective October 1, 2023 would apply to Rate Schedule 39.

4.4.2 VGC Group and Hecla Yukon (previously Alexco) Fixed Charge

Pursuant to Rate Schedule 39, a Fixed Charge is assigned to industrial customers that use the Mayo-Keno transmission facilities;[7] the Fixed Charge assigns to these customers an 85% share of annual depreciation and return cost related to these transmission facilities. The basis and premise for the Fixed Charge was initially reviewed as part of the Alexco Resource Corp Power Purchase Agreement (PPA) approved in 2011 by Order 2011-01, and confirmed in the VGC Group PPA[8] approved in 2018 by Board Order 2018-04.

Rate Schedule 39 as currently approved includes a Fixed Charge for VGC Group of $53,674.48/month and for Hecla Yukon of $12,183.16/month.[9] The Fixed Charges are adjusted at year-end as per provision of the Rate Schedule 39.[10]

YEC in its Limited Scope Application dated April 8, 2022, noted that some remaining work was expected during 2022 and costs for any future work required for the relevant facilities would be addressed as required after the work was concluded. The fixed charge adjustment calculations for 2023 and 2024 include a net spending of $0.030 million in 2022 on the McQuesten transmission line and a net spending of $0.215 million in 2022 on the SVC/Statcom.[11]

In summary, as reviewed in Appendix 4.3, there is a calculated Fixed Charge of $69,307.69 per month effective January 1, 2023 and a calculated Fixed Charge of $67,850.58 per month effective January 1, 2024, with allocation between VCG Group and Hecla Yukon based on forecast loads for 2023 and 2024 as shown in Table 4.3-2 of Appendix 4.3 [$46,554.84/month for VGC Group and $21,295.74/month for Hecla Yukon].

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[7] This was established in the 2010 Alexco PPA to ensure that Alexco mine paid its share of costs for transmission facilities maintained in service to serve future industrial customers after the closure of the UKHM mine.
[8] The Power Purchase Agreement (PPA) dated November 9, 2017 between YEC, Victoria Gold Corp., and StrataGold Corporation (Victoria Gold Corp. and StrataGold Corporation are collectively, the VCG Group) for transmission connection to the mine site.
[9] Approved as interim as per YUB Order 2022-04 and as final as per YUB Order 2022-07.
[10] Within 60 days of calendar year end, YEC will adjust the allocation based on each mine's actual share of the Major Industrial Customer MWh load on the Transmission Facilities.
[11] Transmission line cost of $0.126 million offset by contributions of $0.096 million to the net cost of $0.030 million; Statcom cost of $0.772 million offset by contributions of $0.557 million to the net cost of $0.215 million.

In order to avoid multiple rate changes, Yukon Energy is proposing an interim Fixed Charge for VGC Group of $46,554.84/month and for Hecla Yukon of $21,295.74/month effective January 1, 2024. These interim rates will be replaced with final approved Fixed Charges in the Compliance Filing. The variance between the existing rates and final rates for the period from January 1, 2023 and December 31, 2023, and the variance between interim and final rates from January 1, 2024 onward will be recovered from/refunded to these two specific customers by a process to be approved with the final rates.

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 AEY 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.

Section 2.1 provided in OIC 2008/149 was replaced in April 2012 with OIC 2012/68. This 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 subsequently extended this OIC direction to December 31, 2018. OIC 2018/220 removed subsection 2.1(3) which established an expiry date for Section 2.1. With this change, the provisions of Section 2.1(1) currently remain in effect without any expiry date.

In accordance with OIC 2018/220, the Application proposes that the Yukon Energy revenue shortfall for 2023 and 2024 as shown in Table 4.1 be recovered through increases to Revenue Shortfall Riders applied across the board to all firm retail and industrial rates of YEC and AEY. Ignoring timing for actual rate implementation (i.e., the proposed Interim Revenue Shortfall Riders and subsequent final rate riders when the proceeding is concluded), the proposed Revenue Shortfall Riders are as follows (see Section 4.4 of this Application for details regarding how these riders also apply to industrial rates):

- An across the board increase is required on an ongoing basis as provided in Table 4.2, 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 J1, Rider F and Rider E):
  - Of 6.25% for 2023;
  - A further increase of 7.40% for 2024 [compounded increase of 14.11%].
- Considering that the current YEC Rider J is applied only to base rates, the required new Rider J increase from the current 34.84% for non-industrial and 31.19% for industrial class:
  - To 43.83% for non-industrial and 40.18% for industrial class to recover the 2023 test year shortfall;
  - To 55.04% for non-industrial and 51.39% for industrial class to recover the 2024 test year shortfall;

The calculations of Rider J are provided in Table 4.2.

Table 4.2:
Calculation of Required 2023 and 2024 Rate Increases and Rider J

Line #			Forecast 2023	Forecast 2024
1a	Consolidated Firm Retail Sales Revenues - Base Rates[1]	$000	64,471	67,298
1b	Consolidated Firm Industrial Sales Revenues - Base Rates	$000	9,718	8,771
2a	Consolidated Rider J Revenues[2]	$000	26,265	26,183
2b	AEY Rider R Revenues[3]	$000	6,158	6,314
3=1+2	**Total Consolidated Firm Sales Revenues at existing rates**	$000	106,611	108,566
4=Table 4.1	Retail Revenue increase required in 2023	$000	6,667	
5a=4/3	Required Rate Increase on total Consolidated Revenues	%	6.25%	
5b=4/(1a+1b)	Rider J Increase Required	%	8.99%	
6=3 * 5a	**Total Consolidated Firm Sales Revenues with 2023 Increase**	$000	113,278	115,355
7=Table 4.1	Retail Revenue increase required in 2024	$000		15,320
8=6-3	To Be Recovered from 2023 Increase	$000		6,789
9=7-8	Net Retail Revenue increase required in 2024	$000		8,531
10a=9/6	Required Rate Increase on total Consolidated Revenues	%		7.40%
10b=9/(1a+1b)	Rider J Increase Required	%		11.21%
11=6 * 10a	**Total Consolidated Firm Sales Revenues with 2024 Increase**	$000		123,886
12=5a*(1+10a)+10a	Total Cumulative 2023 and 2024 Rate Increases (compounded)			14.11%
	Rider J Required			
13=5b and 10b	Rider J Increase Required	%	8.99%	11.21%
14	Existing Rider J - non-industrial	%	34.84%	43.83%
15	Existing Rider J - industrial	%	31.19%	40.18%
16=13+14	Total Rider J with increases - non-industrial	%	43.83%	55.04%
17=13+15	Total Rider J with increases - industrial	%	40.18%	51.39%

Notes:
1. Total Consolidated Retail Revenues at existing Base Rates include revenues from YEC and AEY's residential, general service and streetlight sales.
2. Consolidated Rider J revenues at existing rates include YEC's Rider J at 34.84% for firm YEC and AEY retail sales and at 31.19% for firm industrial sales based on YUB Order 2023-05.
3. AEY Rider R Revenues at existing rates include AEY's Rider R at 8.30% for firm retail and industrial base rate sales of YEC and AEY.

In order to implement rate changes, YEC is proposing the following interim rates:

- Rider J of 39.64% for all firm non-industrial, and 35.99% for all firm industrial, be applied initially as of October 1, 2023 as an interim refundable rate rider, equal to a 4.80 percentage point increase in the existing Rider J rates for non-industrial and industrial rates [reflects about half of the required 2023 Rider J increase and about one quarter of the total Rider J rate increase for 2023 and 2024 in the current GRA].

- In order to reduce customer bill volatility, Yukon Energy is proposing the second interim rates effective January 1, 2024, as this will enable coordination of these final rates with the expected reduction in Rider F rate. Rider J of 51.66% for all firm non-industrial, and 48.01% for all firm industrial, be applied as of January 1, 2024 as an interim refundable rate rider which is equal to a 12.02% increase over the October 1, 2023 interim Rider J [reflects about 80% of the required total Rider J rate increase for 2023/24 GRA].

These interim refundable rate rider proposals recognize that rates arising from the final order in this GRA will not be in place until sometime mid or late 2024 given current timing estimates, and that any required "true-up" for 2023 and 2024 will be part of the YUB's final order setting rates arising from this Application. Yukon Energy seeks approval of the 2023/24 GRA final rates and true-up rider effective August 1, 2024 as this will enable coordination of the true-up rider with the removal of the 2021 YEC GRA true-up Rider J1 of 3.01% which is in effect until July 31, 2024. The proposed interim rates reduce impacts from the final rate increase and required true-up.

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. Appendix 4.2 bill impacts assume existing AEY rates without any of the changes in the current AEY GRA.

Table 4.3 summarizes Appendix 4.2 residential and commercial non-government bill impacts with the rate changes proposed in the Application, assuming that Rider F approximates zero effective January 1, 2024 and that the true-up Rider J1 is adjusted at August 1, 2024 from 3.01% to an estimated 4.61%.[12] In addition to the customer use levels assumed in Appendix 4.2 (1,000 kW.h/month for residential and 2,000 kW.h/month for commercial), Table 4.3 presents estimated bill impacts for average annual Yukon customer use assumed at 850 kW.h/month for residential and 3,500 kW.h per month with 15 kW demand for commercial.

In summary, estimated bill changes in Table 4.3 as of August 2024 due to the Application are equal to about 6% of July 2023 bills for each case examined. By way of example, the bill change for a residential customer using 1,000 kWh/month would see an increase of 6.2% over July 2023. The bill impacts vary by

[12] The 2021 GRA true-up rider (Rider J1) of 3.01% expires on July 31, 2024. The 2023/24 GRA true-up rider (Rider J1) that would be applied starting September 1, 2024 is estimated at 4.61% assuming a 24-month period for implementation. The 2023/24 GRA true up rider will be determined in the YEC Compliance Filing after the Board's decision on the Application.

customer class and consumption levels. Final bill estimates will be impacted by expected AEY's 2023/24 GRA.

Table 4.3:
Application Bill Impacts for Residential & Commercial Non-Government Customers

	Pre-2023/24 GRA	2023/24 GRA		
	July 2023	October 1, 2023 Interim	January 1, 2024 Second Interim	August 1, 2024 Final/True-up
	A	B	C	D
Monthly Bills				
Residential Non-Government, Whitehorse [$/month]				
850 kWh/month consumption	**$186.12**	**$191.78**	**$192.04**	**$197.85**
change from July 2023, $/month		*$5.65*	*$5.92*	*$11.72*
change from July 2023, %		3.0%	3.2%	6.3%
Incremental change, %		3.0%	0.1%	3.0%
1,000 kWh/month consumption	**$215.19**	**$221.72**	**$221.72**	**$228.42**
change from July 2023, $/month		*$6.53*	*$6.53*	*$13.23*
change from July 2023, %		3.0%	3.0%	6.1%
Incremental change, %		3.0%	0.0%	3.0%
Commercial Non-Government, Whitehorse [$/month]				
2,000 kWh/month consumption [5 kW demand]	**$379.00**	**$390.37**	**$386.15**	**$397.82**
change from July 2023, $/month		*$11.37*	*$7.15*	*$18.82*
change from July 2023, %		3.0%	1.9%	5.0%
Incremental change, %		3.0%	-1.1%	3.0%
3,500 kWh/month consumption [15 kW demand]	**$793.89**	**$818.08**	**$821.43**	**$846.27**
change from July 2023, $/month		*$24.19*	*$27.54*	*$52.37*
change from July 2023, %		3.0%	3.5%	6.6%
Incremental change, %		3.0%	0.4%	3.0%

Note: See Appendix 4.2 for detailed calculations for 1,000 kWh/ month residential and 2,000 kWh/month commercial bill calculations; the same assumptions were used for 850 kWh/ month residential and 3,500 kWh commercial bill impacts. January 1, 2024 bills assume Rider F is set at zero. The bill calculations exclude the impacts of AEY 2023/24 GRA.

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.

Following a two-part application regarding ERA matters filed by YEC in 2017, YUB Order 2018-05 approved the amended Rate Schedule 42 attached as Appendix B to the Order.

Rate Schedule 42 includes a fixed Energy Charge of 8.298 cents per kW.h was approved effective June 1, 2011 as per YUB Order 2011-05 following a joint Phase II application. No change in the Energy Charge or the existing ERA is proposed as a result of this Application.

APPENDIX 4.1A
RIDER J

Effective: 2023/10/01
Supersedes: 2023/03/01

RIDER J

NEW INTERIM RIDER J TO INCLUDE RECOVERY OF PORTION OF 2023/24 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 39.64% applicable to the base rates of the following rate classes to recover of a portion of the 2023/24 revenue shortfall. All ATCO Electric Yukon 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 35.99% applicable all firm sales revenues, including fixed charge and 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 4.1B
RIDER J

Effective: 2024/01/01
Supersedes: 2023/10/01

RIDER J

NEW INTERIM RIDER J TO INCLUDE RECOVERY OF PORTION OF 2023/24 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 51.66% applicable to the base rates of the following rate classes to recover of a portion of the 2023/24 revenue shortfall. All ATCO Electric Yukon 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 48.01% applicable all firm sales revenues, including fixed charge and 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

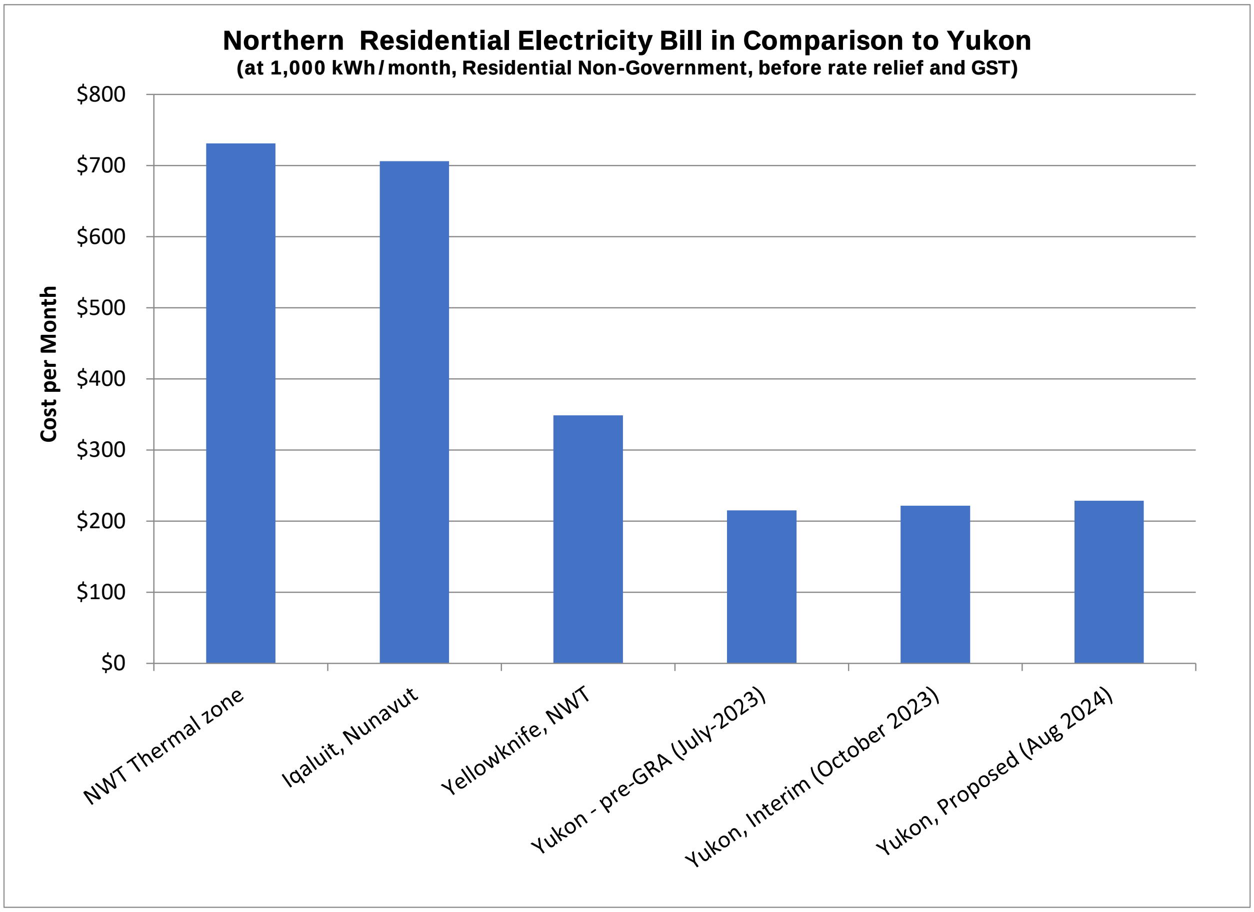
Table 4.2A-1:
Residential Electricity Bills in Comparison to Yukon
(1000 kWh/month consumption, Residential Non-Government, $)

		Monthly Bills before rate relief and taxes
1	NWT Thermal zone	$731.40
2	Iqaluit, Nunavut	$706.50
3	Yellowknife, NWT	$348.69
4	Yukon - pre-GRA (July-2023)	$215.19
5	Yukon, Interim (October 2023)	$221.72
6	Yukon, Proposed (Aug 2024)	$228.42
7	Calgary, AB	$199.38
8	Edmonton, AB	$194.78
9	Charlottetown, PEI	$177.77
10	Halifax, NS	$172.98
11	Regina, SK	$165.07
12	Toronto, ON	$158.85
13	Ottawa, ON	$145.89
14	Moncton, NB	$139.35
15	St. John's, NL	$137.58
16	Vancouver, BC	$113.92
17	Winnipeg, MB	$102.44
18	Montreal, QB	$75.86

Notes:

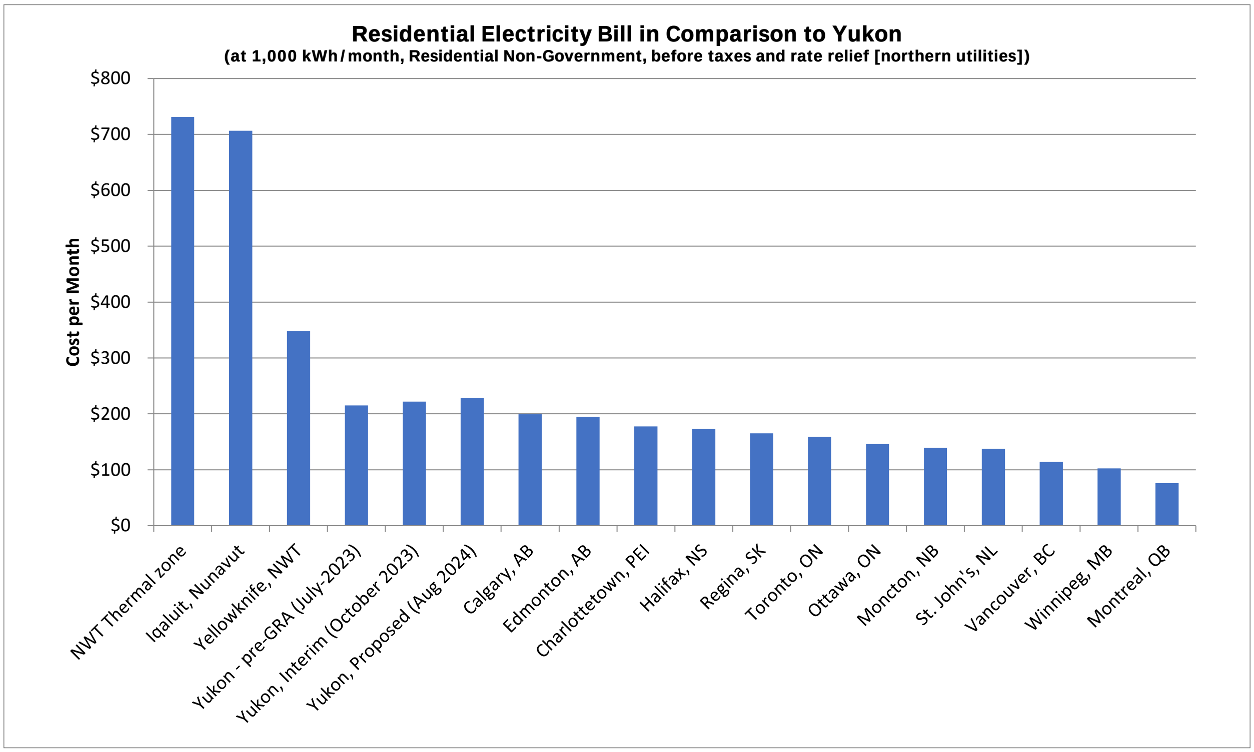
1. Monthly Bills are before taxes and rate relief [Hydro Quebec does not specify if the rate comparison includes rate relief].
2. Yukon existing bills include YEC Rider J [34.84%] and Rider J1 [3.01%], AEY Rider R [8.30%] and Rider F.
3. Yukon proposed bills assume interim Rider J increase of 4.83% effective October 1, 2023, second interim effective January 1, 2024 equal to Rider F reduction and final rates effective August 1, 2024. The bill calculations do not include the impact of AEY 2023/24 GRA.
4. The monthly bills for Yellowknife are calculated using the rates in place as of July 31, 2023. Available at https://www.northlandutilities.com/en-ca/customer-billing-rates/bill-calculator/northland-utilities-limited-yellowknife.html [accessed on July 31, 2023].
5. The monthly bills for NWT Thermal Zone are calculated using the rates in place effective April 1, 2023. Available at https://www.ntpc.com/customer-service/residential-service/what-is-my-power-rate [accessed on July 31, 2023].
6. The monthly bills for Iqaluit are calculated using the territorial rates approved effective October 1, 2022, but also include fuel rider effective April 1, 2023. Available at https://www.qec.nu.ca/customer-care/accounts-and-billing/customer-rates [accessed on July 31, 2023].
7. Bills for Toronto and Ottawa are based on Ontario Energy Board Bill Calculator. Available at https://www.oeb.ca/rates-and-your-bill/bill-calculator [accessed on July 31, 2023].
8. The monthly bills for the other cities are from Hydro Quebec's Comparison of Electricity Prices in Major North American Cities, Rates in effect April 1, 2022. Available at https://www.hydroquebec.com/data/documents-donnees/pdf/comparison-electricity-prices.pdf [accessed on July 31, 2023].

Figure 4.2A-1:[1]
Northern Residential Electricity Bill in Comparison to Yukon



[1] Please see notes to Table 4.2A-1.

Figure 4.2A-2:[2]
Residential Electricity Bill in Comparison to Yukon



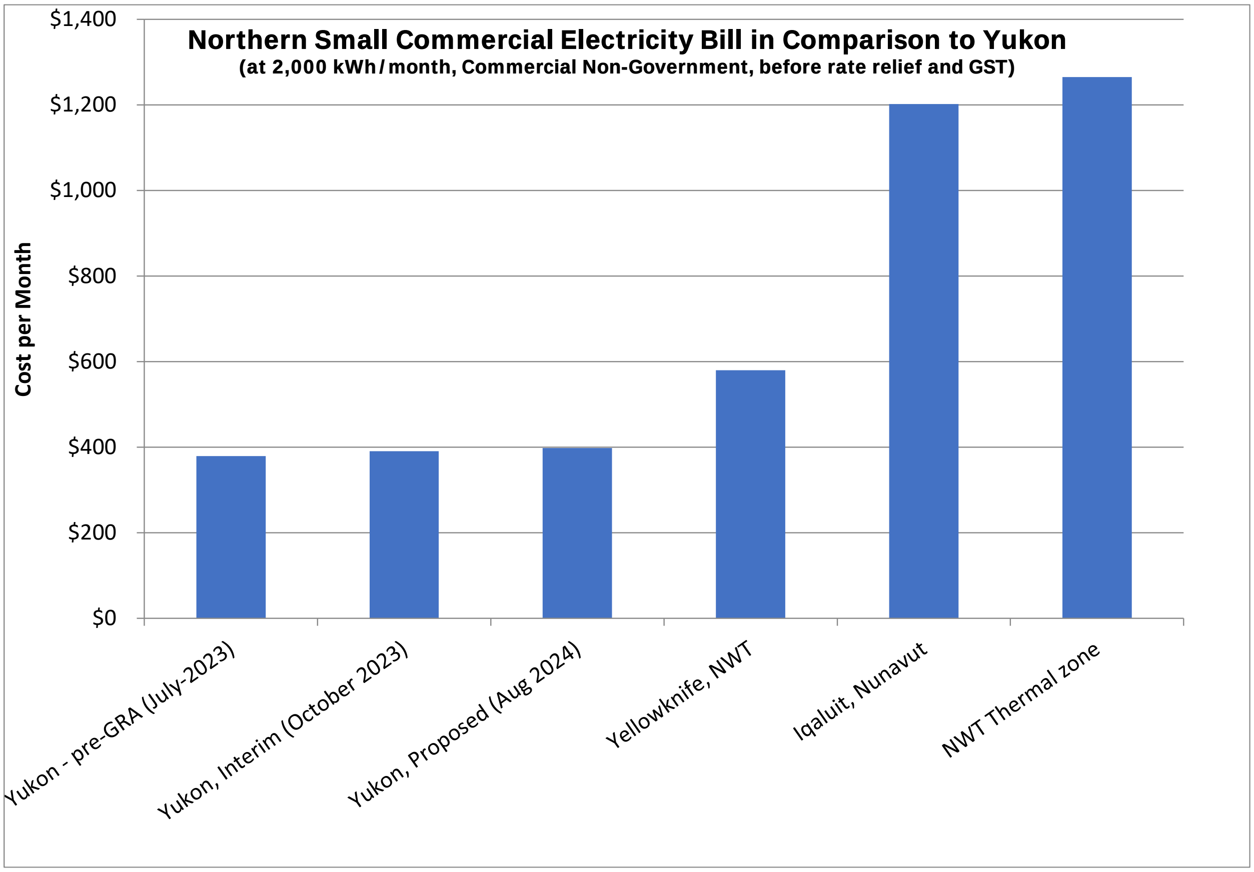
[2] Please see notes to Table 4.2A-1.

Table 4.2A-2: [3]
Small Commercial Electricity Bills in Comparison to Yukon
(2000 kWh/month consumption, Commercial Non-Government, $)

		Monthly Bills before rate relief and taxes
1	Yukon - pre-GRA (July-2023)	$379.00
2	Yukon, Interim (October 2023)	$390.37
3	Yukon, Proposed (Aug 2024)	$397.82
4	Yellowknife, NWT	$579.32
5	Iqaluit, Nunavut	$1,201.40
6	NWT Thermal zone	$1,264.60

[3] Please see notes to Table 4.2A-1.

Figure 4.2A-3[4]
Northern Small Commercial Electricity Bill in Comparison to Yukon



[4] Please see notes to Table 4.2A-1.

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	Existing [July 2023]		2023/24 GRA Interim [October 1, 2023]		2023/24 GRA Second Interim [Jan 1, 2024] and Rider F removal		2023/24 GRA Final and True-up; 2021 GRA true-up expires [July 31, 2024]	
			Rates	Bill [$/month]	Rates	Bill [$/month]	Rates	Bill [$/month]	Rates	Bill [$/month]
	Base Rates									
1	Customer Charge (per month)		$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
3=KWh*Base rate	Second Block Energy (kWh)	-								
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.01635	$16.35	$0.01635	$16.35		$0.00		$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		34.84%	$47.40	39.64%	$53.93	51.66%	$70.28	54.98%	$74.80
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)		3.01%	$4.10	3.01%	$4.10	3.01%	$4.10	4.61%	$6.28
7=(1+2+3)*Rider R rate	AEY Rider R (%)		8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29
8=Sum(1:7)	Total Before Tax Rebate, IER, GST			$215.19		$221.72		$221.72		$228.42

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:	Existing [July 2023]		2023/24 GRA Interim [October 1, 2023]		2023/24 GRA Second Interim [Jan 1, 2024] and Rider F removal		2023/24 GRA Final and True-up; 2021 GRA true-up expires [July 31, 2024]	
	2,000 kWh								
	5 kW								
		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
2=KWh*Base rate	First Block Energy (kWh)	$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)	$0.01635	$32.70	$0.01635	$32.70	$0.00000	$0.00	$0.00000	$0.00
4=(1+2)*Rider J rate	YEC Rider J (%)	34.84%	$82.55	39.64%	$93.92	51.66%	$122.40	54.98%	$130.27
5=(1+2)*Rider J1 rate	YEC Rider J1 (%)	3.01%	$7.13	3.01%	$7.13	3.01%	$7.13	4.61%	$10.93
6=(1+2)*Rider R rate	AEY Rider R (%)	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67
7=Sum(1:6)	Total Before Tax Rebate, GST		$379.00		$390.37		$386.15		$397.82

APPENDIX 4.3
VGC GROUP AND HECLA YUKON (PREVIOUSLY ALEXCO) FIXED CHARGE ADJUSTMENTS

APPENDIX 4.3: VGC GROUP AND HECLA YUKON (PREVIOUSLY ALEXCO) FIXED CHARGE ADJUSTMENTS

Background

Pursuant to Rate Schedule 39, a Fixed Charge is assigned to industrial customers that use the Mayo-Keno transmission facilities; the Fixed Charge assigns to these customers an 85% share of annual depreciation and return cost related to these transmission facilities. The basis and premise for the Fixed Charge was initially reviewed as part of the Hecla Yukon (previously Alexco) Power Purchase Agreement (PPA) approved in 2011, and confirmed in the VGC Group PPA[1] approved in 2018 by Board Order 2018-04.

Rate Schedule 39 as currently approved by the Yukon Utilities Board ("YUB" or "Board") includes a Fixed Charge for VGC Group of $53,674.48/month and for Hecla Yukon of $12,183.16/month.[2] The Fixed Charges are adjusted at year-end as per provision of the Rate Schedule 39.[3]

Section 7.7 (b) of the VGC Group PPA notes that after the Transmission Facilities Development Operation Date,[4] YEC will apply to the YUB to amend the Transmission Facilities Fixed Charge based on YEC's adjusted annual costs for depreciation and return on rate base related to the Transmission Facilities plus the SVC/Statcom and YEC's McQuesten Substation Costs.

YEC in its Limited Scope Application dated April 8, 2022, noted that some remaining work was expected during 2022 and costs for any future work required for the relevant facilities would be addressed as required after the work was concluded. The fixed charge adjustment calculations for 2023 and 2024 include a net spending of $0.030 million in 2022 on the McQuesten transmission line and a net spending of $0.215 million in 2022 on the SVC/Statcom.[5]

[1] The Power Purchase Agreement (PPA) dated November 9, 2017 between YEC, Victoria Gold Corp., and StrataGold Corporation (Victoria Gold Corp. and StrataGold Corporation are collectively, the VCG Group) for transmission connection to the mine site.
[2] Approved as interim as per YUB Order 2022-04 and as final as per YUB Order 2022-07.
[3] Within 60 days of calendar year end, YEC will adjust the allocation based on each mine's actual share of the Major Industrial Customer MWh load on the Transmission Facilities.
[4] Defined as the date provided by YEC to VGC Group to confirm that the Transmission Facilities Development has been completed and is in service to deliver Grid Electricity to the Mine Facilities through the Mine Facilities Spur. The Transmission Facilities Development is defined as any future transmission facilities developed by YEC to replace existing Transmission Facilities and to connect the McQuesten Substation with a substation at either Mayo or Stewart Crossing.
[5] Transmission line cost of $0.126 million offset by contributions of $0.096 million to the net cost of $0.030 million; Statcom cost of $0.772 million offset by contributions of $0.557 million to the net cost of $0.215 million.

Table 4.3-1 provides YEC forecast year-end Transmission Facilities Fixed Costs in rate base (net costs after contributions and amortization) for 2023 and 2024. Table 4.3-1 breaks out these year end rate base costs and annual amortization costs as follows:

- **Existing Transmission Costs** (these costs are reflected in the current Fixed Cost Charge, with amortization as previously reported);

- **YEC's McQuesten Substation Costs** (these are costs that VCG Group recovered from YEC, related to YEC upgrades to accommodate 138 kV transmission if developed in the future; this work was completed in 2019, and costs are amortized over 54 years as previously reported);

- **Transmission Facilities Development Costs and SVC/Statcom Costs**;

  - YEC net costs after federal government contributions for the new transmission between Mayo and McQuesten Substation [Transmission Facilities Development Costs] that is put in service in March 2021 - costs for these facilities are amortized over 60-65 years as previously reported; and

  - YEC net costs after federal government contributions for the SVC/Statcom at Stewart Crossing that is put in service in October 2021 - costs for these facilities are amortized over 10 years consistent with the direction provided by YUB in Order 2022-03 [please refer to Order 2022-03 Compliance Filing filed on April 14, 2022, page 2-13].

As summarized in Table 4.3-2, a calculated Fixed Charge of $69,307.69 per month effective January 1, 2023 and a calculated Fixed Charge of $67,850.58 per month effective January 1, 2024, with allocation between VCG Group and Hecla Yukon based on forecast loads for 2023 and 2024 as shown in Table 4.3-2.

Transmission Facilities Fixed Costs for 2023 and 2024 are calculated based on 2023/24 GRA proposed weighted cost of capital and will be adjusted as required in the 2023/24 GRA Compliance Filing based on the final approved weighted cost of capital.

Table 4.3-1:
YEC Year-End Transmission Facilities Fixed Costs

		2023	2024
	Existing Transmission net costs		
1	Year End Net Cost	1,155,849	1,155,849
2	Annual Depreciation	18,069	18,069
3	Accumulated Depreciation	324,779	342,848
4=1-3	Year End Net Book Value	831,070	813,001
5	Mid-Year Rate Base	**840,105**	**822,036**
	Total New Transmission Facilities Fixed Costs		
	YEC's McQuesten Substation Costs*		
6	Year End Net Cost [net of contributions]	930,563	930,563
7	Annual Depreciation	17,233	17,233
8	Accumulated Depreciation	80,120	97,353
9=6-8	Year End Net Book Value	850,443	833,210
10	Mid-Year Rate Base	**859,059**	**841,827**
	Transmission Facilities Development**		
11	Year End Cost	15,844,817	15,844,817
12	Year End Contributions	-11,537,390	-11,537,390
13=11+12	Year End Net Cost	4,307,427	4,307,427
14	Annual Depreciation	67,185	67,185
15	Accumulated Depreciation	187,322	254,507
16=13-15	Year End Net Book Value	4,120,105	4,052,920
17	*Rate Base*	**4,153,697**	**4,086,513**
	SVC/Statcom Costs***		
18	Year End Cost	13,991,451	13,991,451
19	Year End Contributions	-10,179,565	-10,179,565
20=18+19	Year End Net Cost	3,811,887	3,811,887
21	Annual Depreciation	381,189	381,189
22	Accumulated Depreciation	804,958	1,186,147
23=20-22	Year End Net Book Value	3,006,929	2,625,740
24	Mid-Year Rate Base	**3,197,523**	**2,816,334**
	Total New Transmission Facilities Fixed Costs		
25=10+17+24	**Rate Base**	**8,210,280**	**7,744,674**
26=7+14+21	**Depreciation**	**465,606**	**465,606**

Notes:

* VGC Group PPA Section 7.7 (b) notes Fixed Charge will include YEC's McQuesten Substation Costs. As per section 6 (d) YEC's McQuesten Substation Costs are after VGC Group contributions.

** The completion date for Transmission Facilities is March 15, 2021 [also includes the net spending of $0.030 million in 2022].

*** The completion date for SVC/Statcom is October 28, 2021 [also includes the net spending of $0.215 million in 2022]. The depreciation is based on a 10-year life [please refer to Order 2022-03 Compliance Filing filed on April 14, 2022, page 2-13].

Table 4.3-2:
Adjusted YEC Annual Transmission Facilities Fixed Charge Calculation

	2023	2024	
Existing Transmission Facilities			
Rate Base	$840,105	$822,036	Table 1, Line 5
Average Cost of Capital (2023/24 GRA)	5.47%	5.54%	
Return on Rate Base	$45,929	$45,504	
Depreciation	$18,069	$18,069	Table 1, Line 2
Subtotal existing facilities	**$63,998**	**$63,574**	
New Transmission Facilities [net of contributions]			
Rate Base	$8,210,280	$7,744,674	Table 1, Line 25
Average Cost of Capital (2023/24 GRA)	5.47%	5.54%	
Return on Rate Base	**$448,857**	**$428,711**	
Depreciation	$465,606	$465,606	Table 1, Line 26
Subtotal new facilities	**$914,463**	**$894,317**	
Total Transmission Facilities Fixed Cost	**$978,461**	**$957,891**	
Fixed Charge at 85% of annual costs	$831,692	$814,207	
Fixed Charge per month	$69,307.7	$67,850.6	
Major Industrial Use of Transmission Facilities	Sales, MW.h	Sales, MW.h	
Victoria Gold	43,583	47,596	
Hecla Yukon (Alexco)	15,074	21,772	
Monthly Fixed Charges, $/month	**Jan-01-2023**	**Jan-01-2024**	
Victoria Gold	$51,496.85	$46,554.84	
Hecla Yukon (Alexco)	$17,810.84	$21,295.74	
Total	$69,307.69	$67,850.58	

Notes:

1. 2023/24 GRA proposed weighted cost of capital and will be adjusted as required in the 2023/24 GRA Compliance Filing based on the final approved weighted cost of capital.
2. Forecast Victoria Gold and Hecla Yukon (previously Alexco) MWh loads as per YEC's 2023/24 GRA forecast.

TAB 5
CAPITAL PROJECTS

5.0 CAPITAL PROJECTS

Capital project investments in rate base are generally grouped in one of three categories: capital works on property, plant and equipment; deferred cost studies (including new supply and other feasibility studies, studies required by regulation or relicensing and dam safety works); and intangible assets. This section provides an overview of Yukon Energy's actual capital spending since the 2021 General Rate Application, as well as forecast capital spending for 2023 and 2024.

- **Overview of Capital Spending:** Provides a summary of Yukon Energy capital spending from 2021 through 2024.

- **Capital Works:** Reviews capital spending on property, plant and equipment (PP&E). This includes a detailed discussion of the major projects over $1 million that are completed, in service and included in rate base in the test years (see Section 5.2.1 and Appendix 5.1A). Descriptions for projects in excess of $100,000 and up to $1 million that are forecast to be completed and included in rate base by 2024 are provided in Section 5.2.2 and Appendix 5.1B.

- **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 2021 to 2024. Descriptions of deferred cost projects greater than $1 million that are completed and included in rate base are provided in Section 5.3.1 and Appendix 5.2A. Descriptions of studies between $100,000 and up to $1 million that have been completed and are to be included in rate base by 2024 are provided in Section 5.3.2 and Appendix 5.2B.

- **Spending on Intangible Assets:** Intangible asset cost projects from 2021 to 2024 that are forecast to be completed and in rate base by 2024 that are greater than $1 million are provided in Section 5.4.1 and Appendix 5.3A, and that are between $100,000 and up to $1 million are provided in Section 5.4.2 and Appendix 5.3B.

Tables 5.1 to 5.7 at the end of Tab 5 provide details of capital, deferred and intangible assets projects constructed since 2021 and forecasts for the 2023 and 2024 test years, including projects that have all of their costs remain as work in progress (WIP) at the end of 2024 (see Table 5.7).

5.1 OVERVIEW OF CAPITAL SPENDING

Tab 1 outlines contextual factors driving the requirement for significant and timely capital investments in all aspects of the Yukon Integrated System, including generation, transmission, distribution, storage and grid stability, and end-use. This includes (i) steady growth in electricity demand, (ii) the need to upgrade or replace aging generation, transmission and distribution infrastructure, (iii) transition from reliance on fossil fuels in Yukon's heating and transportation sectors to clear energy alternatives, and (iv) the impact of rising costs and project complexity.

With this context, Yukon Energy's capital spending from 2021 through 2024 reflects 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.

- **Focus on Sustaining Capital Requirements:** Since the 2021 GRA spending has focused 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 and intangible assets.

- **Investment to Address Capacity Planning Requirements:** The 2021 GRA identified the continuing need for investments to address dependable capacity planning requirements.

- **Investment for New Supply Options or to Maximize Renewable Energy Generation from existing facilities:** The 2021 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 [Southern Lakes]).

Total spending on PP&E projects since 2021 (i.e., during 2022, 2023 and 2024) as shown in Table 5.1 totals $189.993 million, with 83% of this spending in major projects over $1 million ($157.994 million); total PP&E cost transfers forecast to rate base in these same years (before contributions, and including transfers for costs spent before 2022) totals $92.385 million. Contributions transferred to rate base to offset some of these expenditures since the end of 2021 approximate $8 million (Table 5.1).

Deferred cost capital spending (excluding WIP and amortization expenses, and after contributions) added to 2024 rate base since 2021 as shown in Table 5.6 totals $19.916 million, with 80% of this rate base addition in major projects over $1 million ($16.026 million), Deferred cost spending since 2021 retained in 2024 WIP (after contributions) as shown in Table 5.7 totals $27.7 million, with 96% of this spending in major projects over $1 million ($26.9 million).

Actual and forecast intangible assets spending (excluding WIP) added to 2024 rate base (beyond what was approved in the 2021 GRA) as shown in Table 5.6 totals approximately $11.1 million, with 90% of this rate base addition in major projects over $1 million ($10.0 million). Intangible assets spending since 2021 retained in 2024 WIP (after contributions) as shown in Table 5.7 totals $4.6 million, with 94% of this spending in major projects over $1 million ($4.3 million).

5.2 CAPITAL WORKS

This section reviews (a) major capital works projects (projects with total cost over $1.0 million) undertaken by YEC since the 2021 GRA hearing and planned for 2022 and 2024; and (b) ongoing capital projects costing between $100,000 and $1 million forecast.

5.2.1 Major Projects > $1 Million – Rate Base Additions

Test year spending on major capital works projects focuses 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 on new supply options and expenditures to ensure sufficient dependable capacity for the integrated grid.

Total forecast to be added to year-end net rate base, net of contributions but before depreciation impacts, for major capital works projects by the end of 2024 is approximately $71.953 million, including rate base adjustments to projects reviewed and approved in the 2021 GRA. Each major project added to rate base is reviewed separately below (see also Tables 5.1 and 5.6 at the end of Tab 5):

- **Spending to address Capacity Planning Requirements** – Net rate base impact of approximately $33.825 million:
    - **Thermal Replacement (16.5 MW)** – Forecast cost of approximately $18.176 million for 5 MW diesel replacement forecast to be completed and in service at Faro in 2024, and cost of $0.15 million in 2021 for completed Whitehorse feasibility study.
    - **2023 Mayo-Faro Diesel Infrastructure** – Forecast cost of $4.300 million in 2023; and forecast to be completed and in service in 2023.

  - **Whitehorse Interconnection** – Forecast cost of approximately $11.199 million; and forecast to be completed and in service in 2024.

- **Spending on Sustaining Capital -** Net rate base impact of approximately $30.262 million:

  - **Transmission Line Replacement L178** – Actual cost of approximately $5.084 million for facilities in service to the end of 2022, with forecast cost of $1.000 million in 2023 and $5.000 million in 2024 for facilities forecast to be completed and in service in 2023 and 2024 (total forecast cost of $11.084 million added to rate base by end of 2024).

  - **WH1 Head Gate Replacement** – Actual cost of approximately $2.204 million for facilities in service in 2022.

  - **P&C: S250 Callison Protection, Control and SCADA Upgrade** – Forecast cost of approximately $2.125 million in 2023; and forecast to be completed and in service in 2023.

  - **MH0 Road and Road Slope Stability** – Forecast cost of approximately $1.874 million in 2023 with work forecast to be completed and project in service 2023.

  - **Wareham Spillway Concrete Repair** – Actual cost of approximately $0.898 million and $0.447 million for facilities in service to the end of 2021 and 2022 respectively, with forecast cost of $0.5 million in 2023 for facilities forecast to be completed and in service in 2023 (total forecast cost of $1.845 million added to rate base by end of 2023).

  - **Whitehorse Stoplog Crane Replacement** – Forecast cost of approximately $4.247 million, for work forecast to be completed in 2023.

  - **Schwatka Lake Safety/ Debris Boom** – Forecast cost of approximately $1.097 million, for work forecast to be completed in 2023.

  - **Dawson Voltage Conversion** – Forecast cost of approximately $1.872 million in 2024; forecast to be completed and in service in 2024.

  - **Whitehorse Spillway Stoplog Refurbishment** – Forecast cost of approximately $1.000 million, for work forecast to be completed in 2024.

- **Lewes River Boat Lock Road Access Rebuild** – Forecast cost of approximately $1.200 million, for work forecast to be completed in 2024.

- **Changes for Projects Reviewed & Approved in 2021 GRA** – Two capital projects reviewed and approved in Appendix A to Board Order 2022-03 have adjusted rate base for the 2023/24 GRA – total adjustment of $2.728 million added to the rate base previously approved in 2021 GRA:

  - **Mayo-McQuesten Transmission Line Upgrade** – Actual cost of $28.939 million in 2021 offset by contributions of $21.064 million; and actual cost of $0.898 million in 2022, offset by contributions of $0.651 million; the project was completed and in service in 2022 with total actual cost of $29.836, offset by total contributions of $21.715 million (net cost of $8.121 million). Net cost of $8.628 that was added to rate base during the 2021 GRA[1] is reduced by $0.507 million based on final costs and contributions.

  - **Replace P125 WH2 Head Gate** – The Board in the 2021 GRA directed that costs for this project will only be added to approved rate base in the next GRA, based on the actual spending amount incurred. In addition to the actual cost of $2.072 million that the Board previously found reasonable[2], actual additional costs of approximately $0.149 million have been incurred for facilities in service to the end of 2021, i.e., total project costs to be added to approved rate base for the 2023/24 GRA equal $2.221 million.

- **Capital investments on New Supply options to maximize renewable energy generation** – Net rate base impact of approximately $7.867 million addition to 2021 approved rate base:

  - **WH2 Uprate Construction and Engineering** – Actual cost for construction and engineering in 2021 of $12.358 million; and actual construction cost of $0.457 million in 2022. Total in service cost of $12.814 million, of which $5.736 million was approved cost

[1] Board Order 2022-03, Appendix A, para 258.
[2] Board Order 2022-03, Appendix A, para 270.

added to rate base following the 2021 GRA[3] – addition of $7.078 million to 2021 rate base is now sought.

- **WH4 Servomotor Replacement** – Actual cost of $1.318 million in 2021 and $0.019 million in 2022. Total in service cost of $1.337 million at the end of 2022, of which $0.548 million was approved cost added to rate base following the 2021 GRA[4] – addition of $0.789 million to 2021 rate base is now sought.

Excluding the two projects already reviewed and approved in the 2021 GRA (Mayo-McQuesten Transmission Line Upgrade, and Replace P125 WH2 Head Gate), business case summaries for each of the above major capital projects added to rate base in this GRA are reviewed in Appendix 5.1A.

5.2.2 Projects $100,000 to $1 Million

Growth in rate base reflects ongoing need to refurbish old assets and improve grid reliability. Ongoing reinvestment in existing infrastructure ensures that the Yukon integrated grid can continue to meet loads on the system in a safe and reliable manner. PP&E spending for projects less than $1 million was $4.617 million in 2021, $11.573 in 2022, and forecast spending on these project is $12.277 million in 2023 and $8.148 million in 2024 (see Table 5.1). Forecast net rate base additions (after contributions, and before depreciation or amortization deductions) over these four year for PP&E projects with rate base amounts under $1 million total approximate $24.3 million (see Table 5.6, excluding RFID and RFSR).

Business case summaries for each of the projects included in Tables 5.2 to 5.6 with rate base additions between $100,000 and $1 million that come into service between 2021 to 2024 and therefore impact test year rate bases, and net additions to rate base by year by PP&E cost category (i.e., generation, transmission, distribution, and general plant and equipment) are provided in Appendix 5.1B for projects summarized below. Appendix 5.1B business case reviews (and the summary below) also include net rate base additions over $100,000 for overhauls, right of use assets, RFID, and reserve for site restoration.

- **Generation Projects** – There was approximately $1.095 million added to rate base in 2021 on generation projects $100,000 to $1 million; $1.240 million added in 2022; and $0.286 million forecast to be added for the 2023 test year and $1.000 million forecast in the 2024 test year. The total forecast 2024 rate base increase from these generation projects approximates $3.620

[3] Board Order 2022-03, Appendix A, para 278.
[4] Board Order 2022-03, Appendix A, para 282.

million, excluding any depreciation or amortization deductions. Rate base additions relate to the following projects:

- Wareham Spillway – Gate Refurbishment ($0.483 million in 2021);
- Wareham Spillway Stoplogs – New Set ($0.385 million in 2021);
- WH1 & 2 Penstock Repair ($0.227 million in 2021);
- Faro Fuel System ($0.991 million in 2022);
- WH3 Tailrace Gate Certification ($0.249 million in 2022);
- MBH1/2 Seal Water Filtration ($0.286 million in 2023);
- WH4 Air Admission Valve Automation ($0.200 million in 2024);
- WG2 Cylinder Head Swap ($0.500 million in 2024); and
- WG1 Radiator Replacement ($0.300 million in 2024).

- **Transmission Projects** – There was approximately $0.552 million added to rate base in 2021 on transmission projects $100,000 to $1 million; $0.012 million added in 2022; $0.480 million forecast to be added for 2023 test year; and $1.339 million forecast for the 2024 test year. Total 2024 rate base increase from these transmission projects approximates $3.009 million, excluding any depreciation or amortization deductions and before contributions of approximately $0.627 million. Rate base additions relate to the following projects:
  - Transmission Line Access ($0.552 million in 2021);
  - Alexco Mobile Substation Connection & Contributions ($0.193 million in 2021 with a $0.193 million contribution);
  - 177 Re-Route ($0.012 million in 2022; and $0.738 million in 2023 with a $0.434 million contribution);
  - NWTEL Make Ready Work ($0.175 million in 2023);
  - P&C: S170 Protection, Control and SCADA Upgrade ($0.839 million in 2024);
  - L177 Gang Switches ($0.250 million in 2024); and
  - Transmission Line Test and Treat Program ($0.250 million in 2024).
- **Distribution Projects** – There was approximately $0.097 million added to rate base (beyond amounts approved in the 2021 GRA) in 2021 on distribution projects $100,000 to $1 million; $0.078 million added in 2022, $0.237 million forecast to be added for 2023 test year; and $0.200

million forecast for the 2024 test year. Total 2024 rate base increase from these distribution projects approximates $9.642 million, excluding any depreciation or amortization deductions and before total contributions of approximately $9.031 million. Rate base additions relate to the following projects:

- Customer Extensions ($0.943 million in 2021 with a $0.846 million contribution; $0.201 million in 2022 with a $0.123 million contribution; $1.727 million in 2023 with a $1.261 million contribution; and $0.600 million in 2024 with a $0.400 million contribution);
- IPP Connections ($5.205 million in 2023 with a $6.401 million contribution);
- Synchronous Condenser Overhaul ($0.616 million in 2023); and
- Dawson Distribution 3 Phase Loop ($0.350 million in 2023).

- **General Plant and Equipment** – There was approximately $0.412 million added to rate base (beyond amounts approved in the 2021 GRA) in 2021 on General Plant and Equipment projects $100,000 to $1 million; $0.573 million added in 2022; $2.068 million forecast to be added for 2023 test year; and $1.812 million forecast for the 2024 test year. Total 2024 rate base increase from these general plant and equipment projects approximates $4.865 million, excluding any depreciation or amortization deductions. Rate base additions relate to the following projects:
  - Major Crane Asset Replacement/ Refurbishment ($0.293 million in 2021; and $0.700 million in 2024);
  - Server Replacements ($0.119 million in 2021);
  - Aishihik Bridge Re-decking ($0.109 million in 2022);
  - Vehicle Purchases ($0.464 million in 2022; $0.624 million in 2023 and $0.567 million in 2024);
  - New Mobile Office Unit – IT ($0.810 million in 2023);
  - Compact Digger Truck ($0.200 million in 2023);
  - Skid Steer ($0.189 million in 2023);
  - Mayo-McQuesten Radio to Fiber Migration ($0.135 million in 2023);
  - Waste Management Equipment ($0.110 million in 2023);
  - HQ Datacentre Server Replacement ($0.300 million in 2024); and
  - SCADA Operation Network Segregation ($0.245 million in 2024).

- **Overhauls** – Actual overhauls costs exceeding $100,000 approximated $2.341 million in 2022; forecast overhaul costs exceeding $100,000 approximate $3.261 million in 2023 and $0.850 million in 2024. Total 2024 rate base increase from these overhauls approximates $6.452 million, excluding any depreciation or amortization deductions. Rate base additions relate to the following projects:
  - AH2 Overhaul ($2.341 million in 2022);
  - AH1 10 Year Overhaul ($2.461 million in 2023);
  - WG1 Overhaul ($0.400 million in 2023);
  - WG2 Overhaul ($0.400 million in 2023);
  - WG3 Overhaul ($0.400 million in 2024); and
  - DD4 Overhaul ($0.450 million in 2024).
- **Right of Use Assets** – Actual right of use assets costs exceeding $100,000 approximated $1.181 million in 2022; forecast right of use assets costs exceeding $100,000 approximate $0.750 million in 2023. Total 2024 rate base increase from these right of use assets costs approximates $1.931 million, excluding any depreciation or amortization deductions. Rate base additions relate to the following projects:
  - Right of Use Asset Battery Land Lease ($1.004 million in 2022);
  - Right of Use Asset Kulan Land ($0.177 million in 2022); and
  - Right of Use Asset 1 Lindeman Road ($0.750 million in 2023).
- **RFID and Reserve for Site Restoration** – A brief review is provided of cost impacts on these two accounts that are also reported on in Tab 3 of the Application.

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 2021 General Rate Application.

Deferred costs include feasibility studies for a wide range of projects (focused mainly on potential new generation or transmission options), continued relicensing work (this grouping includes water licence renewal activities as well as water licence amendment projects, e.g., Mayo Lake Storage Enhancement Project), regulatory work (includes DSM), and dam safety review work.

Deferred costs additions to rate base net of contributions approximated $0.854 million during 2021 and $4.545 million during 2022, and are forecast at approximately $12.644 million during 2023 and $2.728 million during 2024 (total of approximately $16.5 million over these years - see Table 5.6).

Deferred expenditures in WIP during 2021 through 2024, and not affecting rate base until after 2024, are forecast in total at approximately $28.9 million (see Table 5.7).

5.3.1 Major Deferred Projects >$1 Million – Rate Base Additions

Test year spending on major deferred cost projects focuses 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 future potential generation and transmission requirements.

Total forecast cost to be added to net rate base for major deferred cost projects by the end of 2024 is approximately $16.037 million. Each major project added to rate base is reviewed separately in Appendix 5.2A (see also Tables 5.3 to 5.6 at the end of Tab 5):

- **Spending on Sustaining Capital** – Net rate base impact of approximately $4.479 million, excluding reductions due to amortization:
    - **Aishihik Relicensing (Five Year Licence Renewal)** - ($3.903 million expenditure in 2022 and $0.575 million in 2023, with $4.479 million net increase in rate base by the end of 2023, excluding reductions due to amortization).
- **Spending on planning to meet other future Generation and Transmission Requirements** – Net rate base impact of approximately $11.558 million by the end of 2024, excluding reductions due to amortizations:
    - **Demand Side (DSM) Program Development and DSM Program 2022-2030** – ($2.774 million net increase in rate base by the end of 2024, after contributions of $1.163 million but excluding reductions due to amortization).
    - **Southern Lakes Storage** ($8.784 million addition to rate base at the end of 2023, excluding reductions due to amortization).

5.3.2 Deferred Projects between $100,000 and $1 Million – Rate Base Additions

The projected total test year spending in deferred cost activities impacting rate base additions, excluding major projects over $1 million (as described in Section 5.3.1), totals approximately $0.843 million in 2021, $0.288 million in 2022, $2.034 million in 2023 and $1.568 million in 2024, as set out in detail in Tables 5.2 to 5.6. Total increase to rate base over these years from deferred cost activities excluding major projects over $1 million, but including transfers from WIP spending prior to 2024, is approximately $4.7 million in 2024 (excluding reductions due to amortizations).

Appendix 5.2B summarizes deferred cost projects over $100,000 but less than $1 million that will be added to rate base in the test years. Details on project costs are summarized in Tables 5.3 to 5.6. Rate base additions from 2021 to 2024 in each deferred cost activity totaling between $100,000 and $1 million that impact 2024 rate base are summarized below (total rate base impact in 2024 test year of approximately $3.716 million, excluding reductions due to amortization, reflecting $0.581 million additions in 2021, $0.115 million additions in 2022, $1.692 million additions in 2023, and $1.328 million additions in 2024).

- **Feasibility Studies – Reliability & Asset Improvements**. Rate base additions of approximately $2.229 million for the following projects:
  - Whitehorse Post-Flood Assessment ($0.115 million in 2022);
  - Mayo Civil Infrastructure Refurbishment Planning ($0.168 million in 2023);
  - System Wide Arc Flash Study ($0.198 million in 2023);
  - System Wide Stability Study ($0.200 million in 2023);
  - Digital Strategy and Policy Development ($0.120 million in 2023);
  - Privacy Management Program ($0.100 million in 2023);
  - Cyber Security Framework ($0.140 million in 2024);
  - WRGS Thermal Assessment & Permitting ($0.413 million in 2024);
  - Transmission Line Detailed Inspection Program ($0.250 million in 2024);
  - Gates/TIVs Certification Assessment System Wide ($0.200 million in 2024);
  - Digital Reporting Review ($0.125 million in 2024);
  - Records Policy Planning and Program Development ($0.100 million in 2024); and

  - Breaker Condition Assessment ($0.100 million in 2024).

- **Regulatory and Dam Safety Review**: Rate base additions of approximately $1.486 million for the following projects:

  - Dam Safety Review ($0.255 million in 2021);
  - IPP Standing Offer Implementation ($0.326 million in 2021, $0.070 million in 2023);
  - Atlin EPA Section 18 Proceeding (Hearing Reserve Account) ($0.386 million in 2023);
  - Public Safety Plans ($0.225 million in 2023); and
  - Vegetation Management Plan Update ($0.225 million in 2023).

5.4 INTANGIBLE ASSETS

An intangible asset is a non-monetary asset without physical substance and that is identifiable (either being separable or arising from contractual or other legal rights). It is a resource that is controlled by an entity as a result of past events (for example, purchase or self-creation) and from which future economic benefits (inflows of cash or other assets) are expected. Examples include patented technology, computer software and databases.

Intangible assets impacting test year rate base additions are reviewed in Tables 5.2 to 5.6 and include costs related to development of an asset management framework (i.e., PAMMS Asset Management Framework and Enterprise Asset Management Purchase and Implementation), as well as smaller projects relating to EAM Enhancement review, CIS replacement, P&C Central Event Data Collection System and SharePoint Upgrades. Two major projects (i.e., costs exceeding $1 million) are summarized in Section 5.4.1 below and reviewed in detail in Appendix 5.3A. Intangible assets with costs greater than $100,000 (but less than $1 million) that are included in rate base before the end of 2024 are summarized in Section 5.4.2 below and reviewed in more detail in Appendix 5.3B.

5.4.1 Major Projects > $1 Million – Rate Base Additions

Test year spending on Intangible Assets over $1 million relate to the PAMMS Asset Management Framework and related implementation of the Enterprise Management System purchase and implementation. As summarized below and in Tables 5.2 to 5.5, and reviewed for each project in more detail in Appendix 5.3A, total forecast spending included in rate base by the end of 2024 for these two projects is approximately $10.006 million:

- **PAMMS Asset Management Framework** – Rate base addition of $5.466 million in 2023 – approximate expenditures $0.439 million in 2018, $1.349 million in 2019, $1.530 million in 2020, $0.303 million in 2021, $0.835 million in 2022 and $1.011 million in 2023.

- **Enterprise Asset Management (EAM) System Purchase and Implementation –** Rate base addition of $4.550 million in 2021 – approximate expenditures $0.276 million in 2018, $0.534 million in 2019, $2.972 million in 2020 and $0.768 million in 2021.

5.4.2 Intangible Projects between $100,000 and $1 Million – Rate Base Additions

Appendix 5.3B summarizes intangible assets cost projects over $100,000 but less than $1 million that will be added to rate base before the end of 2024. Details on project costs are summarized in Tables 5.3 to 5.6.

Rate base additions from 2021 to 2024 in each intangible assets cost activity totaling between $100,000 and $1 million that impact 2024 rate base are summarized below (total rate base impact in 2024 test year of approximately $0.766 million, excluding reductions due to amortization, reflecting $0.147 million additions in 2022, $0.368 million additions in 2023, and $0.250 million additions in 2024). These rate base additions relate to the following projects:

- EAM Enhancements Review ($0.147 million in 2022);
- Network Software Traffic Shaping ($0.250 million in 2023);
- CIS Replacement ($0.118 million in 2023);
- P&C Central Event Data Collection System ($0.150 million in 2024); and
- SharePoint Upgrades ($0.100 million in 2024).

YUKON ENERGY CORPORATION 2023/24 GRA **Table 5.1**
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT - SUMMARY **August 2023**
($000S)

Description	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
SUMMARY - RECONCILIATION OF PROPERTY, PLANT AND EQUIPMENT				
Work in Progress (WIP), Beginning of Year	25,295	3,808	33,638	81,644
Transfers		3,247		
Work in Progress (WIP), Beginning of Year	25,295	7,055	33,638	81,644
Total Major Projects	23,088	32,741	68,563	56,690
Ongoing Maintenance Capital				
Total Generation	1,735	565	520	1,560
Total Transmission	253	452	1,104	1,179
Total Distribution	996	3,390	2,800	1,005
Total General Plant & Equipment	716	1,488	2,596	2,872
Right of Use Assets	0	1,181	750	0
Total Overhaul	0	2,372	3,230	850
Total RFID	916	2,086	554	682
Total RFSR	0	40	723	0
Subtotal Ongoing Capital	4,617	11,573	12,277	8,148
Total Expenditures	27,705	44,315	80,840	64,838
Transfer to RFID/RFSR	-916	-2,126	-1,277	-682
Other Adjustments				
Total WIP Adjustments and Transfers	-916	-2,126	-1,277	-682
Transfer to Ratebase	-48,275	-15,606	-31,557	-45,222
WIP end of year	**3,808**	**33,638**	**81,644**	**100,578**
Opening PPE in-service	642,667	687,789	701,616	731,503
Net transfer from WIP	48,275	12,359	31,557	45,222
Retirements and other adjustments	-3,153	1,468	-1,671	-2
Closing PPE in-service	**687,789**	**701,616**	**731,503**	**776,723**
Opening Total PPE (in-service plus WIP)	667,962	691,598	735,254	813,146
Change to total PPE	23,636	43,656	77,892	64,154
Closing total PPE	**691,598**	**735,254**	**813,146**	**877,301**
RECONCILIATION OF CUSTOMER CONTRIBUTIONS				
Opening Customer Contributions WIP	**13,361**	**1,386**	**12,788**	**16,500**
Customer Contributions Received	10,128	10,788	11,807	4,900
Adjustments				
less: transfer to Rate Base	-22,104	614	-8,095	-400
Customer Contributions WIP end of year	**1,386**	**12,788**	**16,500**	**21,000**
Opening Gross Customer Contributions in Service	**211,830**	**233,917**	**234,687**	**242,782**
Transfers from WIP	22,104	-614	8,095	400
Retirements, Disposals and Adjustments	-16	1,384	0	0
Closing Gross Customer Contributions in Service	**233,917**	**234,687**	**242,782**	**243,182**
Opening Total Contribution (in-service plus WIP)	225,191	235,303	247,475	259,282
Change to total Contribution	10,112	12,172	11,807	4,900
Closing total Contribution	235,303	247,475	259,282	264,182

YUKON ENERGY CORPORATION 2023/24 GRA **Table 5.2**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2021 **August 2023**
($000S)

	Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
	Capital Projects – Major projects > $1 million – Rate Base Additions				
	Whitehorse Interconnection	0.0	508.0	0.0	508.0
	Transmission Line Replacement L178	0.0	311.1	-311.1	0.0
	Dawson Voltage Conversion	67.6	2.4	0.0	70.0
	Whitehorse Stoplog Crane Replacement	0.0	88.0	0.0	88.0
	MH0 Road & Road Slope Stability	0.0	13.3	0.0	13.3
	WH4 Servomotor Replacement	384.7	933.5	-1,318.2	0.0
	WH2 Uprate Construction	3,910.3	8,182.0	-12,092.3	0.0
	WH2 Uprate Engineering	259.1	6.4	-265.4	0.0
	Mayo - McQuesten Transmission Line Upgrade	17,487.1	11,451.5	-28,938.6	0.0
	Mayo - McQuesten Contributions	-12,379.4	-8,684.8	21,064.3	0.0
*	Replace P125 WH2 Head Gate	128.7	20.5	-149.2	0.0
	Wareham Spillway Concrete Repair	192.4	705.6	-898.1	0.0
	WH1 Headgate Replacement	0.0	11.3	0.0	11.3
	Subtotal	**10,050.5**	**13,548.6**	**-22,908.6**	**690.5**
	Capital Projects – Projects $100,000 to $1 million - Rate Base Additions				
	Generation				
	Faro Fuel System	0.0	840.6	0.0	840.6
	Wareham Spillway Stoplogs - New Set	0.0	385.2	-385.2	0.0
	WH3 Tailrace Gate Certification	0.0	207.5	0.0	207.5
	WH1&2 Penstock Repair	0.0	226.7	-226.7	0.0
	Wareham Spillway - Gate Refurbishment	146.3	336.5	-482.8	0.0
	Other Projects with <$100k Spending	257.5	218.0	-311.8	163.7
	Subtotal	**403.8**	**2,214.5**	**-1,406.4**	**1,211.8**
	Transmission				
	Transmission Line Access	541.9	9.6	-551.5	0.0
	Alexco Mobile Substation Connection	72.5	120.9	-193.4	0.0
	Alexco Mobile Substation Connection Contributions	-72.5	-120.7	193.2	0.0
	L177 Re Route	0.0	11.4	0.0	11.4
	Other Projects with <$100k Spending	-85.6	111.5	-25.9	0.0
	Subtotal	**456.3**	**132.7**	**-577.6**	**11.4**
	Distribution				
	Customer Extensions	704.1	947.1	-942.9	708.3
	Customer Extensions Customer Contributions	-592.7	-741.6	846.1	-488.2
	Synchronous Condenser Overhaul	24.7	0.6	0.0	25.3
	Other Projects with <$100k Spending	0.0	48.4	-48.4	0.0
	Subtotal	**136.2**	**254.5**	**-145.3**	**245.4**
	General Plant				
	Major Crane Assessment/Refurbishment	0.0	292.8	-292.8	0.0
	Server Replacements	100.1	18.8	-118.9	0.0
	Other Projects with <$100k Spending	99.0	404.5	-502.8	0.7
	Subtotal	**199.1**	**716.1**	**-914.5**	**0.7**
	RFID				
	RFID	4,441.0	3,841.8	-1,393.3	6,075.6
	RFID Contributions	-2,974.1	-2,925.3	0.0	-5,899.4
	Subtotal	**1,467.0**	**916.5**	**-1,393.3**	**176.2**

YUKON ENERGY CORPORATION 2023/24 GRA
WORK IN PROGRESS CONTINUITY SCHEDULE - 2021
($000S)

Table 5.2
August 2023

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Deferred Costs – Major projects > $1 million – Rate Base Additions				
DSM Program Development	1,014.1	245.8	-10.4	1,249.5
DSM Program Development Contributions	-854.2	-249.8	0.0	-1,104.1
** Thermal Replacement (16.5 MW)	1,071.0	752.2	0.0	1,823.2
** IPP Connections	51.0	1,372.7	0.0	1,423.7
** IPP Connections Customer Contributions	-50.5	-1,337.4	0.0	-1,387.8
Southern Lakes Storage	7,938.9	561.1	0.0	8,500.0
Aishihik 5-Year License Renewal	7,627.3	1,273.1	0.0	8,900.3
Subtotal	**16,797.6**	**2,617.8**	**-10.4**	**19,404.9**
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions				
GRA 2020-2021 (Hearing Reserve Acct)	370.2	454.8	0.0	825.0
IPP Standing Offer Program Implementation	280.1	45.9	-326.0	0.0
Dam Safety Review	173.6	80.9	-254.5	0.0
Other Projects with <$100k Spending	129.5	153.2	-262.8	19.9
Subtotal	**953.3**	**734.8**	**-843.3**	**844.9**
Intangible Assets – Major projects > $1 million - Rate Base Additions				
PAMMS Asset Management Framework	3,317.7	302.8	0.0	3,620.5
EAM Purchase and Implementation	3,781.6	768.3	-4,549.9	0.0
Subtotal	**7,099.3**	**1,071.1**	**-4,549.9**	**3,620.5**
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions				
Other Projects with <$100k Spending	41.1	57.6	-98.8	0.0
Subtotal	**41.1**	**57.6**	**-98.8**	**0.0**
Total	**37,604.2**	**22,264.2**	**-32,848.0**	**26,206.4**
Total Major Projects [before contributions]	22,429.9	22,233.5	-43,972.9	690.5
Maintenance Capital [before contributions]				
Total Generation	403.8	2,214.5	-1,406.4	1,211.8
Total Transmission	528.8	253.4	-770.8	11.4
Total Distribution	728.9	996.2	-991.3	733.7
Total General Plant & Equipment	199.1	716.1	-914.5	0.7
Capital Contributions	-13,044.6	-9,547.1	22,103.5	-488.2
Right of Use Assets	0.0	0.0	0.0	0.0
Total Overhaul	0.0	0.0	0.0	0.0
Total Net RFID	1,467.0	916.5	-1,393.3	176.2
Deferred Costs [before contributions]	18,655.6	4,939.7	-853.6	22,741.7
Deferred Cost Contributions	-904.7	-1,587.2	0.0	-2,491.9
Intangible Assets	7,140.4	1,128.7	-4,648.6	3,620.5
Total	**37,604.2**	**22,264.2**	**-32,848.0**	**26,206.4**

Notes:
* Total project cost at $2.072 million including $1.923 million closed in 2020 and $0.149 million closed in 2021.
** In 2021 Thermal Replacement Project and IPP Connections Projects were under Deferred costs.

YUKON ENERGY CORPORATION 2023/24 GRA **Table 5.3**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2022 **August 2023**
($000S)

	Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
	Capital Projects – Major projects > $1 million – Rate Base Additions				
*	Thermal Replacement (16.5 MW)	1,823.2	4,624.2	-150.1	6,297.3
	Whitehorse Interconnection	508.0	7,895.9	0.0	8,403.9
	Transmission Line Replacement L178	0.0	4,772.4	-4,772.4	0.0
	Dawson Voltage Conversion	70.0	1.8	0.0	71.8
	Whitehorse Stoplog Crane Replacement	88.0	234.8	0.0	322.8
	MH0 Road & Road Slope Stability	13.3	921.1	0.0	934.4
	WH4 Servomotor Replacement	0.0	18.9	-18.9	0.0
	WH2 Uprate Construction	0.0	456.6	-456.6	0.0
	Mayo - McQuesten Transmission Line Upgrade	0.0	897.8	-897.8	0.0
	Mayo - McQuesten Contributions	0.0	-650.7	650.7	0.0
	P&C: S250 Callison Protection, Control and SCADA Upgrad	0.0	388.1	0.0	388.1
	Schwatka Lake Safety/Debris Boom	0.0	581.2	0.0	581.2
	Wareham Spillway Concrete Repair	0.0	446.9	-446.9	0.0
	WH1 Headgate Replacement	11.3	2,192.5	-2,203.8	0.0
	Subtotal	**2,513.7**	**22,781.6**	**-8,295.9**	**16,999.4**
	Capital Projects – Projects $100,000 to $1 million - Rate Base Additions				
	Generation				
	Faro Fuel System	840.6	150.2	-990.8	0.0
	WH3 Tailrace Gate Certification	207.5	41.4	-248.9	0.0
	Other Projects with <$100k Spending	163.7	224.6	-306.9	81.4
	Subtotal	**1,211.8**	**416.2**	**-1,546.6**	**81.4**
	Transmission				
	L177 Re Route	11.4	304.9	-11.7	304.7
	Other Projects with <$100k Spending	0.0	146.9	-132.4	14.4
	Subtotal	**11.4**	**451.8**	**-144.1**	**319.1**
	Distribution				
	Customer Extensions	708.3	619.6	-200.9	1,127.1
	Customer Extensions Customer Contributions	-488.2	-495.4	123.0	-860.7
*	IPP Connections	1,423.7	2,281.6	0.0	3,705.3
*	IPP Connections Customer Contributions	-1,387.8	-3,513.1	0.0	-4,900.9
	Synchronous Condenser Overhaul	25.3	390.9	0.0	416.3
	Other Projects with <$100k Spending	0.0	97.9	-97.9	0.0
	Subtotal	**281.3**	**-618.5**	**-175.8**	**-513.0**
	General Plant				
	Vehicle Purchases	0.2	463.8	-464.0	0.0
	New Mobile Office Unit - IT	0.0	185.2	0.0	185.2
	Aishihik Bridge Redecking	0.0	109.3	-109.3	0.0
	Other Projects with <$100k Spending	0.4	729.2	-575.3	154.3
	Subtotal	**0.7**	**1,487.5**	**-1,148.6**	**339.6**
	Overhaul				
	AH1 10 Year Overhaul	0.0	31.0	0.0	31.0
	AH2 Overhaul	0.0	2,340.9	-2,340.9	0.0
	Subtotal	**0.0**	**2,371.8**	**-2,340.9**	**31.0**
	Right of Use Assets				
	Right of Use Asset Battery Land Lease	0.0	1,003.8	-1,003.8	0.0
	Right of Use Asset Kulan Land	0.0	177.1	-177.1	0.0
	Subtotal	**0.0**	**1,180.9**	**-1,180.9**	**0.0**
	RFID				
	RFID	6,075.6	2,085.8	-7,815.5	345.9
	RFID Contributions	-5,899.4	0.0	5,899.4	0.0
	Subtotal	**176.2**	**2,085.8**	**-1,916.1**	**345.9**

YUKON ENERGY CORPORATION 2023/24 GRA **Table 5.3**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2022 **August 2023**
($000S)

	Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
	Reserve for Site Restoration				
	Reserve for Site Restoration Bucket	0.0	40.1	0.0	40.1
	Subtotal	**0.0**	**40.1**	**0.0**	**40.1**
	Deferred Costs – Major projects > $1 million – Rate Base Additions				
	DSM Program 2022-2030	0.0	64.2	-64.2	0.0
	DSM Program Development	1,249.5	181.3	-1,430.8	0.0
	DSM Program Development Contributions	-1,104.1	-37.6	1,141.6	0.0
	Southern Lakes Storage	8,500.0	284.1	0.0	8,784.2
***	Aishihik 5-Year License Renewal	8,900.3	-4,421.5	-3,903.4	575.4
	Subtotal	**17,545.8**	**-3,929.5**	**-4,256.8**	**9,359.5**
	Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions				
	Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)	0.0	253.9	0.0	253.9
	Mayo Civil Infrastructure Refurbishment Planning	0.0	168.4	0.0	168.4
	System Wide Arc Flash Study	0.0	147.7	0.0	147.7
	Whitehorse Post-Flood Assessment	0.0	115.2	-115.2	0.0
	GRA 2020-2021 (Hearing Reserve Acct)	825.0	-801.8	0.0	23.1
	IPP Standing Offer Program Implementation	0.0	70.3	0.0	70.3
	Other Projects with <$100k Spending	19.9	152.7	-172.6	0.0
	Subtotal	**844.9**	**106.4**	**-287.9**	**663.5**
	Intangible Assets – Major projects > $1 million - Rate Base Additions				
	PAMMS Asset Management Framework	3,620.5	834.6	0.0	4,455.2
	Subtotal	**3,620.5**	**834.6**	**0.0**	**4,455.2**
	Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions				
	EAM Enhancements Review	0.0	147.3	-147.3	0.0
	CIS Replacement	0.0	3.3	0.0	3.3
	Other Projects with <$100k Spending	0.0	133.8	-131.0	2.8
	Subtotal	**0.0**	**284.4**	**-278.3**	**6.1**
	Total	**26,206.4**	**27,493.2**	**-21,571.8**	**32,127.8**
	Total Major Projects [before contributions]	2,513.7	23,432.2	-8,946.6	16,999.4
	Maintenance Capital [before contributions]				
	Total Generation	1,211.8	416.2	-1,546.6	81.4
	Total Transmission	11.4	451.8	-144.1	319.1
	Total Distribution	2,157.4	3,390.0	-298.8	5,248.6
	Total General Plant & Equipment	0.7	1,487.5	-1,148.6	339.6
	Capital Contributions	-1,876.1	-4,659.2	773.7	-5,761.6
	Right of Use Assets	0.0	1,180.9	-1,180.9	0.0
	Total Overhaul	0.0	2,371.8	-2,340.9	31.0
	Total Net RFID	176.2	2,085.8	-1,916.1	345.9
	Total Net RFSR	0.0	40.1	0.0	40.1
	Deferred Costs [before contributions]	19,494.8	-3,785.5	-5,686.3	10,023.0
	Deferred Cost Contributions	-1,104.1	-37.6	1,141.6	0.0
	Intangible Assets	3,620.5	1,119.1	-278.3	4,461.3
	Total	**26,206.4**	**27,493.2**	**-21,571.8**	**32,127.8**

Notes:
* In 2021 Thermal Replacement Project and IPP Connections Projects were under Deferred costs. The $0.150 million Thermal Replacement Project adjustment reflects the closed cost to feasibility deferred costs.
** Reflects $1.3 million spending in 2022 and $5.7 million transfer to long-term relicensing project [25-year license].

YUKON ENERGY CORPORATION 2023/24 GRA — **Table 5.4**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2023 — **August 2023**
($000S)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Capital Projects – Major projects > $1 million – Rate Base Additions				
Thermal Replacement (16.5 MW)	6,297.3	28,650.0	0.0	34,947.3
Whitehorse Interconnection	8,403.9	2,295.0	0.0	10,698.9
Whitehorse Stoplog Crane Replacement	322.8	3,923.9	-4,246.7	0.0
MH0 Road & Road Slope Stability	934.4	940.0	-1,874.4	0.0
Transmission Line Replacement L178	0.0	1,000.0	-1,000.0	0.0
2023 Mayo-Faro Diesel Infrastructure	0.0	4,300.0	-4,300.0	0.0
P&C: S250 Callison Protection, Control and SCADA Upgrad	388.1	1,736.8	-2,124.9	0.0
Dawson Voltage Conversion	71.8	600.0	0.0	671.8
Wareham Spillway Concrete Repair	0.0	500.0	-500.0	0.0
Schwatka Lake Safety/Debris Boom	581.2	515.5	-1,096.8	0.0
Subtotal	**16,999.4**	**44,461.2**	**-15,142.7**	**46,317.9**
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions				
Generation				
MBH1/2 Seal Water Filtration	10.7	275.0	-285.7	0.0
Other Projects with <$100k Spending	70.7	185.0	-255.7	0.0
Subtotal	**81.4**	**460.0**	**-541.4**	**0.0**
Transmission				
P&C: S170 Protection, Control and SCADA Upgrade	0.0	405.0	0.0	405.0
L177 Re Route	304.7	433.6	-738.3	0.0
L177 Re Route Contributions	0.0	-433.6	433.6	0.0
NWTEL Make Ready Work	0.0	175.0	-175.0	0.0
Other Projects with <$100k Spending	14.4	90.0	-104.4	0.0
Subtotal	**319.1**	**670.0**	**-584.1**	**405.0**
Distribution				
Customer Extensions	1,127.1	600.0	-1,727.1	0.0
Customer Extensions Customer Contributions	-860.7	-400.0	1,260.7	0.0
IPP Connections	3,705.3	1,500.0	-5,205.3	0.0
IPP Connections Customer Contributions	-4,900.9	-1,500.0	6,400.9	0.0
Synchronous Condenser Overhaul	416.3	200.0	-616.3	0.0
Dawson Distribution 3 Phase Loop	0.0	350.0	-350.0	0.0
Other Projects with <$100k Spending	0.0	150.0	-150.0	0.0
Subtotal	**-513.0**	**900.0**	**-387.0**	**0.0**
General Plant				
New Mobile Office Unit - IT	185.2	625.0	-810.2	0.0
Vehicle Purchases	0.0	623.8	-623.8	0.0
Compact Digger Truck	0.4	200.0	-200.4	0.0
Skid Steer	0.0	189.0	-189.0	0.0
Mayo-McQuesten Radio to Fiber Migration	89.6	45.0	-134.6	0.0
Waste Management Equipment	0.0	110.0	-110.0	0.0
HQ Datacenter Server Replacement	0.0	20.0	0.0	20.0
SCADA Operation Network Segregation	0.0	120.0	0.0	120.0
Other Projects with <$100k Spending	64.3	663.3	-727.5	0.0
Subtotal	**339.6**	**2,596.1**	**-2,795.6**	**140.0**
Overhaul				
AH1 10 Year Overhaul	31.0	2,430.0	-2,461.0	0.0
WG1 Overhaul	0.0	400.0	-400.0	0.0
WG2 Overhaul	0.0	400.0	-400.0	0.0
Subtotal	**31.0**	**3,230.0**	**-3,261.0**	**0.0**
Right of Use Assets				
Right of Use Asset 1 Lindeman Road	0.0	750.1	-750.1	0.0
Subtotal	**0.0**	**750.1**	**-750.1**	**0.0**
RFID				
RFID	345.9	554.0	-899.9	0.0
Subtotal	**345.9**	**554.0**	**-899.9**	**0.0**

YUKON ENERGY CORPORATION 2023/24 GRA — **Table 5.4**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2023 — **August 2023**
($000S)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Reserve for Site Restoration				
Reserve for Site Restoration Bucket	40.1	723.0	-763.1	0.0
Subtotal	**40.1**	**723.0**	**-763.1**	**0.0**
Deferred Costs – Major projects > $1 million – Rate Base Additions				
DSM Program 2022-2030	0.0	1,271.6	-1,271.6	0.0
DSM Program Development Contributions	0.0	-21.6	21.6	0.0
Southern Lakes Storage	8,784.2	0.0	-8,784.2	0.0
Aishihik 5-Year License Renewal	575.4	0.0	-575.4	0.0
Subtotal	**9,359.5**	**1,250.0**	**-10,609.5**	**0.0**
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions				
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)	253.9	131.7	-385.6	0.0
WRGS Thermal Assessment & Permitting	0.0	413.0	0.0	413.0
Public Safety Plans	0.0	225.0	-225.0	0.0
System Wide Stability Study	0.0	200.0	-200.0	0.0
System Wide Arc Flash Study	147.7	50.0	-197.7	0.0
Mayo Civil Infrastructure Refurbishment Planning	168.4	0.0	-168.4	0.0
Digital Strategy and Policy Development	0.0	120.0	-120.0	0.0
Privacy Management Program	0.0	100.0	-100.0	0.0
Vegetation Management Plan Update	0.0	225.0	-225.0	0.0
IPP Standing Offer Program Implementation	70.3	0.0	-70.3	0.0
Other Projects with <$100k Spending	23.1	359.0	-342.2	40.0
Subtotal	**663.5**	**1,823.8**	**-2,034.2**	**453.0**
Intangible Assets – Major projects > $1 million - Rate Base Additions				
PAMMS Asset Management Framework	4,455.2	1,011.0	-5,466.2	0.0
Subtotal	**4,455.2**	**1,011.0**	**-5,466.2**	**0.0**
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions				
Network Software Traffic Shaping	0.0	250.0	-250.0	0.0
CIS Replacement	3.3	115.0	-118.3	0.0
Other Projects with <$100k Spending	2.8	70.0	-72.8	0.0
Subtotal	**6.1**	**435.0**	**-441.1**	**0.0**
Total	**32,127.8**	**58,864.2**	**-43,676.0**	**47,315.9**
Total Major Projects [before contributions]	16,999.4	44,461.2	-15,142.7	46,317.9
Maintenance Capital [before contributions]				
Total Generation	81.4	460.0	-541.4	0.0
Total Transmission	319.1	1,103.6	-1,017.7	405.0
Total Distribution	5,248.6	2,800.0	-8,048.6	0.0
Total General Plant & Equipment	339.6	2,596.1	-2,795.6	140.0
Capital Contributions	-5,761.6	-2,333.6	8,095.2	0.0
Right of Use Assets	0.0	750.1	-750.1	0.0
Total Overhaul	31.0	3,230.0	-3,261.0	0.0
Total Net RFID	345.9	554.0	-899.9	0.0
Total Net RFSR	40.1	723.0	-763.1	0.0
Deferred Costs [before contributions]	10,023.0	3,095.4	-12,665.4	453.0
Deferred Cost Contributions	0.0	-21.6	21.6	0.0
Intangible Assets	4,461.3	1,446.0	-5,907.3	0.0
Total	**32,127.8**	**58,864.2**	**-43,676.0**	**47,315.9**

YUKON ENERGY CORPORATION 2023/24 GRA — **Table 5.5**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2024 — **August 2023**
($000S)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Capital Projects – Major projects > $1 million – Rate Base Additions				
Thermal Replacement (16.5 MW)	34,947.3	13,000.0	-18,175.5	29,771.9
Whitehorse Interconnection	10,698.9	500.0	-11,198.9	0.0
Transmission Line Replacement L178	0.0	5,000.0	-5,000.0	0.0
Dawson Voltage Conversion	671.8	1,200.0	-1,871.8	0.0
Whitehorse Spillway Stoplog Refurbishment	0.0	1,000.0	-1,000.0	0.0
Lewes River Boat Lock Road Access Rebuild	0.0	1,200.0	-1,200.0	0.0
Subtotal	**46,317.9**	**21,900.0**	**-38,446.1**	**29,771.9**
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions				
Generation				
WH4 Air Admission Valve Automation	0.0	200.0	-200.0	0.0
WG2 Cylinder Heads Swap	0.0	500.0	-500.0	0.0
WG1 Radiator Replacement	0.0	300.0	-300.0	0.0
Other Projects with <$100k Spending	0.0	75.0	-75.0	0.0
Subtotal	**0.0**	**1,075.0**	**-1,075.0**	**0.0**
Transmission				
P&C: S170 Protection, Control and SCADA Upgrade	405.0	434.0	-839.0	0.0
L177 Gang Switches	0.0	250.0	-250.0	0.0
Transmission Line Test and Treat Program 2020-22	0.0	250.0	-250.0	0.0
Other Projects with <$100k Spending	0.0	145.0	-145.0	0.0
Subtotal	**405.0**	**1,079.0**	**-1,484.0**	**0.0**
Distribution				
Customer Extensions	0.0	600.0	-600.0	0.0
Customer Extensions Customer Contributions	0.0	-400.0	400.0	0.0
Other Projects with <$100k Spending	0.0	155.0	-155.0	0.0
Subtotal	**0.0**	**355.0**	**-355.0**	**0.0**
General Plant				
Major Crane Assessment/Refurbishment	0.0	700.0	-700.0	0.0
Vehicle Purchases	0.0	567.0	-567.0	0.0
HQ Datacenter Server Replacement	20.0	280.0	-300.0	0.0
SCADA Operation Network Segregation	120.0	125.0	-245.0	0.0
Other Projects with <$100k Spending	0.0	800.0	-800.0	0.0
Subtotal	**140.0**	**2,472.0**	**-2,612.0**	**0.0**
Overhaul				
WG3 Overhaul	0.0	400.0	-400.0	0.0
DD4 Overhaul	0.0	450.0	-450.0	0.0
Subtotal	**0.0**	**850.0**	**-850.0**	**0.0**
RFID				
RFID	0.0	681.7	-681.7	0.0
Subtotal	**0.0**	**681.7**	**-681.7**	**0.0**

YUKON ENERGY CORPORATION 2023/24 GRA **Table 5.5**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2024 **August 2023**
($000S)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Deferred Costs – Major projects > $1 million – Rate Base Additions				
DSM Program 2022-2030	0.0	1,160.0	-1,160.0	0.0
Subtotal	**0.0**	**1,160.0**	**-1,160.0**	**0.0**
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions				
WRGS Thermal Assessment & Permitting	413.0	0.0	-413.0	0.0
Cyber Security Framework	40.0	100.0	-140.0	0.0
Transmission Line Detailed Inspection Program	0.0	250.0	-250.0	0.0
Gates/TIV's Certification Assessment System Wide	0.0	200.0	-200.0	0.0
Digital Reporting Review	0.0	125.0	-125.0	0.0
Records Policy Planning and Program Development	0.0	100.0	-100.0	0.0
Breaker Condition Assessment	0.0	100.0	-100.0	0.0
Other Projects with <$100k Spending	0.0	-10.0	10.0	0.0
Subtotal	**453.0**	**865.0**	**-1,318.0**	**0.0**
Intangible Assets – Major projects > $1 million - Rate Base Additions				
Subtotal	**0.0**	**0.0**	**0.0**	**0.0**
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions				
P&C Central Event Data Collection System	0.0	150.0	-150.0	0.0
SharePoint Upgrades	0.0	100.0	-100.0	0.0
Other Projects with <$100k Spending	0.0	130.0	-130.0	0.0
Subtotal	**0.0**	**380.0**	**-380.0**	**0.0**
Total	**47,315.9**	**30,817.7**	**-48,361.8**	**29,771.9**

Total Major Projects [before contributions]	46,317.9	21,900.0	-38,446.1	29,771.9
Maintenance Capital [before contributions]				
Total Generation	0.0	1,075.0	-1,075.0	0.0
Total Transmission	405.0	1,079.0	-1,484.0	0.0
Total Distribution	0.0	755.0	-755.0	0.0
Total General Plant & Equipment	140.0	2,472.0	-2,612.0	0.0
Capital Contributions	0.0	-400.0	400.0	0.0
Right of Use Assets	0.0	0.0	0.0	0.0
Total Overhaul	0.0	850.0	-850.0	0.0
Total Net RFID	0.0	681.7	-681.7	0.0
Deferred Costs [before contributions]	453.0	2,025.0	-2,478.0	0.0
Deferred Cost Contributions	0.0	0.0	0.0	0.0
Intangible Assets	0.0	380.0	-380.0	0.0
Total	**47,315.9**	**30,817.7**	**-48,361.8**	**29,771.9**

YUKON ENERGY CORPORATION 2023/24 GRA **Table 5.6**
SUMMARY OF COMPLETED PROJECTS FOR 2021-2024 YEARS **August 2023**
($000S)

	Completed Projects ($000)				
	2021	**2022**	**2023**	**2024**	**Total**
Capital Projects – Major projects > $1 million – Rate Base Additions					
Thermal Replacement (16.5 MW)	-	150.1	-	18,175.5	18,325.6
Whitehorse Interconnection	-	-	-	11,198.9	11,198.9
Transmission Line Replacement L178	311.1	4,772.4	1,000.0	5,000.0	11,083.5
Dawson Voltage Conversion	-	-	-	1,871.8	1,871.8
Whitehorse Stoplog Crane Replacement	-	-	4,246.7	-	4,246.7
MH0 Road & Road Slope Stability	-	-	1,874.4	-	1,874.4
WH4 Servomotor Replacement	1,318.2	18.9	-	-	1,337.1
WH2 Uprate Construction	12,092.3	456.6	-	-	12,548.9
WH2 Uprate Engineering	265.4	-	-	-	265.4
Mayo - McQuesten Transmission Line Upgrade	28,938.6	897.8	-	-	29,836.4
Mayo - McQuesten Contributions	(21,064.3)	(650.7)	-	-	(21,715.0)
Replace P125 WH2 Head Gate	149.2	-	-	-	149.2
WH1 Headgate Replacement	-	2,203.8	-	-	2,203.8
2023 Mayo-Faro Diesel Infrastructure	-	-	4,300.0	-	4,300.0
P&C: S250 Callison Protection, Control and SCADA Upgrade	-	-	2,124.9	-	2,124.9
Schwatka Lake Safety/Debris Boom	-	-	1,096.8	-	1,096.8
Wareham Spillway Concrete Repair	898.1	446.9	500.0	-	1,845.0
Whitehorse Spillway Stoplog Refurbishment	-	-	-	1,000.0	1,000.0
Lewes River Boat Lock Road Access Rebuild	-	-	-	1,200.0	1,200.0
Subtotal	**22,908.6**	**8,295.9**	**15,142.7**	**38,446.1**	**84,793.3**
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions					
Generation					
Faro Fuel System	-	990.8	-	-	990.8
Wareham Spillway Stoplogs - New Set	385.2	-	-	-	385.2
WH3 Tailrace Gate Certification	-	248.9	-	-	248.9
MBH1/2 Seal Water Filtration	-	-	285.7	-	285.7
WH4 Air Admission Valve Automation	-	-	-	200.0	200.0
WG2 Cylinder Heads Swap	-	-	-	500.0	500.0
WG1 Radiator Replacement	-	-	-	300.0	300.0
WH1&2 Penstock Repair	226.7	-	-	-	226.7
Wareham Spillway - Gate Refurbishment	482.8	-	-	-	482.8
Other Projects with <$100k Spending	311.8	306.9	255.7	75.0	949.4
Subtotal	**1,406.4**	**1,546.6**	**541.4**	**1,075.0**	**4,569.4**
Transmission					
Transmission Line Access	551.5	-	-	-	551.5
Alexco Mobile Substation Connection	193.4	-	-	-	193.4
Alexco Mobile Substation Connection Contributions	(193.2)	-	-	-	(193.2)
L177 Re Route	-	11.7	738.3	-	749.9
L177 Re Route Contributions	-	-	(433.6)	-	(433.6)
NWTEL Make Ready Work	-	-	175.0	-	175.0
P&C: S170 Protection, Control and SCADA Upgrade	-	-	-	839.0	839.0
L177 Gang Switches	-	-	-	250.0	250.0
Transmission Line Test and Treat Program 2020-22	-	-	-	250.0	250.0
Other Projects with <$100k Spending	25.9	132.4	104.4	145.0	407.7
Subtotal	**577.6**	**144.1**	**584.1**	**1,484.0**	**2,789.8**
Distribution					
Customer Extensions	942.9	200.9	1,727.1	600.0	3,470.8
Customer Extensions Customer Contributions	(846.1)	(123.0)	(1,260.7)	(400.0)	(2,629.7)
IPP Connections	-	-	5,205.3	-	5,205.3
IPP Connections Customer Contributions	-	-	(6,400.9)	-	(6,400.9)
Synchronous Condenser Overhaul	-	-	616.3	-	616.3
Dawson Distribution 3 Phase Loop	-	-	350.0	-	350.0
Other Projects with <$100k Spending	48.4	97.9	150.0	155.0	451.4
Subtotal	**145.3**	**175.8**	**387.0**	**355.0**	**1,063.1**
General Plant					
Major Crane Assessment/Refurbishment	292.8	-	-	700.0	992.8
Server Replacements	118.9	-	-	-	118.9
Vehicle Purchases	-	464.0	623.8	567.0	1,654.8
New Mobile Office Unit - IT	-	-	810.2	-	810.2
Aishihik Bridge Redecking	-	109.3	-	-	109.3
Compact Digger Truck	-	-	200.4	-	200.4
Skid Steer	-	-	189.0	-	189.0
Mayo-McQuesten Radio to Fiber Migration	-	-	134.6	-	134.6
Waste Management Equipment	-	-	110.0	-	110.0
HQ Datacenter Server Replacement	-	-	-	300.0	300.0
SCADA Operation Network Segregation	-	-	-	245.0	245.0
Other Projects with <$100k Spending	502.8	575.3	727.5	800.0	2,605.7
Subtotal	**914.5**	**1,148.6**	**2,795.6**	**2,612.0**	**7,470.8**
Overhaul					
AH1 10 Year Overhaul	-	-	2,461.0	-	2,461.0
AH2 Overhaul	-	2,340.9	-	-	2,340.9
WG1 Overhaul	-	-	400.0	-	400.0
WG2 Overhaul	-	-	400.0	-	400.0
WG3 Overhaul	-	-	-	400.0	400.0
DD4 Overhaul	-	-	-	450.0	450.0
Subtotal	**-**	**2,340.9**	**3,261.0**	**850.0**	**6,451.8**

Right of Use Assets					
Right of Use Asset Battery Land Lease	-	1,003.8	-	-	1,003.8
Right of Use Asset Kulan Land	-	177.1	-	-	177.1
Right of Use Asset 1 Lindeman Road	0	0	750.1	0	750.1
Subtotal	**-**	**1,180.9**	**750.1**	**-**	**1,931.0**
RFID					
RFID	1,393.3	7,815.5	899.9	681.7	10,790.4
RFID Contributions	-	(5,899.4)	-	-	(5,899.4)
Subtotal	**1,393.3**	**1,916.1**	**899.9**	**681.7**	**4,891.0**
RFSR					
Reserve for Site Restoration Bucket	-	-	763.1	-	763.1
Subtotal	**-**	**-**	**763.1**	**-**	**763.1**
Deferred Costs – Major projects > $1 million – Rate Base Additions					
DSM Program Development	10.4	1,430.8	-	-	1,441.2
DSM Program Development Contributions	-	(1,141.6)	(21.6)	-	(1,163.3)
DSM Program 2022-2030	-	64.2	1,271.6	1,160.0	2,495.9
Southern Lakes Storage	-	-	8,784.2	-	8,784.2
Aishihik 5-Year License Renewal	-	3,903.4	575.4	-	4,478.8
Subtotal	**10.4**	**4,256.8**	**10,609.5**	**1,160.0**	**16,036.7**
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions					
IPP Standing Offer Program Implementation	326.0	-	70.3	-	396.3
Dam Safety Review	254.5	-	-	-	254.5
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)	-	-	385.6	-	385.6
Mayo Civil Infrastructure Refurbishment Planning	-	-	168.4	-	168.4
System Wide Arc Flash Study	-	-	197.7	-	197.7
Whitehorse Post-Flood Assessment	-	115.2	-	-	115.2
WRGS Thermal Assessment & Permitting	-	-	-	413.0	413.0
Public Safety Plans	-	-	225.0	-	225.0
System Wide Stability Study	-	-	200.0	-	200.0
Digital Strategy and Policy Development	-	-	120.0	-	120.0
Privacy Management Program	-	-	100.0	-	100.0
Vegetation Management Plan Update	-	-	225.0	-	225.0
Cyber Security Framework	-	-	-	140.0	140.0
Transmission Line Detailed Inspection Program	-	-	-	250.0	250.0
Gates/TIV's Certification Assessment System Wide	-	-	-	200.0	200.0
Digital Reporting Review	-	-	-	125.0	125.0
Records Policy Planning and Program Development	-	-	-	100.0	100.0
Breaker Condition Assessment	-	-	-	100.0	100.0
Other Projects with <$100k Spending	262.8	172.6	342.2	(10.0)	767.6
Subtotal	**843.3**	**287.9**	**2,034.2**	**1,318.0**	**4,483.3**
Intangible Assets – Major projects > $1 million - Rate Base Additions					
PAMMS Asset Management Framework	-	-	5,466.2	-	5,466.2
EAM Purchase and Implementation	4,549.9	-	-	-	4,549.9
Subtotal	**4,549.9**	**-**	**5,466.2**	**-**	**10,016.0**
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions					
EAM Enhancements Review	-	147.3	-	-	147.3
Network Software Traffic Shaping	-	-	250.0	-	250.0
CIS Replacement	-	-	118.3	-	118.3
P&C Central Event Data Collection System	-	-	-	150.0	150.0
SharePoint Upgrades	-	-	-	100.0	100.0
Other Projects with <$100k Spending	98.8	131.0	72.8	130.0	432.6
Subtotal	**98.8**	**278.3**	**441.1**	**380.0**	**1,198.2**
Total added to rate base	**32,848.0**	**21,571.8**	**42,913.0**	**48,361.8**	**145,694.6**
Major Projects (Capital, Deferred, Intangible net contrib)	27,468.9	12,552.7	31,218.4	39,606.1	110,846.1
Projects $100,000 to $1 million	2,735.44	2,165.08	5,130.92	5,929.01	15,960.44
Right of Use Assets	-	1,180.86	750.13	-	1,930.99
Overhauls	-	2,340.9	3,261.0	850.0	6,451.8
RFID	1,393.3	1,916.1	899.9	681.7	4,891.0
RFSR	-	-	763.1	-	763.1
Other Projects with <$100k Spending	1,250.4	1,416.3	1,652.6	1,295.0	5,614.2
Total added to rate base	**32,848.0**	**21,571.8**	**43,676.0**	**48,361.8**	**146,457.7**

YUKON ENERGY CORPORATION 2023/24 GRA — **Table 5.7**
WORK IN PROGRESS CONTINUITY SCHEDULE - Projects Not impacting Rate Base — **August 2023**
($000S)

	2021				2022			
	WIP Opening Balance	Expenditures	Adjustments	WIP Closing Balance	WIP Opening Balance	Expenditures	Adjustments	WIP Closing Balance
Capital Projects – Major projects > $1 million – Not impacting Rate Base								
Energy Storage System	517.4	854.5	-219.5	1,152.4	1,152.4	8,848.3	0.0	10,000.7
Energy Storage System Contributions	-316.2	-581.3	0.0	-897.5	-897.5	-6,128.6	0.0	-7,026.1
MH0 rockslide Stabilization and Remediation								
MH0 Surge Chamber Replacement					0.0	324.5	0.0	324.5
Lewes River Boat Lock					0.0	64.3	0.0	64.3
Lewes River Boat Lock Contributions								
Mayo Civil/Structural Infrastructure Program								
Aishihik Roof Replacement								
Whitehorse WH0 P125 Trash Rake								
Whitehorse WH4 Trash Rake								
P126 Building Renovation								
P&C: WH4 Protection, Control, SCADA and Installation								
P&C: S150 Protection, Control and SCADA Upgrade								
Pumped Storage	0.4	0.0	0.0	0.4	0.4	72.1	0.0	72.5
AH1 and AH2 Governor Upgrades								
Lewes Gate Automation								
Faro 870S and S140 Substation Interconnection								
Mayo Lake Control Structure Valve Clean Out System								
WH3 Headgate Replacement								
Subtotal	**201.6**	**273.2**	**-219.5**	**255.3**	**255.3**	**3,180.6**	**0.0**	**3,435.9**
Capital Projects – Projects $100,000 to $1 million – Not impacting Rate Base								
Lewes Gate/Seal Refurbishment					0.0	149.2	0.0	149.2
MBH1/MBH2 LP/HP Oil Supply System replacement								
Carmacks Substation Relocate								
Central Storeroom for Generation Parts								
P&C: DD0 Exciter, Governor and Load Sharing								
Other Projects with <$100k Spending by 2024	486.7	-479.3	0.0	7.4	7.4	0.0	0.0	7.4
Subtotal	**486.7**	**-479.3**	**0.0**	**7.4**	**7.4**	**149.2**	**0.0**	**156.7**
Deferred Costs – Major projects >$1 million – Not impacting Rate Base								
Whitehorse Water Use License Renewal	0.0	122.0	0.0	122.0	122.0	1,998.0	0.0	2,120.0
MGS Water Use License Renewal					0.0	94.2	0.0	94.2
Aishihik 25-Year License Renewal					0.0	5,734.9	0.0	5,734.9
Mayo Lake Storage (see also P11-073)	4,060.5	342.5	0.0	4,403.0	4,403.0	138.4	0.0	4,541.4
Atlin Hydro SIS and EPA	201.7	784.9	0.0	986.6	986.6	487.6	0.0	1,474.2
Atlin Hydro SIS and EPA Contributions	0.0	-63.5	0.0	-63.5	-63.5	-225.0	0.0	-288.5
2024 Resource Plan								
Subtotal	**4,262.3**	**1,185.8**	**0.0**	**5,448.1**	**5,448.1**	**8,228.1**	**0.0**	**13,676.2**
Deferred Costs – Projects $100,000 to $1 million – Not impacting Rate Base								
Renewable Diesel Pilot Project								
Substation and Distribution Load Planning Study								
Skagway Shoreside Power								
GRA 2023-2024 (Hearing Reserve Acct)								
Other Projects with <$100k Spending by 2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Intangible Assets – Major projects > $1 million – Not impacting Rate Base								
ERP Replacement	0.0	25.0	0.0	25.0	25.0	74.8	0.0	99.8
Subtotal	**0.0**	**25.0**	**0.0**	**25.0**	**25.0**	**74.8**	**0.0**	**99.8**
Intangible Assets – Projects $100,000 to $1 million – Not impacting Rate Base								
Project Management Software	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Projects with <$100k Spending by 2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Total	**4,950.6**	**1,004.8**	**-219.5**	**5,735.8**	**5,735.8**	**11,632.8**	**0.0**	**17,368.6**
Total Major Projects [before contributions]	517.8	854.6	-219.5	1,152.9	1,152.9	9,309.2	0.0	10,462.1
Maintenance Capital [before contributions]								
Total Generation	486.7	-479.3	0.0	7.4	7.4	149.2	0.0	156.7
Total Transmission	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Distribution	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total General Plant & Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital Contributions	-316.2	-581.3	0.0	-897.5	-897.5	-6,128.6	0.0	-7,026.1
Deferred Costs [before contributions]	4,262.3	1,249.3	0.0	5,511.6	5,511.6	8,453.1	0.0	13,964.7
Deferred Cost Contributions	0.0	-63.5	0.0	-63.5	-63.5	-225.0	0.0	-288.5
Intangible Assets	0.0	25.0	0.0	25.0	25.0	74.8	0.0	99.8
Total	**4,950.6**	**1,004.8**	**-219.5**	**5,735.8**	**5,735.8**	**11,632.8**	**0.0**	**17,368.6**

YUKON ENERGY CORPORATION 2023/24 GRA — **Table 5.7**
WORK IN PROGRESS CONTINUITY SCHEDULE - Projects Not impacting Rate Base — **August 2023**
($000S)

	2023				2024			
	WIP Opening Balance	Expenditures	Adjustments	WIP Closing Balance	WIP Opening Balance	Expenditures	Adjustments	WIP Closing Balance
Capital Projects – Major projects > $1 million – Not impacting Rate Base								
Energy Storage System	10,000.7	19,950.0	0.0	29,950.7	29,950.7	1,000.0	0.0	30,950.7
Energy Storage System Contributions	-7,026.1	-9,473.9	0.0	-16,500.0	-16,500.0	0.0	0.0	-16,500.0
MH0 rockslide Stabilization and Remediation	0.0	2,500.0	0.0	2,500.0	2,500.0	9,500.0	0.0	12,000.0
MH0 Surge Chamber Replacement	324.5	1,000.0	0.0	1,324.5	1,324.5	3,000.0	0.0	4,324.5
Lewes River Boat Lock	64.3	450.0	0.0	514.3	514.3	15,000.0	0.0	15,514.3
Lewes River Boat Lock Contributions					0.0	-4,500.0	0.0	-4,500.0
Mayo Civil/Structural Infrastructure Program	0.0	200.0	0.0	200.0	200.0	2,000.0	0.0	2,200.0
Aishihik Roof Replacement					0.0	200.0	0.0	200.0
Whitehorse WH0 P125 Trash Rake					0.0	200.0	0.0	200.0
Whitehorse WH4 Trash Rake					0.0	200.0	0.0	200.0
P126 Building Renovation					0.0	500.0	0.0	500.0
P&C: WH4 Protection, Control, SCADA and Installation					0.0	690.0	0.0	690.0
P&C: S150 Protection, Control and SCADA Upgrade					0.0	600.0	0.0	600.0
Pumped Storage	72.5	2.0	0.0	74.5	74.5	250.0	0.0	324.5
AH1 and AH2 Governor Upgrades					0.0	200.0	0.0	200.0
Lewes Gate Automation					0.0	250.0	0.0	250.0
Faro 870S and S140 Substation Interconnection					0.0	400.0	0.0	400.0
Mayo Lake Control Structure Valve Clean Out System					0.0	50.0	0.0	50.0
WH3 Headgate Replacement					0.0	750.0	0.0	750.0
Subtotal	**3,435.9**	**14,628.1**	**0.0**	**18,064.1**	**18,064.1**	**30,290.0**	**0.0**	**48,354.1**
Capital Projects – Projects $100,000 to $1 million – Not impacting Rate Base								
Lewes Gate/Seal Refurbishment	149.2	0.0	0.0	149.2	149.2	200.0	0.0	349.2
MBH1/MBH2 LP/HP Oil Supply System replacement					0.0	150.0	0.0	150.0
Carmacks Substation Relocate					0.0	250.0	0.0	250.0
Central Storeroom for Generation Parts					0.0	400.0	0.0	400.0
P&C: DD0 Exciter, Governor and Load Sharing					0.0	100.0	0.0	100.0
Other Projects with <$100k Spending by 2024	7.4	60.0	0.0	67.4	67.4	135.0	0.0	202.4
Subtotal	**156.7**	**60.0**	**0.0**	**216.7**	**216.7**	**1,235.0**	**0.0**	**1,451.7**
Deferred Costs – Major projects >$1 million – Not impacting Rate Base								
Whitehorse Water Use License Renewal	2,120.0	5,817.9	0.0	7,937.8	7,937.8	2,500.0	0.0	10,437.8
MGS Water Use License Renewal	94.2	3,500.0	0.0	3,594.2	3,594.2	3,100.0	0.0	6,694.2
Aishihik 25-Year License Renewal	5,734.9	1,025.0	0.0	6,759.9	6,759.9	400.0	0.0	7,159.9
Mayo Lake Storage (see also P11-073)	4,541.4	110.0	0.0	4,651.4	4,651.4	110.0	0.0	4,761.4
Atlin Hydro SIS and EPA	1,474.2	150.0	0.0	1,624.2	1,624.2	0.0	0.0	1,624.2
Atlin Hydro SIS and EPA Contributions	-288.5	0.0	0.0	-288.5	-288.5	0.0	0.0	-288.5
2024 Resource Plan	0.0	400.0	0.0	400.0	400.0	1,600.0	0.0	2,000.0
Subtotal	**13,676.2**	**11,002.9**	**0.0**	**24,679.0**	**24,679.0**	**7,710.0**	**0.0**	**32,389.0**
Deferred Costs – Projects $100,000 to $1 million – Not impacting Rate Base								
Renewable Diesel Pilot Project	0.0	25.0	0.0	25.0	25.0	200.0	0.0	225.0
Substation and Distribution Load Planning Study	0.0	0.0	0.0	0.0	0.0	300.0	0.0	300.0
Skagway Shoreside Power	0.0	100.0	0.0	100.0	100.0	50.0	0.0	150.0
GRA 2023-2024 (Hearing Reserve Acct)	0.0	250.0	0.0	250.0	250.0	0.0	0.0	250.0
Other Projects with <$100k Spending by 2024	0.0	25.0	0.0	25.0	25.0	85.0	0.0	110.0
Subtotal	**0.0**	**400.0**	**0.0**	**400.0**	**400.0**	**635.0**	**0.0**	**1,035.0**
Intangible Assets – Major projects > $1 million – Not impacting Rate Base								
ERP Replacement	99.8	75.0	0.0	174.8	174.8	4,200.0	0.0	4,374.8
Subtotal	**99.8**	**75.0**	**0.0**	**174.8**	**174.8**	**4,200.0**	**0.0**	**4,374.8**
Intangible Assets – Projects $100,000 to $1 million – Not impacting Rate Base								
Project Management Software	0.0	0.0	0.0	0.0	0.0	150.0	0.0	150.0
Other Projects with <$100k Spending by 2024	0.0	0.0	0.0	0.0	0.0	100.0	0.0	100.0
Subtotal	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**250.0**	**0.0**	**250.0**
Total	**17,368.6**	**26,166.0**	**0.0**	**43,534.6**	**43,534.6**	**44,320.0**	**0.0**	**87,854.6**
Total Major Projects [before contributions]	10,462.1	24,102.0	0.0	34,564.1	34,564.1	34,790.0	0.0	69,354.1
Maintenance Capital [before contributions]								
Total Generation	156.7	60.0	0.0	216.7	216.7	485.0	0.0	701.7
Total Transmission	0.0	0.0	0.0	0.0	0.0	100.0	0.0	100.0
Total Distribution	0.0	0.0	0.0	0.0	0.0	250.0	0.0	250.0
Total General Plant & Equipment	0.0	0.0	0.0	0.0	0.0	400.0	0.0	400.0
Capital Contributions	-7,026.1	-9,473.9	0.0	-16,500.0	-16,500.0	-4,500.0	0.0	-21,000.0
Deferred Costs [before contributions]	13,964.7	11,402.9	0.0	25,367.6	25,367.6	8,345.0	0.0	33,712.6
Deferred Cost Contributions	-288.5	0.0	0.0	-288.5	-288.5	0.0	0.0	-288.5
Intangible Assets	99.8	75.0	0.0	174.8	174.8	4,450.0	0.0	4,624.8
Total	**17,368.6**	**26,166.0**	**0.0**	**43,534.6**	**43,534.6**	**44,320.0**	**0.0**	**87,854.6**

APPENDIX 5.1A
CAPITAL PROJECTS >$1 MILLION
ADDED TO RATE BASE

APPENDIX 5.1A: CAPITAL PROJECTS >$1 MILLION ADDED TO RATE BASE

Test year spending on major capital works projects focuses 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 on new supply options and expenditures to ensure sufficient dependable capacity for the integrated grid.

Total forecast to be added to year-end net rate base, net of contributions, but before depreciation impacts, for major capital works projects by the end of 2024 is approximately $71.953 million, including rate base adjustments to projects reviewed and approved in the 2021 GRA. Each major project added to rate base is reviewed separately below (see also Tables 5.1 and 5.6 at the end of Tab 5):

- **Spending to address Capacity Planning Requirements** – Net rate base impact of approximately $33.825 million:
  - **Thermal Replacement (16.5 MW)** – Forecast cost of approximately $18.176 million for 5 MW diesel replacement forecast to be completed and in service at Faro in 2024, and cost of $0.15 million in 2021 for completed Whitehorse feasibility study.
  - **2023 Mayo-Faro Diesel Infrastructure** – Forecast cost of $4.300 million in 2023; and forecast to be completed and in service in 2023.
  - **Whitehorse Interconnection** – Forecast cost of approximately $11.199 million; and forecast to be completed and in service in 2024.
- **Spending on Sustaining Capital -** Net rate base impact of approximately $30.262 million:
  - **Transmission Line Replacement L178** – Actual cost of approximately $5.084 million for facilities in service to the end of 2022, with forecast cost of $1.000 million in 2023 and $5.000 million in 2024 for facilities forecast to be completed and in service in 2023 and 2024 (total forecast cost of $11.084 million added to rate base by end of 2024).
  - **WH1 Head Gate Replacement -** Actual cost of approximately $2.204 million for facilities in service in 2022
  - **P&C: S250 Callison Protection, Control and SCADA Upgrade** – Forecast cost of approximately $2.125 million in 2023; and forecast to be completed and in service in 2023.

- **MH0 Road and Road Slope Stability** – Forecast cost of approximately $1.874 million in 2023 with work forecast to be completed and project in service 2023.

- **Wareham Spillway Concrete Repair -** Actual cost of approximately $0.898 million and $0.447 million for facilities in service to the end of 2021 and 2022 respectively, with forecast cost of $0.5 million in 2023 for facilities forecast to be completed and in service in 2023 (total forecast cost of $1.845 million added to rate base by end of 2023).

- **Whitehorse Stoplog Crane Replacement** – Forecast cost of approximately $4.247 million, for work forecast to be completed in 2023.

- **Schwatka Lake Safety/ Debris Boom -** Forecast cost of approximately $1.097 million, for work forecast to be completed in 2023.

- **Dawson Voltage Conversion** – Forecast cost of approximately $1.872 million in 2024; forecast to be completed and in service in 2024.

- **Whitehorse Spillway Stoplog Refurbishment -** Forecast cost of approximately $1.000 million, for work forecast to be completed in 2024.

- **Lewes River Boat Lock Road Access Rebuild -** Forecast cost of approximately $1.200 million, for work forecast to be completed in 2024.

- **Changes for Projects Reviewed & Approved in 2021 GRA** – Two capital projects reviewed and approved in Appendix A to Board Order 2022-03 have adjusted rate base for the 2023/24 GRA – total adjustment of $2.728 million added to the rate base previously approved in 2021 GRA:

  - **Mayo-McQuesten Transmission Line Upgrade** – Actual cost of $28.939 million in 2021 offset by contributions of $21.064 million; and actual cost of $0.898 million in 2022, offset by contributions of $0.651 million; the project was completed and in service in 2022 with total actual cost of $29.836, offset by total contributions of $21.715 million (net cost of $8.121 million). Net cost of $8.628 that was added to rate base during the 2021 GRA[1] is reduced by $0.507 million based on final costs and contributions.

[1] Board Order 2022-03, Appendix A, para 258.

  - **Replace P125 WH2 Head Gate** – The Board in the 2021 GRA directed that costs for this project will only be added to approved rate base in the next GRA, based on the actual spending amount incurred. In addition to the actual cost of $2.072 million that the Board previously found reasonable[2], actual additional costs of approximately $0.149 million have been incurred for facilities in service to the end of 2021, i.e., total project costs to be added to approved rate base for the 2023/24 GRA equal $2.221 million**.**

- **Capital investments on New Supply options to maximize renewable energy generation** – Net rate base impact of approximately $7.867 million addition to 2021 approved rate base:

  - **WH2 Uprate Construction and Engineering** – Actual cost for construction and engineering in 2021 of $12.358 million; and actual construction cost of $0.457 million in 2022. Total in service cost of $12.814 million, of which $5.736 million was approved cost added to rate base following the 2021 GRA[3] – addition of $7.078 million to 2021 rate base is now sought.

  - **WH4 Servomotor Replacement** – Actual cost of $1.318 million in 2021 and $0.019 million in 2022. Total in service cost of $1.337 million at the end of 2022, of which $0.548 million was approved cost added to rate base following the 2021 GRA[4] – addition of $0.789 million to 2021 rate base is now sought.

Excluding the two projects already reviewed and approved in the 2021 GRA (Mayo-McQuesten Transmission Line Upgrade, and Replace P125 WH2 Head Gate), business case summaries for each of the above major capital projects added to rate base in this GRA are reviewed in the sections that follow.

[2] Board Order 2022-03, Appendix A, para 270.
[3] Board Order 2022-03, Appendix A, para 278.
[4] Board Order 2022-03, Appendix A, para 282.

SECTION 5.1A-1: THERMAL REPLACEMENT PROJECT (16.5 MW) (RATE BASE ADDITIONS OF $0.15 MILLION IN 2021, $18.176 MILLION IN 2024)

The replacement of 12.5 MW of retiring diesel units in Whitehorse, Faro and Dawson is a key project in Yukon Energy's 10-Year Renewable Electricity Plan; an additional 4 MW diesel expansion is also now planned at Dawson, yielding the overall project's planned diesel installation of 16.5 MW.[5] The dependable capacity from this thermal replacement project (Project) helps to address the existing and forecast Yukon Integrated System (YIS) dependable capacity shortfall under the N-1 planning criterion,[6] and also retains dependable capacity as needed for retail customers in Dawson.

The Thermal Replacement project will install and commission in 2024 two 2.5 MW US Environmental Protection Agency (EPA) Tier 4 modular diesel units at the Faro diesel plant to replace 2023 retirement of Faro Diesel 1 (FD1) (5.1 MW); this new 5 MW of thermal dependable capacity will displace the need to rent three additional 1.8 MW diesel units for winter 2024/25, and add approximately $18.2 million to YEC's 2024 year end ratebase.

The Thermal Replacement project is also proceeding with the following components at Whitehorse and Dawson at a forecast cost of approximately $42.4 million to provide further displacement of diesel rental requirements for winter 2025/26 (these project component costs are forecast to remain in WIP at the end of 2024 and therefore do not affect 2023/24 GRA revenue requirements):

- Installation of 5 MWs (two 2.5 MW EPA Tier 4 modular units) at the Whitehorse Rapids Generating Station (WRGS) that will replace the previously retired Whitehorse Diesel 3 (WD3) (5.15 MW) – a feasibility study completed in 2021, adding $0.15 million to rate base in that year (but not approved in the 2021 GRA, and therefore a rate base addition for the 2023 GRA), determined that modular units were a more cost effective and less risky option than installing the diesel replacement units in the existing P126 diesel plant[7]; and

- Installation of 6.5 MWs (two 3.25 MW EPA Tier 4 modular units) at the S250 Callison Substation near Dawson City to replace planned retirement in 2024 of Dawson Diesel units DD2 and DD5 (total 2.5 MWs) and also to address concerns raised regarding the anticipated load growth in Dawson and the inability of currently installed thermal capacity to supply the town in the event of

[5] The initial Thermal Replacement project as described in Yukon Energy's 10-Year Renewable Electricity Plan only provided for 2.5 MW of diesel replacement at Dawson City. The expansion to provide 6.5 MW of diesel capacity at Dawson was assessed and approved by YEC's Board in 2023 in response to the concerns noted regarding anticipated load growth in Dawson.
[6] See Section 2.4 of this 2023/24 GRA.
[7] After including the $0.15 million in 2023 rate base, approximately $42.2 million of forecast costs remain for the Whitehorse and Dawson diesel replacement/ enhancement components of the Project.

a transmission line failure. This expanded thermal capacity will address the significant safety risks and the potential for damage to municipal and residential infrastructure as Dawson is in an islanded scenario during the winter season, multiple times annually.

Justification and Alternatives

The 5 MW of new dependable thermal capacity being provided in 2024 at the Faro diesel plant helps to address the existing and forecast YIS dependable capacity shortfall under the N-1 planning criterion. Section 2.4 of this Application describes the N-1 planning criterion and the 36 MW of diesel rental capacity needed in 2023 and 2024 (excluding spares) to address the YIS dependable capacity shortfall estimated under this criterion with existing and planned non-rental YIS generation. Without the 5 MW of diesel replacement at Faro, the 2024 YIS dependable capacity shortfall for winter 2024/25 would be increased by 5 MW and three additional 1.8 MW diesel rental units would be required.

- The N-1 dependable capacity need for this 5 MW of Faro diesel replacement on the YIS is forecast to continue over the project's expected 40-year economic life.[8]

- The benefits of this 5 MW of new permanent thermal capacity over equivalent rented diesel capacity (as well as relative to the replaced end-of-life diesel units) include enhanced reliability, enhanced efficiency, reduced air emissions and reduced noise.

In addition to assessing added thermal requirements at Dawson City as reviewed above, YEC examined the following non-rental alternatives to provide the planned thermal replacements at Faro, Whitehorse and Dawson City:

- **Diesel engine selection** – The YIS is considered islanded and remote, and therefore EPA Tier 2 diesel engines could be selected rather than EPA Tier 4 diesel engines under the exemption applicable to islanded communities not connected to the North American grid. However, after review, the EPA Tier 4 diesel engine was selected for all three locations to provide reduced particulate and nitrous oxide / sulfur oxide (NOx/Sox) emissions that will reduce air emissions and provide positive environmental benefits for the local communities. Selection of Tier 4 engines will assist with the renewal of the air emissions permit for maximum applied for diesel capacity at both WGRS and Faro – as part of the permitting of 15.5 MW of thermal generation at the Faro

[8] Section 4.1.1 of YEC's Atlin EPA Submission filed with the YUB in April 2022 during the Board's review of the Atlin EPA showed that the forecast non-industrial peak winter load requirement relevant to the N-1 planning criteria determinations continues to grow during the next 20 years regardless of actual mine loads. The 5 MW of new Faro diesel replacement continues to be needed even with the addition of other planned thermal replacement, the BESS project, Atlin EPA, planned DSM, and the potential Moon Lake Pump Storage Phase One and Phase Two.

site, Yukon Government raised concerns about the NOx emissions under worst-case meteorological conditions, and installing EPA Tier 4 diesel engines in Faro will alleviate some of these concerns.

- **EPC contractor selection -** YEC completed a public procurement process prior to mid 2022 for an Engineering, Procurement and Construction (EPC) contractor for all three project locations to complete the supply and installation of new diesel generator units at all three project locations. Only one compliant bid was received from Wildstone Construction Ltd. in a partnership with Finning Canada and Caterpillar ('Wildstone/Finning'). Price options were requested for both EPA Tier 2 and Tier 4 rated diesel engines and an optional natural gas engine option for Whitehorse. Based on the outcome of this procurement process, YEC entered into a fixed price contract with Wildstone / Finning to complete the thermal replacements at the three locations with Tier 4 rate diesel engines where diesel thermal is selected.

- **Selection of Modular unit option at WRGS** - Assessment work completed in 2021 concluded that significant upgrades would be required to mitigate the risk of soil liquefaction during a seismic event and to bring the WRGS P126 building into compliance with the 2015 National Building Code of Canada (NBCC). The costs of these upgrades were estimated at $5,000,000, which would materially impact the economics of the thermal replacement at the Whitehorse facility. Therefore, in November 2021, the YEC Board approved the removal of the P126 renovation from the scope of the project at the Whitehorse location, and instead approved a plan to procure and install a containerized or 'packaged' modular thermal plant at the WRGS facility.

- **Select diesel vs natural gas thermal option at WRGS –** Thermal options for 5 MW with Natural Gas (C175-16, 1800 rpm engine) and with Diesel (EPA Tier 4 engine) were compared. The Natural Gas option provides material environmental benefits in terms of reduced greenhouse gas emissions and lower emissions of local air contaminants (particulates, Nitrous Oxide and Sulphur Oxides), when compared to the EPA Tier 4 diesel option. The Natural Gas option also offers lower fuel and maintenance costs. However, the capital costs of the Natural Gas option were ~ $3.0 million higher with 5 MW permanent capacity, and ~$4.4 million higher with added ability to rent a further 5 MW Natural Gas unit, than the price of an EPA Tier 4 diesel engine solution, reflecting slightly higher engine costs (~$0.5 million) and additional costs for LNG gas vaporization and gas handling system costs (ranging from $2.9 to $4.4 million for the referenced options).[9] Added supply chain risks were also noted for the Natural Gas option unless an offsite system storage is established in the Whitehorse area.

- YEC's assessment concluded that it will not be possible to justify the additional capital costs of the Natural Gas option based on the expected utilization of the Whitehorse thermal replacement plant, and therefore the Diesel EPA Tier 4 option was selected. Key factors in this assessment for the current 5 MW thermal replacement project included the following:
    - The new 5 MW thermal plant will be lower in the generation 'stacking order' than the existing 13.2 MW LNG plant, the rental diesel engines operated for their included 'free' operating hours and other renewable generation currently scheduled to come online in the coming years such as the Atlin Hydro Expansion project.
    - Therefore, the expected utilization of the Whitehorse thermal replacement plant is expected to be relatively low (~1,000 hours/year) since the plant will likely be used for peaking and emergency backup uses only.
    - Based on the calculated fuel savings of ~$400,000/annum at this level of annual utilization, the simple payback period on an additional $4.4 million investment in a Natural Gas plant would be ~11 years with the 5 MW permanent Natural Gas option with added 5 MW gas rental capability), and ~7.5 years with the only the 5 MW permanent Natural Gas option.

Faro Project Scope

The overall project scope for diesel installation at each site includes the following:

- Relevant assessment and regulatory permitting (YESAA, Air Emissions and Fuel Storage Tank permit and amendments);
- All site investigation and assessments required as pre-requisite to performing the detailed design work, including as a minimum:
    - Ground system condition;

[9] Feasibility assessments indicated that a new vaporizer is required for all Natural Gas options to provide redundancy in the LNG vaporization process and to avoid a single point of failure, and the existing odorant system currently in P126 diesel plant must also be replaced with a bigger odorant system at the LNG the plant. Otherwise, the existing gas handling capacity and glycol system at the Whitehorse LNG plant, and the 4-inch gas pipeline handling capacity connecting the LNG plant with P126 are also sufficient for the above referenced Natural Gas options.

  - Geotechnical investigations;
  - Condition assessment of the existing equipment related to the power upgrade and integration work.

- Engineering studies:
  - Grounding system studies if deemed required as a result of the review of the existing documentation;
  - Load flow study for each site;
  - Short circuit study for each site;
  - Arc flash study for each site.

- Design, manufacturing, delivery, installation, testing and commissioning of two (2) new modular diesel or natural gas generator units for the Whitehorse plant corresponding to 5 MW generation capacity total;

- Design, manufacturing, delivery, installation, testing and commissioning of all structural, architectural components, gensets, fuel storage, all first fill lubricants, fluids and hydraulic oil, balance of plant piping, cabling, controls, instrumentation, ancillary equipment and any other items not specifically referred to but essential for the safe, reliable and satisfactory installation, testing, commissioning, operation and maintenance of the aforementioned equipment;

- Integration of all the electrical and control systems to the existing facilities and infrastructure;

- All labour, materials, consumables, hardware, equipment, temporary utilities (water, power, sewer, garbage removal) and services for the planning, design, fabrication, QA/QC, supply, delivery, off-loading and storage at site, construction, testing and commissioning of the power plants;

- Offload and storage for all items as required including weather protection adaptable for all seasons and appropriate site conditions at the sites in Yukon;

- Mobilization of all aspects of the Contractor's workforce to site to complete the installation and construction Work, including but not limited to, accommodations, site offices, vehicles, meals, travel and training; and

- Supply of critical spares and special tools required for trouble free operation and maintenance of the equipment.

Specific scope for the Faro project includes the following:

- Installation of two (2) complete diesel generator sets, Local Engine Control Panel (LECP) and auxiliary systems (radiator, stack and silencer kit), switchgear, fuel storage tanks;

- Tie-in of the existing underground fuel header at the appropriate indicated points;

- Design and construction of a permanent foundation and containment for transformer S140-T1;

- Design, supply, fabrication, and installation of two (2) new skid mounted diesel fuel tanks inside the existing containment, including any foundations or anchors required for installation;

- Addressing deficiencies identified on the Faro temporary diesel substation commissioning report (S140-T1 transformer deficiency);

- New fencing around S140 substation with one vehicle access gate and two main-gates; and

- Installation of additional noise mitigation equipment deemed necessary after completion of the desktop noise study.

Faro Assessment and Permitting

The YESAA assessment of the Faro project location was completed in early Q2 2022 and the Air Emissions permit to operate beyond 10.6 MW was issued to YEC. The Air Emissions permit limits normal operations to a certain capacity without limiting actual installed capacity or capacity operation during an N-1 event to protect public health and safety[10].

[10] Under Section 49 of the *Yukon Environmental and Socio-economic Assessment Act*, YEC has the ability to operate any available diesel generating capacity in an N-1 event to protect public health and safety. The Board found in Appendix A to Order 2022-03 (para 110) "…that N-1 emergency conditions described by YEC appear on their face to be consistent with Subsection 49(1) of the Yukon Environmental and Socio-economic Assessment Act and with responding to an emergency that is in interest of public welfare, health or safety."

Faro is currently authorized to operate diesel-fired electrical generators up to a maximum capacity of 15.5 MW. This authorization was granted as a result of a recent YESAA assessment and associated decision document (YESAA Project Assessment 2021-0115). Pursuant to Part 2, Item 5 of the FGS Air Emissions Permit (No. 60-010-01) approval for the installation of the new generators contemplated by this project will require regulatory approval, but will not require a new YESAA assessment, as the permitting can be completed under the existing decision document for the facility. Because the units being proposed to replace existing generation at the site meeting modern emissions standards (EPA Tier 2 or higher) the regulatory approval should be fairly routine and achievable within 60 days of submitting an amendment application to the regulator. An amendment to the fuel storage tank permit for the facility will be required, but a decision document already exists for this activity at site as a result of the aforementioned YESAA assessment, so only regulatory approval will be required and should take about 30 days.

Permanent diesel dependable capacity at Faro will equal 8 MW for winter 2024/25 with the project's added 5 MW. Planned rental of 7 diesel units (12.6 MW) will enable the full 15.5 MW of Faro diesel facility authorized normal operations capacity and provide a further 5.1 MW of dependable capacity operation during an N-1 event to protect public health and safety.

The Town of Faro in early 2022 raised concerns about the noise from the diesels. Yukon does not have a noise regulation applicable to the Faro diesel facility; however, in response to the concerns raised, YEC retained SLR Consulting (Canada) Ltd. to conduct a noise survey to quantify both ambient and operational sound levels at different locations in the Town of Faro – and the noise survey assessments referenced the British Columbia Oil and Gas Commission (BCOGC) BC Noise Control Best Practices Guidelines (the Guidelines) which is commonly used in Yukon. The results of the noise survey indicated that the operational sound levels at various locations exceeded the nighttime permissible sound levels during operation of Faro diesel units. While the new diesel generators will have lower noise emissions than both the rentals and FD1, noise mitigation is included as part of the design and installation of the Faro diesel replacement project.

Project Schedule and Budget

As noted earlier, Wildstone Construction Ltd. was selected through a competitive tender process as the Generator EPC contractor for the replacement projects at all three locations. The Wildstone team is working closely with YEC's project team and the Owner's Engineer to design, procure, fabricate, pre-assemble the modular units, factory test, ship to site, construct the power plants and all accessories, complete final-assembly of the modular units on site, and commission the power plants in Whitehorse, Faro and Dawson. From the outset the first commissioning was scheduled at Faro in late 2023, followed by Dawson in early 2024 and Whitehorse in mid-2024. Updated commissioning is currently schedule in July 2024 at Faro, late November 2024 at Dawson and April 2025 at Whitehorse.

The Faro Thermal Replacement project budget for assets included in the 2024 GRA forecast rate base is outlined below in Table 5.1A-1.1, based on the EPC Contractor specific budget for Faro plus 30.3% (i.e., the 5 MW Faro share of the overall 16.5 MW Thermal Replacement Project diesel installations) of all other YEC Thermal Replacement Project non-EPC Contractor budget costs.[11]

Table 5.1A-1.1 – Faro Thermal Replacement Project Forecast Capital Costs

Item Description	Amount
EPC Contractor – Faro	15,180,000
Faro share of Thermal Replacement Project non-EPC Contractor costs for Faro, Whitehorse and Dawson estimated at approximately 30.3% of $9.885 million (includes Station Service Supply ($0.45 million), YEC internal cost ($1.185 million), Owner's Engineer (BBA at $0.655 million), Assessment and Permitting ($0.29 million), Engagement ($0.28 million), Fuel for on-site commissioning ($0.89 million), Contingency ($2.379 million), AFUDC ($1.71 million), feasibility and engineering ($0.162 million), initial planning costs ($1.884 million).	2,995,000
Total Budget	**18,175,000**
Capital Cost per MW	***$3,635,000***
LCOC ($/kw-yr)[12]	***$192.17***

The Levelized Cost of Capacity (LCOC) over a 40 year life for the 5 MW diesel replacement at Faro at $192.17 per kW-yr (2024$) is lower than the LCOC of $255 to $299 per kW-yr for 2024 rental diesel cost at Faro and $216 to $252 per kW-yr for all YEC 2024 diesel rental costs (assuming 40-years of rentals and excluding rental capital infrastructure costs).[13]

[11] The overall Project budget of $60.565 million includes $50.68 million of EPC Contractor costs (with $15.18 million for Faro, $14.195 million for Whitehorse, and $21.305 million for Dawson) and $9.885 million of other YEC Project forecast costs. The 2023 GRA rate base includes $0.150 million of these other costs for the feasibility study leading to selecting modular units for WRGS.

[12] LCOC assessed assuming $3,635 capital cost per kW, year 1 operating cost of $18.4 per kW with escalation at 2%/yr, 40 year project life and YEC WACC for new rate base of 6.018%/year per 2024 GRA (60% new debt financed at 4.23% and 40% equity financed at 8.70% per the current Application).

[13] LCOC assessed assuming $220.41 Faro site rental cost per kW in year 1 with escalation in range of 3% to 4%/yr, 40 year project life and YEC WACC for new rate base of 6.018%/year per 2024 GRA (60% new debt financed at 4.23% and 40% equity financed at 8.70% per the current Application). LCOC for all 2024 diesel rental costs is $216 to $252 per kW-yr assuming $186.02 average YEC rental cost per kW in year 1 with escalation in range of 3% to 4%/yr, 40 year project life and YEC WACC for new rate base of 6.018%/year per 2024 GRA; with a shorter 20 year rental life, the LCOC for all 2024 rental costs with these same assumptions is $202 to $220 per kW-yr; with infrastructure capital costs and 40-year life, LCOC for all 2024 rental costs is $227 to $264 per kw-yr.

The justification for the diesel replacement project includes securing long term reliability by replacing the need for rental diesel, and is therefore not dependent on securing cost savings relative to rental diesel. However, diesel rental costs savings are forecast to exceed Faro Project costs over the 40 year Project life, and diesel replacement is expected to be for higher cost units within the overall YEC diesel rentals at Faro, Whitehorse, and Mayo.

SECTION 5.1A-2: 2023 MAYO-FARO DIESEL INFRASTRUCTURE (RATE BASE ADDITION OF $4.3 MILLION IN 2023)

The 2023 Mayo-Faro Diesel Infrastructure Project (the Project) will provide infrastructure for mobile and modular diesel units at a new Mayo site further away from the community to assist in meeting the Yukon Integrated System (YIS) dependable capacity needs for the winter of 2023/24 (W2023) and beyond under the N-1 dependable capacity planning criteria. The Project will also provide diesel infrastructure modifications at the Faro site to accommodate new diesel installations at this site.

To provide sufficient dependable capacity for the YIS during the W2023, 20 rental diesel units (36 MW) are required to address the shortfall in required dependable capacity that the YIS permanent facilities can provide[14]. This is an increase of 5 required diesel rental units compared with the prior winter.

Existing rental diesel sites in Faro and Whitehorse have space for additional units, however current transformation capacity and air emission permitting are limiting the ability of those sites to house any additional rental units. Mayo is the remaining community served by YEC with existing diesel generation, and therefore Mayo has been selected as the location for the five added diesel rentals needed for 2023.

The current Mayo diesel facility is located within the townsite and has been under review for potential relocation to YEC's Mayo hydro site property in order to consolidate YEC Mayo generation facilities and to move diesel generation operation further from the townsite. The current diesel infrastructure development at Mayo for the 2023 diesel rentals will also provide for such potential future permanent diesel relocation at Mayo (although no specific plan has been finalized in this regard).

The substation located above the Mayo MH0 Plant (S249) has been selected as the new thermal site due to its available generation capacity, proximity to MH0 infrastructure, and accessibility for staff. This infrastructure has the potential to be used to connect additional permanent diesel generators in the future, either replacement of the units within the Mayo townsite or new thermal capacity. The cost estimate for the Mayo rental site infrastructure development is $3.44 Million and includes preliminary engineering, planning, design, materials, construction, and commissioning.

In addition to developing the third diesel rental site at Mayo, the Faro rental site will require significant modifications in 2023 to accommodate construction activities for the Thermal Replacement Project. This work is forecast to cost $0.86 million and includes moving rental units away from the new thermal plant site and purchasing new switchgear to install the rental units in the new locations.

[14] See Section 2.4 of Tab 2 of this GRA Application.

Forecast costs for the Project are based on the cost of a similar, recent rental infrastructure projects completed in Faro adjusted for inflation using consumer prices index from Statistics Canada to reflect the cost in 2023.

SECTION 5.1A-3: WHITEHORSE INTERCONNECTION PROJECT (RATE BASE ADDITION OF $11.199 MILLION IN 2024)

The development of the Whitehorse Battery Energy Storage System (BESS) and the planned addition of 5 MW of replacement thermal generation at the Whitehorse Rapids Generation Station (WRGS) site has triggered the need for a reconfiguration of the substations serving the WRGS and the expansion of the S171 Riverside substation (S171). Absent this reconfiguration, the BESS and new thermal and hydro generation (e.g., rental diesels, hydro uprates), in combination with other existing dependable capacity at Whitehorse would trigger a new N-1 scenario and would result in additional dependable capacity being required on the YEC system.

The Whitehorse Interconnection project (the Project) involves the modification and expansion of the S171 substation, including the purchase and installation of a new higher capacity transformer, and construction of transmission lines to connect the BESS project and the Whitehorse LNG to the S171 substation. The Project thereby avoids the BESS and new thermal generation creating a new N-1 contingency risk at S150 and thereby avoids the need for an investment in additional dependable capacity.

The scope of the Whitehorse Interconnection project includes the following:

Transmission line design and construction	• Connection of the BESS project from the WRGS fence-line to the S171 substation • Transfer of the grid connection for the Whitehorse LNG facility from the S150 substation to the S171 substation • Fibre installation to support SCADA and system protection
Riverside substation modifications	• Substation design and expansion • Breaker purchase and installation • Control Building expansion • Associated cabling, protection and control, civil works, and structure installation • Fiber Optic cable installation and termination
Transformer purchase and installation	• Specification development • Supply and installation

The approved Project budget is as follows:

Category	Amount ($000)
Owner's Engineer	450
Project Management	60
Permitting	25
Public Engagement	65
FN Engagement	15
YEC Internal Labor	500
Transformer	2,017
138 kV Breaker and CVT	200
EPC Contractor	6,947
AFUDC	300
Contingency	620
Total	**11,199**

A public tender RFP process was followed for the procurement of owner's engineer and project management services, transmission line and substation construction, and the transformer purchase and installation. Vallard Construction was selected as the EPC contractor and the transformer supplier was PTI Transformers.

SECTION 5.1A-4: TRANSMISSION LINE REPLACEMENT L178 (RATE BASE ADDITION OF $0.311 MILLION IN 2021, $4.772 MILLION IN 2022, $1.0 MILLION IN 2023, AND $5.0 MILLION IN 2024 – TOTAL RATE BASE ADDITIONS OF $11.084 MILLION)

Yukon Energy's 138 kV Whitehorse-Aishihik-Faro (WAF) transmission system was constructed in the late 1960's and early 1970's, and plays a critical role linking key hydro generation sources to load centres in Whitehorse and on the northern grid. Recent studies as well as a detailed line assessment in 2017 indicated that key components of the WAF system were at end of life, in poor condition, and required replacement.

This project is the final stage of the work to replace key components of the WAF system, with the following YEC transmission lines having been recently refurbished:

Line #	Route	Install Date
L170	Takhini Substation to Carmacks	1968
L171	Aishihik plant to Takhini Substation	1975
L172	Whitehorse plant to Takhini Substation	1968

Outages on the L178 transmission line currently trip at S164 (Takhini Substation) and can result in an outage on the Takhini-Carmacks L170 transmission line. Failure to complete this final element of the WAF refurbishment project would increase the risk of component failure on L178 resulting in a split in the North-South grid and significant thermal generation costs in the northern gird to maintain supply to all customers.[15] The importance of this line has also recently increased due to the additional thermal generation installed in Faro in response to overall YIS N-1 dependable capacity requirements. The alternative to continuing with this project is to respond to structure and component failures as they occur. This will lead to significant reliability impacts as well as higher overall costs. In addition, employee health and safety risk is reduced by planned maintenance activities that remove the likely need for emergency work.

A detailed line assessment completed in 2018 by Chimax Engineering established the scope of work for the multi-year refurbishment of L178. A portion of this work was completed between 2021 and 2022 while the remainder is planned for 2023-2027. The table below shows the number of structures completed and planned by repair type (see Table 5.1A-4.1).

[15] YUB-YEC-1-54(a) in 2021 GRA proceeding reviewed L178 outage by year from 2011 to 2020, and provided the following information on costs: total costs incurred from 2014-2020 due to outages (planned and unplanned) on L178 is $782,723, with average annual cost over the period is $86,969; additionally, capital investment in this line over the same period totaled $1,075,800.

Table 5.1A-4.1: Summary of Scope of Transmission Line Refurbishment Work (L178) – Number of Structures

Work Description	Assessment 2018	Completed Through 2022	Planned 2023-2027
Full structure replacement	144	52	92
Cross arm replacement	102	38	64
Insulator replacement	549	162	387
Total structures replacement	**795**	**252**	**543**
No maintenance required	39	-	-
Total structures	**834**	**252**	**543**

The cost for work completed through 2022 is $5.08 million. The project budget for the 2023 and 2024 test years is $1.0 million and $5.00 million respectively. These costs will be added to ratebase as the work is completed, reflecting the fact that each refurbishment becomes used and useful upon its completion.

The current forecast to complete the project beyond 2024 is $8.55 million, resulting in a total project cost of $19.63 million.

This total project cost has increased substantially from the 2021 GRA estimate of $8.3 million for a number of reasons.

- L178 is the only line in the WAF system that required significant rock blasting in order to replace certain structures.
- Further, the terrain in the area is much less accessible, requiring specialized equipment and increased installation time for each structure. Inflationary pressures have driven both contractor rates and material costs higher than anticipated over the last few years.
- Additionally, the cost to permit and build access roads to the structure locations has been included in the cost of this project (this was planned to be done separately as of the last GRA, similar to the other transmission lines).

Estimates for 2025-27 will be updated based on the results of the 2024 tendering process.

SECTION 5.1A-5: WH1 HEAD GATE REPLACEMENT (RATE BASE ADDITION OF $2.204 MILLION IN 2022)

This project replacing the WH1 head gate is the second head gate replacement of three required at the P125 Hydro Plant.

The P125 Hydro Plant, originally commissioned in 1958, is located at Whitehorse Rapids Generating Station and houses three of the four hydro power units at Whitehorse Rapids (Whitehorse Hydro units 1, 2 and 3). The headgates at the P125 plant are located above the plant at the water intake structure and serve as the single isolation point for the hydro units. The headgates are critical for operating and maintaining the P125 Plant, and play a critical role in ensuring worker safety when isolation is required to inspect the runner and draft tube as well as protecting the hydro units and water conveyance system. Specifically, during upset conditions, the headgates drop to protect the hydro units and the water conveyance system. Prior to 2020, when the WH2 headgate was replaced, the headgates had never been overhauled.

An external engineering firm (SNC Lavalin) performed tests and structural assessments of the P125 headgates in 2019 which indicated that the headgates can no longer be relied upon for emergency closure or for single device isolation. The gates were tested, in a controlled situation, to determine if they would close during emergency conditions and two out of the three gates did not close. This failure could result in a unit runaway/over-speed that could potentially cause severe damage to the unit as well as the plant.

YEC currently installs stop logs in front of the existing headgates to ensure worker safety when dewatering the units; however, this requires additional man hours as well as crane rental, and in the winter months becomes more problematic due to icing.

The WH2 headgate was replaced in 2020 and included some of the design work for the other two units; costs for WH2 headgate replacement were reviewed by the Board in YEC’s 2021 GRA, and final costs for WH2 headgate replacement of $2.221 million are included in the 2023/24 GRA (see section 5.2.1).

The scope of the current WH1 headgate project includes the removal of existing WH1 headgate, installation of new headgate and control system, and refurbishment of the headgate hoist mechanism.

The replacement of the WH3 headgate is currently planned for 2025.

SECTION 5.1A-6: P&C: S250 CALLISON PROTECTION, CONTROL AND SCADA UPGRADE (RATE BASE ADDITION OF $2.125 MILLION IN 2023)

The S250 Callison Substation has been identified as at critical risk of failure due to several factors including protection and control assets like protection relays being at end of life.

This upgrade project as well as multiple other protection, control and SCADA upgrades were identified in a 2020 SNC Lavalin asset management framework report.

Since the report was completed by SNC Lavalin in 2020, protection relays have failed at the substation, leaving equipment exposed to a higher risk of damage and personnel exposed to increased safety risk.

The potential risk of not completing the S250 Callison upgrade includes failure of the protection relays and SCADA remote terminal units which are currently at end of life. Should this equipment fail, there is the potential for an extended outage in Dawson with the possibility of extended diesel usage. This substation is critical to the city of Dawson as it supplies the city with clean renewable energy from the grid as well as backup diesel power to customers on the Hunker Feeder.

The completion of this project also supports other projects in Dawson such as the Thermal Replacement Project (connection the Callison 12.5kV switchgear), the Dawson Voltage Conversion Project, as well as the Synchronous Condenser Overhaul project.

Project Description

This project is to upgrade the Protection, Control, and SCADA communications in the Callison substation, install new S250-52-R2 breakers for reactors R2 and R3 and install a new tap changer control for the Dawson distribution regulating transformer. The SCADA network equipment will also be upgraded with the Thermal Replacement project, the Synchronous Condenser Protection and Controls Upgrade projects in mind. Due to the extensive work required, Dawson City will need to be islanded on diesel for as long as one month with the Callison Substation in a full outage for several weeks.

The primary deliverables include:

- Replacement/recommissioning of all protection relays;
- Upgrading SCADA network equipment and install local fiber, cleanup existing fiber, install new network Cisco switches and operations network;
- Adding of civil and structural steel including new VOX breaker and new PT's;
- Installing and commissioning of the new VOX breaker for reactors R2 and R3;
- Installing and commissioning of the Tap changer Control for the regulating transformer;

- Testing of ground grid post-outage to ensure it meets the modeling and design expectations; and
- Final documentation and updated drawings of the Callison substation.

All contracts related to the project were competitively tendered and awarded as follows:

- Asset Management Plan & Preliminary Engineering – SNC Lavalin
- Detailed Engineering & Design – Phasor Engineering
- Construction & Commissioning – Valard Construction

The project is on schedule for completion in Q4 of 2023.

SECTION 5.1A-7: MH0 ROAD AND ROAD SLOPE STABILITY (RATE BASE ADDITION OF $1.874 MILLION IN 2023)

This project addresses two key safety and reliability issues identified relating to slope stability that affect the area in and around the Mayo Generating Station (MH0 or Mayo A) and that are required to be addressed:

1. The access road to the generating station has started to slough down the hill on the downstream side. The upstream side has started to slough onto the road and has caused issues with the ditching and drainage. The rock and soil slides are forcing drivers to avoid these hazards and drive closer to the downstream edge, where the barrier is failing. This results in unsafe driving conditions (with a high potential for injury), as the guiderail is no longer providing an effective barrier as the top of the guiderail is below the top of the road. As this is a road with sufficient grade, snowfall in the area could create a slippery and sliding condition for a vehicle, where the barriers are not there to mitigate the issues.
2. The second issue is the soil/rock slope around the surge chamber. In 2016, a rock fence was provided, and some slope stabilization was undertaken (on the west side of the surge chamber). The east side of the surge chamber is failing and rock slides have damaged the access platform to the surge chamber. Mitigation put in place in 2016 does not prevent finer material from eroding and building up against the MH0 building. The rock and soil have plugged the drainage in the area causing flooding within the building and on the roadway.

If nothing is done, the road will continue to be blocked and access will be limited and create hazard for operators; slope failure at surge chamber will also progressively get worse and potentially damage infrastructure.

The work for this project will include a rock fence, regrading, earthworks, guiderail installation, and erosion control measures. Road alignment will be assessed and modified for safe access. The road will be regraded, the guiderail will be relocated to provide a safe barrier, the upslope will be shaped to minimize erosion, move the alignment of the road, provide erosion control measures, ditching, and culverts. The slope at surge chamber will be stabilized with rock fencing, erosion control measures, and rock anchors to eliminate rocks causing damage, impeding access and causing silt to build up next to the MH0 building resulting in flooding issues.

This work was direct-awarded to NND Cobalt Mining. This will provide employment to FNNND members in Mayo.

This project was included in the 2021 GRA, but deferred to 2023 to allow for further engineering and planning. Forecast costs in the 2021 GRA were $1.5 million. Costs have increased to $1.874 million in 2023. The increase in costs relate to additional slope excavation that was required.

The majority of work is complete, with hydroseeding to be completed in 2023. The project is forecast to be completed in 2023.

SECTION 5.1A-8: WAREHAM SPILLWAY CONCRETE REPAIR (RATE BASE ADDITION OF $1.845 MILLION – INCLUDES $0.898 MILLION IN SERVICE IN 2021, $0.447 MILLION IN SERVICE IN 2022, AND $0.5 MILLION IN SERVICE IN 2023)

This project addresses interim concrete repairs of the Wareham spillway at the Mayo Generating Station.

Wareham spillway provides the Inflow Design Flood (IDF) capacity to the Wareham Lake system. There is no other spilling structure at Wareham Lake which can pass IDF or spring freshet. If the spillway is not operatable during flood, the lake water levels would rise and eventually overtop the Wareham dam. Being an earthfill dam, the overtopping of the dam is not an option, as this is main failure mode of earthfill dams. Therefore, the inoperability of the spillway during flood increases the risk profile of the Wareham dam significantly.

Over the 1960s through the 1980s, several issues were identified in relation to the Wareham spillway. The erosion of the foundation under the chute and wearing of the concrete surface had been noted since the early 1960s and continued to be an ongoing issue. The spillway chute was in constant repair, and projects in 1970, 1973, 1979, 1985, and 1987 were executed to grout cracks. Movement of the spillway walls was noted in 1970 and addressed in 1976.

In the 2002 Dam Safety Review, it was identified that a concrete overtopping would be required over the spillway chute because the aggregate and joints of the chute had deteriorated to a point where there was a potential for failure of the spillway. The concrete overtopping project began in the late summer/fall of 2004, however the hoarding and construction techniques implemented in the project did not provide for an adequate bond to the existing concrete. A more recent project in late summer 2020 to rehabilitate one of the spillway gates resulted in high water flows being concentrated through the other gate, potentially causing enough uplift on the 2004 overtopping slab that it could have failed catastrophically.

To avoid any further damage and manage failure risk before the 2021 spring freshet, this project was executed to implement an interim repair and monitoring program until the permanent repairs can be completed. Work included an investigation undertaken by Stantec of the root cause analysis (to inform design basis of the repair), repair design, and construction. Following its investigation Stantec developed a recommended solution. Construction work was carried out in December 2020 and April 2021, in advance of the spring freshet. Additional work was completed in 2022 and 2023 based on inspections following the spring freshet each year.

Interim repairs will be continually required until the spillway can be either permanently repaired or replaced. This will be completed under a separate project – Mayo Civil / Structural Infrastructure Program – to be started in 2023.

SECTION 5.1A-9: WHITEHORSE STOPLOG CRANE REPLACEMENT (RATE BASE ADDITION OF $4.247 MILLION IN 2023)

This project replaces the stoplog crane at the Whitehorse spillway gates.

The Whitehorse spillway stoplog crane was built in 1958 and serves the purpose of installing and removing the stoplogs from the Whitehorse spillway gates. These stoplogs hold back Schwatka Lake so the spillway gates can be operated as required for testing, inspection, and maintenance activities. The stoplogs also allow workers to enter the spillway to perform work on the spillway and spillway gates.

Annual inspections have been completed by certified crane technicians every year and numerous safety and reliability issues have been identified in recent inspections. In 2021, an in-depth 3rd party site inspection of the crane was completed by Kone Cranes which identified major issues resulting in the crane being condemned. At this point, the crane could be authorized for a one-time emergency use but is otherwise out of service due to multiple significant issues.

Restoration of an active, safe stoplog crane was required. The option to refurbish the existing crane and related equipment was explored and was initially estimated to cost approximately $600k less than replacement.

However, the owner's engineer subsequently hired for the project (Klohn Crippen Berger) provided a detailed assessment report recommending full replacement for several reasons. These include significant known issues, additional issues that could be found during disassembly, timeframes for construction, and the obsolescence of many of the components.

The following scope of work will be completed as part of this project:

- Design, manufacturing, delivery, installation, testing and commissioning of a new stoplog crane and follower beam.
- Inspection, assessment, and minor repairs and replacement of damaged sections of the existing crane support structure.
- Removal, transport, and salvage / disposal of the existing stoplog crane.
- Supply of tools, equipment, consumables required for this work as well as spare parts and special tools required for trouble free operation and maintenance for five years after commissioning.

The EPC contract was publicly tendered. Project costs are summarized in the table below:

Item	Cost
YEC Costs / PM / Inspections	518,000
Owner's Engineer (KCB)	270,000
Crane and Follower Beam Design, Supply, Installation, and Commissioning	2,870,000
AFUDC (3%)	106,524
Contingency	482,476
Total	**4,247,000**

SECTION 5.1A-10: SCHWATKA LAKE SAFETY / DEBRIS BOOM (RATE BASE ADDITION OF $1.097 MILLION IN 2023)

This project replaces the damaged safety/ debris boom at the Whitehorse main dam at Schwatka Lake.

The Yukon River (Schwatka Lake) experienced an extreme flooding event in the spring of 2021 where very high flows and velocities occurred at the Whitehorse main dam. The high water washed a significant amount of debris from the shoreline that accumulated in the middle of the safety/debris boom. The flows in the water were too dangerous for crews to remove it and high winds caused extra tension on the boom until resulting in failure. Several boom sections were damaged beyond repair and other sections were damaged being removed from the intake area of the spillway.

The boom is necessary to prevent members of the public from approaching the intakes for the spillway or WH4 hydro unit via watercraft. It also prevents debris from accumulating at the same intakes. A functioning safety/debris boom is critical to Yukon Energy meeting the requirements of the Canadian Dam Association.

This project involves the design, engineering, procurement, and installation of a new boom. It is expected to be in-service by summer of 2023. The design was completed by Revelstoke Design Services in late 2022 (cost of $36k) and the supply of the boom material was put out to public tender. The contract for the supply of the boom was awarded to Pacific Netting Products at a cost of $527k. An RFP for installation work was issued in March 2023 and a contract for $432k was awarded to Geniglace Inc. This work is expected to be completed during September 2023.

SECTION 5.1A-11: DAWSON VOLTAGE CONVERSION (RATE BASE ADDITION OF $1.872 MILLION IN 2024)

Dawson City's two 4.16 kV distribution feeders have reached their practical operating limits, resulting in frequent power outages, constant voltage flicker, and longer fault clearing times. Teshmont Consultants LP conducted a site visit to assess the entire 4.16 kV distribution system to identify protection issues, potential voltage levels, transformer utilization and power flow. Teshmont provided its report in 2021, a copy of which was filed during YEC's 2021 GRA proceeding (YUB-YEC-1-66).

The primary issues facing the Dawson distribution system were noted as follows:

- Inadequate protection settings resulting from load growth, increased outage frequency and fault clearing times;
- Long feeders result in low available fault currents at the end of the feeders, with high fault currents at the beginning of the feeder, resulting in potential safety concerns if protective devices fail to operate; and
- Poor voltage at the end of each feeder limiting secondary conductor lengths and forcing underutilization of the transformer capacity.

Teshmont recommended converting the operating voltage of the Dawson City distribution system from 4.16 kV to 12.47 kV in a single stage, including the implementation of revised protection coordination, at a total cost of $833,000.00 (with a 30 year Net Present Value of +$26,000, 28 year payback and a quantifiable benefit /cost ratio of 1.03). Increasing the voltage immediately improves the capacity on the existing conductors, reduces fault current at the primary, reduces voltage drops and decreases energy losses.

Not addressing the issue will result in reliability safety concerns if protective devices fail to operate; damage to customer equipment; and minor fines related to not meeting CEA voltage requirements.

The project is currently forecast to be completed in 2024.

Pending project completion, temporary measures have been implemented such as increasing the breaker trip settings and fuse sizes, which leads the system to experience different types of issues such as brownouts. An interim solution has been implemented which includes a partial voltage conversion to 12.47 kV which has relieved the load on Dome area. A voltage conversion to 24.94 kV was not considered due to the excessive costs.

SECTION 5.1A-12: WHITEHORSE SPILLWAY STOPLOG REFURBISHMENT (RATE BASE ADDITION OF $1.000 MILLION IN 2024)

This project refurbishes the Whitehorse spillway stoplogs.

The Whitehorse spillway is a concrete structure that consists of two spillway bays. There is a single set of stoplogs to allow isolation of one bay at a time. The spillway stoplogs are operated by a stoplog crane and follower beam.

The stoplogs currently do not seal properly and cannot be certified for single device isolation. The timber seals were replaced in 2012, but currently there is significant leakage. The timber seals are cracked in many locations and the top timbers do not appear to be flat or in alignment as required.

The potential impact of not refurbishing or replacing the stoplogs is that work on spillway gates cannot be completed when required as the stoplogs cannot be certified and the stoplogs are likely to become jammed during installation and/or removal.

Refurbishment of the stoplogs has been chosen rather than replacement as it is cost effective and no repairs are required to the steel structure other than recoating them to prevent corrosion.

No significant repairs to the steel structure are recommended in the refurbishment, other than re-coating. This project is to replace the timber seals with rubber seals which is expected to provide a more effective and reliable seal and replace the side guiding bumpers which are missing from the stoplogs. There is significant uncertainty surrounding the forecast cost of this project as it is based on a 3rd party estimate from 2021 and does not include an allowance for price inflation or unanticipated project challenges.

SECTION 51A-13: LEWES RIVER BOAT LOCK ROAD ACCESS REBUILD (RATE BASE ADDITION OF $1.200 MILLION IN 2024)

This project rebuilds road access to the boat lock side of the Lewes River control structure upstream of the Whitehorse Generating Station.

During the flood of 2021, high water eroded away the embankment of the road access to the boat lock side of the Lewes River control structure. A subsequent assessment performed by a 3rd party geotechnical engineer (Tetra Tech) determined that it was in an unsafe condition for vehicle use. The access was barricaded, and a temporary access was utilized. Further high-water events combined with erosion from spring freshet have caused further deterioration of the existing access road.

There are two options for restoring access to the east side of Lewes:

1. Restore the original access; or
2. Upgrade the temporary access and have a disposition so that YEC has permanent access.

Leaving the damaged road in its current condition is not an option as proper access is required for rebuilding the damaged boat lock and long-term inspection work.

A request for proposal for a design engineer is being completed in 2023, and design should be ready by year-end.

As part of this contract, the two options will be assessed and determined which one will be the most cost effective to both restore/upgrade and maintain.

The construction will be completed during the 2024 construction season in order have the road ready for 2025 repair of the boat lock.

SECTION 5.1A-14: WH2 UPRATE CONSTRUCTION AND ENGINEERING (RATE BASE ADDITION OF $7.078 MILLION TO 2021 GRA APPROVED)

Board Order 2022-10 regarding YEC's 2021 GRA disallowed over 50% of YEC's capital costs for the Whitehorse Hydro #2 (WH2) Uprate project, noting (Appendix A, para 277-278) that YEC never discussed the reasons for cost differences between the earlier Hatch study estimates and YEC's actual costs, nor did it adequately explain the reasons the project was the preferred alternative. Board Order 2022-10 (Appendix A, para 38) rejected YEC's application for review and variance of this decision on the WH2 Uprate costs, noting that the Board relied on the evidence and arguments before it in making the findings to reduce the costs, and that generally the Board found that the business case was deficient for this project and that there was a lack of information in the other evidence to justify the significant cost increases and a lack of an adequate justification of costs and benefits.

The following business case for the WH2 Uprate project reviews the available evidence on this project to address the Board's earlier findings regarding the deficiency of evidence provided during the last GRA, and to provide the basis for approving in the current GRA ongoing inclusion of all costs in the rate base to be recovered through rates.

Background

Whitehorse Rapids Generating Station (WRGS) Unit #2 (WH2) was commissioned in 1958 and is one of the three units installed at P125. It is a Kaplan Turbine unit with nominal rating of a 5.8 MW and was operating with the original runner, rotor, stator and windings from 1958 before the uprate. WH2 asset health was declining due to its age, and there was an increased risk of failure and related unplanned outages and costs. Specifically, the generator has exceeded a typical winding life of 40 years; and issues were identified with oil leaks at the runner blade to hub seals and with possible voids in the concrete behind the draft tube liner. In the circumstances, it was considered prudent to rewind the generator in order to mitigate these risks and their potential reliability and cost implications.

The 2016 Yukon Energy Resource Plan identified hydro uprate projects as an economically attractive option to help address YEC's existing and forecast capacity shortfall, as well as providing a cost-effective incremental source of firm renewable energy as uprate projects were expected to provide an incremental source of renewable energy to offset thermal generation as load grows on the YEC system. As such, uprating of the Whitehorse hydro units were included in the recommended near-term action plan under the 'base case' load scenario.

In 2017, Hatch completed an economic assessment of various uprate options at the WRGS. The report concluded that the uprating of the WH1 or WH2 Kaplan units would be the most cost-effective option and provide the best payback for the WRGS hydro units. Management selected the uprating of WH2 over WH1 since there are existing known issues with the WH2 governor, and the uprating project would resolve these issues. Hatch estimated a cost of $4.78 million (2017$) specifically for the WH #1 turbine uprate project[16], and noted that this estimate excluded additional turbine and installation work that would also be required, in any event, regardless of YEC's uprating plans. When dealing with the unit outage time estimated in the preliminary schedule, Hatch noted: "This allows some time for turbine and generator rehabilitation that would typically be done when the equipment is dismantled. The rehabilitation work is not attributed to the uprate; therefore it is not included in the capital cost discussed above."[17]

The WH2 Uprate project was undertaken over a three-year period (2019-21). As anticipated in the Hatch report, the final project scope went well beyond the uprate scope identified in the Hatch report to include other required rehabilitation work that can reasonably be done when the equipment is dismantled, including unit rehabilitation, runner replacement, generator stator and rotor rewinding, governor replacement, exciter replacement, upgrading the control and condition monitoring systems, and rehabilitation of the tailrace crane superstructure and concrete piers.

Yukon Energy contracted Litostroj Power to undertake the runner fabrication, governor fabrication, balance of plant civil construction, balance of plant P&C design completion, release of balance of plant request for proposal, and delivery of materials to Whitehorse. The balance of plant civil scope work included rehabilitation of the tailrace crane superstructure and concrete piers.

The project was completed in 2021. The total final cost of the Project is $12.814 million which is slightly higher than the forecast cost included in the 2021 GRA of $12.526 million.[18]

The Yukon Utilities Board (YUB) in its Order 2022-03, Appendix A, para 278 noted that "Given the Board's concerns with the reasonableness of the costs, the recommendations in the Hatch report and the deficiencies in the business case, the Board finds it appropriate to approve costs of $4.78 million, which was the Hatch cost estimate for uprating a unit with increased turbine flow, plus 20 percent for cost overruns." Therefore, the total approved project cost in Order 2022-03 was $5.7 million [$4.78 million

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[16] Hatch, **Engineering Report – WH1, WH3 and WH 4 Turbine Uprate Study**, April 2017, Table 3-2, page 16. This report was provided in the 2021 GRA proceeding as Attachment 1 to YUB-YEC-1-57(d). The cost estimate for WH1 uprate also applied to WH2 uprate (same Kaplan turbines).
[17] Ibid; pages 16.
[18] The 2021 GRA included the cost of $12.526 million as per YUB-YEC-2-17 [$12.267 million plus $0.259 million included under deferred costs].

plus 20%], and the balance of YEC's capital costs (representing over 50% of total project costs) were disallowed.

Issues raised by Yukon Utilities Board

In order to facilitate review of this updated business case for the WH2 Uprate project, the following addresses specific business case deficiency issues set out by the YUB in its Order 2022-03.

The Project cost:

YUB in its Order 2022-03, Appendix A, para 277 stated the following:

> YEC's costs for this project were $12.267 million even though Hatch's cost estimates for uprating the WH1 unit, which would be similar to the cost estimates for uprating the WH2 unit, were approximately $1.99 million with the same original turbine flow and $4.78 million with an increase in turbine flow. However, YEC never discussed the reasons for these cost differences in its business case or why the WH2 Uprate Project exceeded the Hatch estimates.

YUB Order 2022-10, Appendix A, para 38:

> "there was a lack of information in the other evidence to justify the significant cost increases for these projects from the estimated costs and a lack of an adequate justification of costs and benefits."

As reviewed above. the Hatch 2017 report provided a high-level initial cost estimate that was restricted only to the turbine uprate. Hatch cost estimates for WH2 Uprate as provided in its report were also in 2017$ and did not include YEC costs (owner's engineer, AFUDC, internal cost and project management) beyond the provision of 10% for "engineering and administration". The actual project costs materially exceeded Hatch's original estimate (aside from escalations due to timing differences) because of additional necessary refurbishing and related work that was outside the scope of the original Hatch turbine uprate estimate.

YEC's actual costs as updated for the WH2 uprate project of $12.814 million include costs incurred in 2019 to 2023[19] (i.e., reflect cost escalations after 2017 cost estimates and extended scope as reviewed

[19] The project was closed in 2021 with total cost of $12.358 million. Additional spending of $0.456 million occurred in 2022-2023 years for remaining commissioning project closeout activities that could be completed with the unit online.

below) with $8.714 million for contractor for turbine and generator and $4.100 million for owner's engineer, internal costs and project management, balance of plant and AFUDC.

The WH2 Uprate project scope as approved by YEC's Board addressed WH2 refurbishment elements and was not restricted to turbine uprate requirements. The final scope of work for the WH2 uprate project included unit rehabilitation, runner replacement, generator stator and rotor rewinding, governor replacement, exciter replacement, upgrading the control and condition monitoring systems, and rehabilitation of the tailrace crane superstructure and concrete piers, i.e., the project actual scope went well beyond the scope for the Hatch cost estimates in the 2017 study.

In addition to the above approved scope, once the WH2 unit was disassembled (i.e., after business case assessments and when actual implementation was underway), assessments of both the embedded components as well as the removable components were also undertaken (this assessment can only be undertaken upon completion of disassembly). These assessments revealed in many cases that the condition of the components was worse than originally expected, and these components had to be refurbished as part of the project to ensure proper operation and acceptable service life of the unit. In addition, during the inspection and assessment process certain components of the WH2 unit were found to be misaligned – this discovery resulted in the need for additional machining of several components to bring the items back into proper alignment.

WH2 had been in service for approximately 60 years prior to the uprate project with most of the components being original. When developing the specifications for the project, YEC identified a number of systems associated with WH2 that were at end of life including the governor, excitation system, oil head, turbine shaft seal, greased bushing system, HPU and unit controls. YEC followed recommendations from engineering and operations that it was essential to replace these aged assets, to ensure their continued reliability and to extend the life of the unit by approximately 40 years.

It was less costly, and therefore prudent, to undertake these required system replacements during the uprate project rather than as a separate project conducted at another time. The Hatch report specifically acknowledged the prudency of such an approach, indicating that their schedule for the uprate work "allows some time for turbine and generator rehabilitation work that would typically be done when the equipment is dismantled" further noting that "the rehabilitation work is not attributed to the uprate; therefore it is not included in the capital cost discussed above."[20]

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[20] Hatch 2017 Study page 16 [the copy of the study was provided in the 2021 GRA proceeding as Attachment 1 to YUB-YEC-1-57(d)].

The following table compares the project's actual cost and Hatch's 2017 estimate. The actual Turbine & Generator cost of $8.714 million is approximately $1.6 million higher than the initial contract budget, indicating impacts from necessary added work revealed to be required during construction.

$000	Total Actual Cost	Hatch 2017 Study[1,2]
Owner's Engineer	1,154	435
Internal Costs & Project mgmt	1,361	
Turbine & Generator	8,714	3,740
Balance of plant	1,586	40
Contingency		567
Total	**12,814**	**4,782**

Notes:

1. The Hatch estimate did not include any work beyond the turbine uprate, and did not include YEC costs (owner's engineer, internal cost and project management, AFUDC) beyond the provision of 10% for "engineering and administration" at $0.435 million. The actual project costs materially exceeded Hatch's original estimate (aside from escalations due to timing differences) because of additional necessary work that was outside the scope of the original estimate.
2. The Hatch estimate was completed before a detailed plan for the WH2 uprate project was completed to include a range of added rehabilitation works. In addition, once the unit was disassembled, a range of additional refurbishment requirements were identified (see text). The Hatch estimate did not include any of the added work required to extend the life of the unit. Many systems were at end of life and the uprate scope ended up including a governor replacement, exciter upgrade, protection and control upgrades and significant repairs to most hydro-mechanical components. This additional work was needed to ensure the unit's continued service over the projected life extension expected from the uprate.

Alternatives:

YUB Order 2022-03, Appendix A, para 277 stated the following:

> Additionally, Hatch presented an alternative in its report that also allowed for efficiency gain of two percent and an offset in thermal generation half of that achieved with the WH2 Uprate Project. YEC did not discuss this alternative, any costs associated with this alternative, and the reasons for dismissing this alternative over the proposed project in its business case. While the metrics associated with Hatch's alternative are quantified at a lesser value compared to the WH2 Uprate Project, the Board finds that the reduction in efficiency gain and thermal generation offset is not notably significant.

YEC understands that the YUB is referring to the statement in Hatch 2017 study (page 8) where Hatch notes the following:

> It is possible to replace only the runner blades, keeping the same runner hub including the internal blade operating mechanism. Equipment cost would be reduced for this option. However, it is expected that the level of efficiency increase would not match that of a complete new runner, and would perhaps be 50% of the increase as compared to a completely new runner, there would also be increased uncertainty in the performance of the new runner. Furthermore, fitting the new runner blades to the existing runner hub would require an increased outage for the uprate project as this could not be done until the existing generating unit was dismantled. [underlining added]

The above underlined statement in the Hatch study already dismisses the option with 2% efficiency increase [i.e., 50% of the efficiency gain with a new runner] noting that there would also be increased uncertainty in the performance of the new runner and fitting the new runner blades to the existing runner hub would require an increased outage for the uprate project as this could not be done until the existing generating unit was dismantled. Based on these considerations, the option of a complete new runner was adopted for the project.

During the 2021 GRA Information Request process there were also questions regarding what process was carried out to determine that WH2 required uprating over WH1. As indicated in response to YUB-YEC-1-57 (e) in the 2021 GRA proceeding, WH2 was selected over WH1 because the energy output of WH2 was higher based on the plant configuration. That is, WH2 produces more energy because it exhausts mid-stream; WH1 exhausts against the bank of the river which creates a loss of efficiency. Otherwise, the units are essentially identical units. Additionally, WH2 was having a problem with its governor, i.e., the WH2 governor was having issues with MW control and a resolution was required.

In addition to the above features favoring WH2 compared to WH1, it can be noted that WH2 is a Kaplan turbine with a broad range of high efficiency. It is advantageous to run the unit in the winter to follow the load when trying to conserve water. In contrast, WH3 and WH4 are fixed blade propeller units with a narrow range of high efficiency. The efficiency gains from WH2 can be used to conserve water in the winter, adding to the benefits gained from uprating the unit.

No other renewable option providing similar benefits could be completed in the same timeframe [WH uprate was completed over a two-year period].

Project Benefits:

YUB Order 2022-03, Appendix A, para 277 stated the following:

> Finally, while Hatch concluded a positive economic benefit from the project, it indicated uncertainty in both the measured performance of the existing unit and the predicted performance of an uprated turbine. Hatch also commented that the payback period was fairly long even under higher demand assumptions.

YUB Order 2022-10, Appendix A, para 38 stated the following:

> There was a lack of information in the other evidence to justify the significant cost increases for these projects from the estimated costs and a lack of an adequate justification of costs and benefits.

The 2016 Yukon Energy Resource Plan identified hydro uprate projects as an economically attractive option to help address YEC's existing and forecast capacity shortfall, as well as providing a cost-effective incremental source of firm renewable energy as the project was expected to provide an incremental source of renewable energy to offset thermal generation as load grows on the YEC system. As such, the option was included in the recommended near-term action plan.

The project benefits were included in the 2021 GRA as referenced in Appendix 2.1, Table 2.1-1 [LTA thermal calculation table], note #7 where YEC noted the following:

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

The following table shows the benefits of the WH2 uprate and WH4 servomotor projects using 2021 GRA Appendix 2.1, Table 2.1-1 [LTA thermal calculation table]. The table shows that 7.1 GWh incremental hydro generation from WH2 and WH4 projects displaces 5.9 GWh thermal on an LTA basis.

		With Uprates MWh	No Uprates MWh
1	YEC Grid load net of expected Fish Lake and IPPs [2021 GRA]	538,724	538,724
2	WH2 and WH4 Uprates [2021 GRA, App 2.1, Table 2.1-1 note #7]	7,100	
3=1-2	Load net of WH2 and WH4 Uprates	531,624	538,724
4=3 Rounded	Rounding to Lower Five Thousand	530,000	535,000
5	Expected LTA Thermal at Rounded Load [2021 GRA, App 2.1, Table 2.1-1]	82,231	86,346
6=3-4	Load above Rounded Load	1,624	3,724
7	LTA Thermal as % of Incremental Load [2021 GRA, App 2.1, Table 2.1-1]	82%	84%
8=6*7	LTA Thermal above the Rounded Load	1,331	3,128
9=5+8	LTA Thermal Generation at Total Load	83,562	89,473
	LTA Thermal reduction from WH2 and WH4 Uprates		5,911

Similarly, 2023/24 GRA Appendix 2.1, Table 2.1-1 [LTA thermal calculation table] includes benefits from WH2 and WH4 projects.[21] The table shows with WH2 and WH4 projects the LTA thermal at the 2024 test year load is 68.0 GWh. Without these projects, the LTA thermal would be 73.5 GWh, i.e., WH2 and WH4 projects displace 5.5 GWh thermal on an LTA basis.[22] Based on 2023/24 GRA thermal generation cost of $0.20/kWh [90% LNG and 10% diesel], the annual LTA thermal displacement benefits from WH2 and WH4 projects included in the 2023/24 GRA is $1.120 million. It is estimated that approximately 90% of these LTA thermal displacement benefits relate to the WH2 Uprate project and the remaining 10% to the WH4 Servomotor project.[23]

The 2023/24 GRA also includes dependable capacity benefits from the WH2 Uprate project. As reviewed in Tab 2 of the 2023/24 GRA, for the test years the dependable capacity from hydro units is increased from 70.5 MW in the 2021 GRA to 71.1 MW, an increase of 0.6 MW[24]. This is about 1/3 of one diesel rental unit [1.8 MW]. With the average annual cost of rental of $162,017/MW for 2024 for the Whitehorse location, the dependable capacity benefits from WH2 Uprate is $97,210/year.

Based on the information provided above, the total incremental annual benefits included in the 2023/24 GRA from WH2 uprates is $1.105 million compared to the annual revenue requirement cost of no more than $0.885 million included in the 2023/24 GRA for this project.[25] This indicates that the project reduces the cost to ratepayers before considering the environmental benefits of the project [e.g., reduced GHG

[21] YECSIM inputs are updated to reflect the benefits of WH2 and WH4 projects. Thus 2023/24 GRA Appendix 2.1, Table 2.1-1 already includes incremental hydro generation from these projects.
[22] Slightly lower than the 2021 GRA estimate due to lower loads without Minto as an industrial customer.
[23] The 10-Year Renewable Electricity Plan [as provided in response to CW-YEC-1-36 during the 2021 GRA review] notes that the WH2 Uprate project will provide approximately 6.2 GWh of annual energy while the WH4 servomotor project will increase the hydro output by 0.9 GWh. Based on this about 90% of the LTA thermal displacement benefits relate to the WH2 Uprate project and the remaining 10% to the WH4 servomotor project.
[24] The 10-Year Renewable Electricity Plan [provided in response to CW-YEC-1-36 in the 2021 GRA] notes that WH2 is included as a planned/under-development project and will provide at least 0.64 MW of dependable capacity.
[25] The annual revenue requirement for WH2 uprate project is $0.885 million which reflects annual depreciation based on the project life of 72 years and return on initial year rate base based on the 2023 weighted average cost of debt and equity of 5.56% (this cost goes down for each subsequent year due to depreciation reductions of rate base).

emissions and reliance on fossil fuel generation]. The benefits over the project life would be even higher as the annual cost of capital reduces over the years as the cost is depreciated.

The above assessment focuses only on the incremental benefits derived from the uprate component of the WH2 and WH4 projects. As reviewed earlier, a material portion of the costs for the WH2 Uprate project were not related to the uprate element, and addressed refurbishments needed to extend the life of this hydro project. The benefits of this extended renewable project life provide added cost savings for ratepayers compared to the option of developing new renewable resources or relying on existing thermal energy resources.

Overall, the project provides for better use of the Whitehorse Hydro Generating Facility, ensuring renewable generation is retained and added to the Yukon Integrated System which aligns with the direction provided in section 11 of OIC 1995/090 (as amended by OIC 2021/16), which requires the Board to include provision in rates to enable YEC to recover costs it reasonably incurs to plan or develop renewable generation projects.

SECTION 5.1A-15: WH4 SERVOMOTOR REPLACEMENT (RATE BASE ADDITION OF $0.789 MILLION TO 2021 GRA APPROVED)

Board Order 2022-10 regarding YEC's 2021 GRA disallowed over 60% of YEC's capital costs for the Whitehorse Hydro #4 (WH4) Servomotor Replacement project, noting (Appendix A, para 281-282) that YEC did not provide an adequate business case or justification that supports the significant cost increase from the original Hatch cost estimate, and that the benefits espoused by YEC do not fully justify the costs that were incurred or forecast for this project.

Board Order 2022-10 (Appendix A, para 38) rejected YEC's application for review and variance of this decision on the WH4 Servomotor Replacement costs, noting that the Board relied on the evidence and arguments before it in making the findings to reduce the costs, and that generally the Board found that the business case was deficient for this project and that there was a lack of information in the other evidence to justify the significant cost increases and a lack of an adequate justification of costs and benefits.

The following business case for the WH4 Servomotor Replacement project reviews the available evidence on this project to address the Board's earlier findings regarding the deficiency of evidence provided during the last GRA, and to provide the basis for approving in the current GRA ongoing inclusion of all costs in the rate base to be recovered through rates.

Background

The WH4 Servomotor Replacement project involves detailed design, procurement and installation of two new Servomotors for Whitehorse Rapids Generating Station (WRGS) Unit #4 (WH4) wicket gate operation. Implementation will increase the output of the WH4 unit by allowing full range of operation of the wicket gates; this enhancement adds additional hydraulic generation. Secondary benefits include reduced stress levels in the servo-motors, governor and wickets gates/operating ring which will increase reliability and safety during operation.

The original servomotors were installed in 1984 and the expected service life at time of installation is not known. The original servomotors were not meeting IEEE code in terms of operation and reliability.

With the original servomotors WH4 unit was limited to 92% gate opening as a result of undersized servomotors. This limitation resulted in a reduction of the unit output as compared to the nameplate rating. The ability to operate at 100% gate opening increases energy and capacity of the unit.

Yukon Energy retained Hatch in 2017 to undertake a desktop study for evaluating the maximum MW available on the turbine shaft and potential impact of higher power on the governor system. Hatch confirmed that the servomotors did not have the capacity to overcome the wicket gate stall force that is recommended in IEEE 1207[26]. Hatch provided a cost estimate of $457,000 to replace the existing servomotors – this cost estimate included only upgrades required to address technical constraints arising from gate opening past 92% or the existing deficiencies, i.e., upgrades required due to existing equipment condition were not included in the estimate.[27]

Yukon Energy entered into a contract with ANDRITZ Hydro for the design and supply of two new servomotors. Other work proceeded in parallel including planning for changes to the governor, signature testing and characteristic testing with assistance from Hatch and L&S Electric.

The project was completed in 2021. The total cost of the Project is $1.337 million which is slightly lower than the forecast cost included in the 2021 GRA of $1.400 million.[28]

Yukon Utilities Board (YUB) in its Order 2022-03, Appendix A, para 282 noted that "given the Board's concerns with the reasonableness of the costs and a lack of a business case for the project to support the magnitude of costs compared to the expected benefits for the project, the Board finds it appropriate to approve costs of $457,000 based on the Hatch cost estimate, plus 20 percent for cost overruns, which amounts to $548,400."

Issues raised by Yukon Utilities Board

In order to facilitate review of this updated business case for the WH4 Servomotor Replacement project, the following addresses specific business case deficiency issues set out by the YUB in its Order 2022-03.

The Project cost:

YUB in its Order 2022-03, Appendix A, stated the following as part of para 291:

> The Board finds there is a value for the WH4 Uprate Servomotor Replacement Project in 2021 but is not persuaded that the applied-for costs are reasonable. YEC, as part of its responses to the Board's second round of information requests, provided the Hatch report's recommendation to

[26] See Table 4-2 in Hatch, **Whitehorse Generating Station WH4 Capacity Increase Desktop Study**, Nov 2017. This report was provided in the 2021 GRA, YUB-YEC-2-23 (a), Attachment 1.
[27] Ibid., Section 6, page 14.
[28] YUB-YEC-2-17 from the 2021 GRA.

replace the existing servomotors. In that report, Hatch provided a cost estimate of $457,000 for replacing the servomotors. During the proceeding, YEC did not explain why the costs for this project increased from the original Hatch cost estimate. Thus, the Board finds that YEC did not provide an adequate business case or justification that supports the significant cost increase from the original Hatch estimate.

The Hatch 2017 report provided a high-level initial cost estimate. Hatch cost estimates for servomotor were in 2017$ and did not include YEC costs (owner's engineer, AFUDC, internal cost and project management) or any allowances for installation and commissioning or balance of plant.

YEC's actual costs as updated for the WH4 Servomotor Replacement project of $1.337 million. The following table compares the project's actual cost and Hatch's 2017 estimate.

($000)	**Total Actual Cost**	**Hatch 2017 Study**
Servomotor supplier	750	457
Owner's Engineer	49	
Internal Costs & Project Mgmt	346	
Balance of Plant	192	
Total	**1,337**	**457**

The servomotor cost increase of $0.293 million in 2021 compared with the Hatch study estimate reflected cost escalations after the 2017 cost estimates plus final design requirements and supplier costs for this work. Replacing the original servomotors with custom spring assisted servomotors was a significant change to the WH4 unit and required extensive analysis and testing to verify the unit was capable of handling the added flow and that servomotors could be relied upon for safe unit operation.

The final project cost also included $0.587 million for required and prudently incurred costs excluded from the Hatch estimate, i.e., $0.049 million for owner's engineer, $ 0.346 million for internal costs and project management, and $0.208 million for balance of plant that consists of a monorail lifting beam to remove/install the servomotors, the piping modifications and the new governor parts and tuning.

Project Benefits:

YUB Order 2022-03, Appendix A, stated the following as part of para 281:

> The Board finds that the benefits espoused by YEC do not fully justify the costs that were incurred or forecast for this project. The WH4 unit will have an additional maximum output of 0.8 MW once this project is completed, but the unit will not always be operating at its maximum output. Additionally, the improvement in operating the unit with 100-percent gate opening is not significant, especially when the unit was operating with 92-percent gate opening.

Aside from benefits related to added energy generation, the WH4 Servomotor Replacement project was required to provide the capacity to overcome the wicket gate stall force that is recommended in IEE 1207.

The project's energy generation benefits are included in the 2021 GRA as referenced in Appendix 2.1, Table 2.1-1 [LTA thermal calculation table], note #7 where YEC noted the following:

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

The following table shows the benefits of the WH2 uprate and WH4 servomotor projects using 2021 GRA Appendix 2.1, Table 2.1-1 [LTA thermal calculation table]. The table shows that 7.1 GWh incremental hydro generation from WH2 and WH4 projects displaces 5.9 GWh thermal on an LTA basis.

		With Uprates MWh	No Uprates MWh
1	YEC Grid load net of expected Fish Lake and IPPs [2021 GRA]	538,724	538,724
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*8=6*7*	LTA Thermal above the Rounded Load	1,331	3,128
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	LTA Thermal reduction from WH2 and WH4 Uprates		5,911

Similarly, 2023/24 GRA Appendix 2.1, Table 2.1-1 [LTA thermal calculation table] includes benefits from WH2 and WH4 projects.[29] The table shows with WH2 and WH4 projects the LTA thermal at the 2024 test year load is 68.0 GWh. Without these projects, the LTA thermal would be 73.5 GWh, i.e., WH2 and WH4 projects displace 5.5 GWh thermal on an LTA basis.[30] Based on 2023/24 GRA thermal generation cost of $0.20/kWh [90% LNG and 10% diesel], the annual LTA thermal displacement benefits from WH2 and WH4 projects included in the 2023/24 GRA is $1.120 million. It is estimated that approximately 90% of these LTA thermal displacement benefits relate to the WH2 Uprate project and the remaining 10% to the WH4 Servomotor project.[31]

Based on the information provided above, the total incremental benefits included in the 2023/24 GRA from WH4 Servomotor Replacements is $0.112 million compared to the annual revenue requirement cost of no more than $0.089 million included in the 2023/24 GRA for this project.[32] This indicates that the project reduces the cost to ratepayers before considering the environmental benefits of the project [e.g., reduced GHG emissions and reliance on fossil fuel generation]. The benefits over the project life would be even higher as the annual cost of capital reduces over the years as the cost is depreciated.

[29] YECSIM inputs are updated to reflect the benefits of WH2 and WH4 projects. Thus 2023/24 GRA Appendix 2.1, Table 2.1-1 already includes incremental hydro generation from these projects.
[30] Slightly lower than the 2021 GRA estimate due to lower loads without Minto as an industrial customer.
[31] The 10-Year Renewable Electricity Plan [as provided in response to CW-YEC-1-36 during the 2021 GRA review] notes that the WH2 Uprate project will provide approximately 6.2 GWh of annual energy while the WH4 servomotor project will increase the hydro output by 0.9 GWh. Based on this about 90% of the LTA thermal displacement benefits relate to the WH2 Uprate project and the remaining 10% to the WH4 servomotor project.
[32] The annual revenue requirement for WH4 Servomotor project is $0.089 million which reflects annual depreciation based on the project life of 85 years and return on rate base based on the 2024 weighted average cost of debt and equity of 5.54% (this cost goes down for each subsequent year due to depreciation reductions of rate base).

APPENDIX 5.1B
CAPITAL PROJECTS >$100,000 AND <$1 MILLION
ADDED TO RATE BASE

APPENDIX 5.1B: CAPITAL PROJECTS >$100,000 AND <$1 MILLION ADDED TO RATE BASE

Appendix 5.1B summarizes PP&E capital projects over $100,000 but less than $1 million that will be added to rate base in the test years. Details on project costs are summarized in Tables 5.2 to 5.6. Summaries for each of the projects included in Tables 5.2 to 5.6, and additions to rate base by year by cost category (i.e., generation, transmission, distribution, and general plant and equipment) are provided in business case reviews that follow. These business case reviews also include rate base additions over $100,000 for overhauls, right of use assets, RFID, and reserve for site restoration.

5.1B-1: GENERATION PROJECTS

There was approximately $1.095 million added to rate base in 2021 on generation projects $100,000 to $1 million; $1.240 million added in 2022; and $0.286 million forecast to be added for the 2023 test year and $1.000 million forecast in the 2024 test year. The total forecast 2024 rate base increase from these generation projects approximates $3.620 million, excluding any depreciation or amortization deductions. Rate base additions relate to the following projects:

- Wareham Spillway – Gate Refurbishment ($0.483 million in 2021);
- Wareham Spillway Stoplogs – New Set ($0.385 million in 2021);
- WH1 & 2 Penstock Repair ($0.227 million in 2021);
- Faro Fuel System ($0.991 million in 2022);
- WH3 Tailrace Gate Certification ($0.249 million in 2022);
- MBH1/2 Seal Water Filtration ($0.286 million in 2023);
- WH4 Air Admission Valve Automation ($0.200 million in 2024);
- WG2 Cylinder Head Swap ($0.500 million in 2024); and
- WG1 Radiator Replacement ($0.300 million in 2024).

Wareham Spillway - Gate Refurbishment	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
	$0.483 million			

Overview

The Wareham Dam impounds Wareham Lake and is classified as an extreme hazard Dam. The Wareham Spillway Gates have been in service since 1953 and are critical infrastructure for the Wareham Dam. The spillway gates at Wareham Dam have had significant leakage problems over a number of years, primarily due to age-related wear and corrosion. Spending was required to address a number of identified issues and repairs related to the Wareham Spillway gates.

Analysis and Conclusion

Recent observations, including an external engineering assessment, indicated that the gates were deteriorating. Specifically, the skinplates were experiencing pitting corrosion and needed to be repaired by sandblasting, adding additional plates and plug welding and seal welding the plates in an array to add strength. During testing of the hoist following repairs in 2019, extremely high friction forces were also observed acting on the gate; the wheel bushing was worn; and there was evidence of fretting wear on the wheel paths. Side seals were also leaking at a high rate at times; and copper staunching rod links and retaining clips required refurbishment with new self lubricated bushings to allow them to seal smoothly. Spending was focused on undertaking work identified above to address each of these issues.

As operation of the spillway is a critical part of Mayo Generating Station dam safety, issues with the gates raise reliability and safety concerns. YEC is required to maintain critical infrastructure at the Wareham Dam in accordance with CDA standards; and the existing EPP requires the gates to function at all times. As such, there was no alternative to undertaking this work.

The 2021 GRA response to YUB-YEC-2-17 noted this project was deferred in 2020 due to the high water conditions in Mayo Lake. In Order 2022-03 the Board indicated that the costs for this project were reasonable and directed YEC to include updated costs for any projects completed prior to or during the 2021 test period. The Board noted that costs would only be added to rate base once YEC provides the actual capital spending amount in the next GRA and demonstrates the costs were prudently incurred.

Additional work requirements were identified in the 2020 Dam Safety review after the GRA submission. The expenditures were closed in 2021 with final costs of $482,800.

Wareham Spillway Stoplogs – New Set	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
	$0.385 million			

Overview

This project addresses the need for a second set of stoplogs for the Wareham spillway that can be certified to safely work on the spillway structure.

Analysis and Conclusion

YEC only had one set of stoplogs for the Wareham dam. At the time this was suitable for regular maintenance and inspection of the spillway gates as only one of the two spillway gates needed to be isolated at a time.

Due to the spillway concrete damage that occurred in 2020, it was necessary to isolate both spillway bays at the same time in order to complete the repair work. Due to the design and age of the spillway gates, they are not able to be certified for Single Device Isolation. As a result, a second set of stoplogs that can be certified was required in order to safely work on the spillway structure. This was required to complete the repairs and there was no other feasible alternative.

The new stoplogs were certified by BBA Engineering after reviewing the design drawings and witnessing the installation and isolation procedures on site.

Critical spillway repair work was subsequently carried out during 2021 and 2022.

WH 1 & 2 Penstock Repair	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
	$0.227 million			

Overview

Costs related to the WH1 & WH2 Penstock Failure charged in 2020 reflect the insurance deductible and assumed the remaining costs would be 100% insured. Total project costs were $6.075 million; and the insurance claim was $5.899 million, leaving an uninsured about of $0.601 million.

Analysis and Conclusion

The portion of the project not covered by insurance primarily related to grouting work to fit the voids beneath the penstock. $0.374 million was charged to the RFID account. $0.227 million was incurred after the RFID account was had been settled for the year and was capitalized.

Faro Fuel System	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
		$0.991 million		

Overview

In 2020, temporary diesel generator infrastructure was installed in Faro to ensure Yukon Energy was able to meet its N-1 capacity planning requirements. The fuel system installed as part of that project required the manual transfer of fuel between the bulk storage tanks and the individual unit tanks. This was originally completed by two operations staff using a long hose to fill the tanks as needed, however, this method posed a significant health & safety risk. Subsequently, a fuel truck was rented to transfer fuel from the bulk tanks to the truck, and then from the truck to the individual unit tanks.

Analysis and Conclusion

After operating the rental diesel generators under this scenario for the 2020-2021 winter season, it was determined that the O&M truck rental costs and increased spill hazard risk of frequent manual fuel transfers should be avoided. Annual costs for the rental truck were approximately $22,000. Using the rental trucks was labour intensive and considered inefficient from an operational perspective.

This project involved the installation of permanent hoses connecting each individual unit tank to the bulk fuel supply, pumps, and flow monitors resulting in a fully automated fuel supply system. This significantly reduced both employee health & safety risk and environmental spill risk and also avoided the need to rent a fuel truck for future winter seasons. The project was completed in 2022 and is in service.

WH3 Tailrace Gate Certification	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
		$0.249 million		

Overview

A hydro unit's tailrace gates are used to dewater the unit in order to perform underside maintenance. These gates must be certified as single device isolation in order to comply with health and safety regulations.

Analysis and Conclusion

Due to age and condition, the two tailrace gates for WH3 have not been able to be certified for three years. This has resulted in operations being unable to perform required underside maintenance on this unit. One of the gates was bent and required replacement, and the other gate needed to be refurbished. After review by BBA Engineering that would provide certification for the new and refurbished gates, it was determined that the extent of repairs to the old gate was significant. As the cost of refurbishment was greater than the new gate, it was decided to replace them both.

Two new gates were purchased in October of 2022 and single device isolation certification was provided by BBA Engineering. This certification is valid for five years and will allow for planned maintenance and emergency repairs to the underside of the unit as required.

MBH1/2 Seal Water Filtration	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
			$0.286 million	

Overview

The current water filtration systems on MBH1 and MBH2 have issues that require increasing corrective maintenance work, including heavy rust and corrosion (often requiring machining) as well as sticking solenoid valves and need to be replaced. This project relates to the replacement of water filtration systems for MBH1 and MBH2.

Analysis and Conclusion

The current seal water filtration systems on MBH1 and MBH2 are from China and replacement parts are difficult to source and expensive.

The project will evaluate the filtration requirements of the shaft seals (changed from the originals in 2017) and procure and install an appropriate North American filtration system. This is expected to result in reduced maintenance costs going forward.

Evaluation and specifications were provided by LDV Consultants ($15k), and Concept VPS Inc. is supplying and installing the seals ($175k). The balance of project costs are YEC internal costs (labour, travel, AFUDC, contingency).

WH4 Air Admission Valve Automation	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
				$0.200 million

Overview

The WH4 Hydro unit, YEC's largest hydro unit, has a manual valve that allows air to enter the draft tube. This valve is important for stabilizing the flow at lower outputs but decreases efficiency at higher outputs. This project will install an automated isolation valve that will open and close depending on output.

Analysis and Conclusion

WH4 runs smoother and produces more output when the draft tube air admission valve is closed at high output. This was successfully demonstrated during an assessment of vibration and cavitation issues in 2022. An alternative to installing an automated isolation value is to keep the valve open or closed all the time or operate seasonally. The disadvantage of this option is that substantial efficiency gains will be lost due to the need to send operational staff out each time to make manual adjustments.

The potential risk of not completing this project is cavitation damage to the WH4 Hydro Unit. Work is planned to be completed in 2024.

WG2 Cylinder Heads Swap	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
				$0.500 million

Overview

This project relates to the replacement of cylinder heads for the WG2 unit to address issues that have been experienced on an ongoing basis.

Analysis and Conclusion

Unit WG2 will reach the 20,000-hour mark in 2023 and an overhaul will be completed before end of 2023. A replacement of the cylinder heads is planned for 2024 following the overhaul work. The overhaul work will confirm the requirement for replacement to address identified issues with the cylinder heads.

WG1 Radiator Replacement	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
				$0.300 million

Overview

This project will investigate whether a permanent repair solution to the WG1 radiator is feasible or if replacement is required.

Analysis and Conclusion

After an unexpected failure, the radiator for the WG1 natural gas generator was repaired and put back into service. It was subsequently determined that the repair was not successful and there issues that need to be addressed to provide a permanent or more durable solution.

If the radiator were to suffer a complete failure, it would likely take up to six months to procure and install a replacement resulting in the WG1 unit being taken offline for the duration. This project will investigate whether a permanent repair solution is feasible or if a complete replacement is required, followed by the implementation of the chosen solution.

5.1B-2: TRANSMISSION PROJECTS

There was approximately $0.552 million added to rate base in 2021 on transmission projects $100,000 to $1 million; $0.012 million added in 2022; $0.480 million forecast to be added for 2023 test year; and $1.339 million forecast for the 2024 test year. Total 2024 rate base increase from these transmission projects approximates $3.009 million, excluding any depreciation or amortization deductions and before contributions of approximately $0.627 million. Rate base additions relate to the following projects:

- Transmission Line Access ($0.552 million in 2021);
- Alexco Mobile Substation Connection & Contributions ($0.193 million in 2021 with a $0.193 million contribution);
- 177 Re-Route ($0.012 million in 2022; and $0.738 million in 2023 with a $0.434 million contribution);
- NWTEL Make Ready Work ($0.175 million in 2023);
- P&C: S170 Protection, Control and SCADA Upgrade ($0.839 million in 2024);
- L177 Gang Switches ($0.250 million in 2024); and
- Transmission Line Test and Treat Program ($0.250 million in 2024).

Transmission Line Access	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
	$0.552 million			

Overview

YEC requires access to transmission lines for maintenance, inspection, and brushing activities. The project included the completion of a management plan for transmission access points including current condition, work and permits required, and estimated costs, specifically for accesses required to complete the Transmission Line Refurbishment project. It also included construction of new accesses and upgrades to existing accesses. Completion is expected to result in faster response times for emergency line work, avoidance of potential YG penalties and reliable access to key YEC assets.

Analysis and Conclusion

A number of temporary access points lacked the necessary permitting and were potentially not constructed to an acceptable standard. The Yukon government authority has indicated this situation is no longer acceptable and must be rectified. As such, there was no alternative to completing this work.

This project was reviewed during the 2021 GRA. The response to 2021 GRA YUB-YEC-2-17 noted that Scope for 2020 was revised as no accesses were required to be constructed. Updated costs provided during the 2021 GRA review were $541,900. Final costs in 2021 were $0.552 million.

In Order 2022-03 the Board indicated that the costs for this project were reasonable and directed YEC to include updated costs for any projects completed prior to or during the 2021 test period. The Board noted that costs would only be added to rate base once YEC provides the actual capital spending amount in the next GRA and demonstrates the costs were prudently incurred.

	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
Alexco Mobile Substation Connection & Contributions	$0.193 million ($0.193 million contribution)			

Overview

Alexco plans to use a 3 MVA, 69 kV/4.16 kV mobile self-contained substation to feed their Birmingham site at Keno.

The substation must be connected to the McQuesten-Keno 69 kV line. The project includes supply, installation and commissioning of the new line tap including connection to existing 69 KV line, engineering and commissioning support for the new mobile substation.

Analysis and Conclusion

YEC engaged Chimax to complete a 69 kV line tap design to connect the Alexco mobile substation to the McQuesten-Keno 69 kV line. Project costs were fully recovered from the customer.

Costs reviewed during the 2021 GRA were $0.178 million with an equal contribution. Final costs and contribution each were $0.193 million.

	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
177 Re-Route		$0.012 million	$0.738 million ($0.434 million contribution)	

Overview

Due to YG highway construction plans near transmission line L177, two sections of the line need to be relocated. Due to conditions of our existing permits, YEC is required to re-locate one of these sections of the line. YG is responsible for the costs to relocate the other section of line.

Analysis and Conclusion

YEC completed the work that YG is responsible for over the 2022 and 2023 construction season, with costs being fully offset by contributions.

The relocation work that YEC is responsible for is estimated to cost $316k and planned for completion in 2023, although there is some uncertainty if YG will proceed with it. As this is a permit requirement, there is no alternative option to complete this work or ability to defer it if YG chooses to proceed.

NWTEL Make Ready Work	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
			$0.175 million	

Overview

During 2023 Northwestel will be upgrading its telecommunications infrastructure in Mayo and Faro to fibre optic. This project is focused on replacing structures that are not compatible with the new technology.

Analysis and Conclusion

Based on a recent YEC assessment, a number of structures were identified that are not compatible with the new technology and need to be replaced.

There is no reasonable alternative to completing this project as YEC would lose existing communication functionality, removing the ability of the system operator to control equipment and view local information through SCADA.

P&C: S170 Protection, Control and SCADA Upgrade	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
				$0.839 million

Overview

S170 McIntyre Substation lies in the heart of the Whitehorse electrical grid. S170, along with S150, supply power at 34.5kV to most of the Whitehorse residential and commercial loads (excluding Whistlebend).

S170 is one of the last locations to still have old style Electro Mechanical (EM) relays in service. This upgrade project as well as multiple other protection, control and SCADA upgrades were identified in a 2020 SNC Lavalin asset management framework report. This work was also prioritized and driven by the asset management plan being implemented by YEC.

Analysis and Conclusion

The S170 EM relays are long past end of life and are challenging to properly service and maintain. Further, the substation remote terminal unit (Survalent XPPB) is no longer manufactured or supported.

If the McIntyre Substation fails, the result will be a widespread outage as about 1/3 of the City of Whitehorse is powered through S170. If S170 fails during the winter, the power distribution for Whitehorse could not be reconfigured to redistribute the load without overloading other equipment. There is no feasible alternative to proceeding with this work at this time.

The failure would also result in damaged electrical equipment which could be costly to fix.

Project cost estimates are based on similar work completed in recent years at other substations.

L177 Gang Switches	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
				$0.250 million

Overview

This project will install two gang switches (along with fault finders) on the transmission line, allowing crews to sectionalize the line and reduce the time required to locate and respond to faults.

Analysis and Conclusion

The L177 line between Stewart Crossing and Dawson has approximately 1,750 transmission structures which can make it difficult to locate a fault in a timely manner. As an example, during the winter of 2021-22 it took two full days to locate a fault during a cold snap. This resulted in over $100k of diesel costs while the town of Dawson was disconnected from the grid.

Transmission Line Test and Treat Program	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
				$0.250 million

Overview

YEC's Transmission Line Asset Monitoring regime consists of two programs: 'Detailed Inspection' and 'Test & Treat'. The Test and Treat program serves the dual purpose of providing an objective measure of remaining pole life and slowing decay through re-treatment as required.

Analysis and Conclusion

The program treats ant colonies with insecticide, treats poles with fumigant to slow decay, treats external damage with preservative, and performs internal inspection of the pole to measures shell thickness to assess the pole condition. Test and Treat field staff are expert in assessing the internal condition of wood poles and collecting required information for management of YEC's wood pole assets. Test and Treat is typically performed by a dedicated contractor specializing in this type of work.

The wood pole condition information collected through test and treat is used to plan pole replacements over all of YEC's wood pole transmission lines.

Without completing this program, YEC will lack the information required to plan transmission line repair work. Further, life expectancy of transmission poles will be significantly decreased due to lack of treatment and an increase in future O&M costs will occur to address failures on an emergency response basis. As such, there is no reasonable alternative to undertaking this work.

5.1B-3: DISTRIBUTION PROJECTS

There was approximately $0.097 million added to rate base (beyond amounts approved in the 2021 GRA) in 2021 on distribution projects $100,000 to $1 million; $0.078 million added in 2022, $0.237 million forecast to be added for 2023 test year; and $0.200 million forecast for the 2024 test year. Total 2024 rate base increase from these distribution projects approximates $9.642 million, excluding any depreciation or amortization deductions and before total contributions of approximately $9.031 million. Rate base additions relate to the following projects:

- Customer Extensions ($0.943 million in 2021 with a $0.846 million contribution; $0.201 million in 2022 with a $0.123 million contribution; $1.727 million in 2023 with a $1.261 million contribution; and $0.600 million in 2024 with a $0.400 million contribution);
- IPP Connections ($5.205 million in 2023 with a $6.401 million contribution);
- Synchronous Condenser Overhaul ($0.616 million in 2023); and
- Dawson Distribution 3 Phase Loop ($0.350 million in 2023).

	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
Customer Extensions	$0.943 million ($0.846 million contribution)	$0.201 million ($0.123 million contribution)	$1.727 million ($1.261 million contribution)	$0.600 million ($0.400 million contribution)

Yukon Energy is required to provide service to new customers connecting to the grid system. Customer extensions are forecast and budgeted as capital items without identifying specific projects. Most costs of customer extensions are covered by customer contributions pursuant to the Terms and Conditions of Service.

	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
IPP Connections			$5.205 million ($6.401 million contribution)	

Overview

The Standing Offer Program (SOP) provides opportunities for non-utilities (Independent Power Producers, IPPs) to provide new sources of renewable electricity that increase the supply of affordable, reliable, and clean electrical energy in Yukon. It encourages the development of new, small, and renewable energy projects by developers interconnecting into the Yukon Integrated System (YIS) or Watson Lake Grid (WLG). The implementation of the SOP contributes to Yukon Government's objective of generating 97% of Yukon's electricity using renewable sources by 2030, which was identified in *Our Clean Future* strategy.

The SOP is managed by Yukon Government and implemented by Yukon Energy (YEC) and ATCO Electric Yukon (AEY) (the Utilities). Depending on the geographic location of the project, it may connect to the WLG (entirely owned and operated by AEY), the YIS in a YEC distribution area (entirely owned and operated by YEC), or the YIS in an AEY distribution area.

Analysis and Conclusion

All utility costs for project planning and execution, up to COD and including dedicated capital project work such as post-commissioning, are the responsibility of IPP developers. All utility operation and maintenance costs associated with the projects once complete are the responsibility of the utilities, including among others ongoing network and communication costs for remote metering and SCADA connections. The Project Manager monitors costs related to commissioning and post-commissioning activities to ensure project capital costs as well as operation and maintenance costs are allocated appropriately. All utility costs chargeable to an IPP are to be paid by the developer in advance of completion of the work.

The table below summarizes information regarding currently connected and forecast IPP customers in 2023 and 2024.

	Capacity, MW	Expected In Service Date
Solvest/ North Klondike	1 MW	Nov-21
Nomad (Mount Sima)	0.150 MW	Jan-22
KDO Dawson Dome Road	0.200 MW	Mar-22
Sunergy 2 MW solar	2 MW	Jul-23
Arctic Pharm 2MW solar	2 MW	Aug-23
Haeckel Hill West 2 MW wind	2 MW	Oct-23
Haeckel Hill East 2 MW wind	2 MW	Oct-23
CTMC 2 MW Solar	2 MW	Sep-24
NNDC 2 MW Solar	2 MW	Dec-24
NNDC 2 MW Solar	2 MW	Dec-24
250 kW Solar	0.250 MW	Dec-24

Synchronous Condenser Overhaul	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
			$0.616 million	

Overview

The synchronous condenser in Callison serves two important purposes in the Dawson electrical system when connected to the grid:

- Maintains constant voltage in the town of Dawson by changing the reactive power requirements at Callison; and
- Under fault condition, it supplements the fault contribution from the grid to ensure that there will be enough fault current to correctly operate protection relays and fuses in the Dawson area.

This project will modernize the controls including a PLC for start up and auxiliary control, new voltage relay, a VFD for pony motor control, new unit protection relay and the install of an RTAC for Scada communications. Along with the increased reliability, the unit will also be able to be started remotely.

Analysis and Conclusion

The synchronous condenser protection and controls have reached end of life and are beginning to fail.

The unit has not operated reliably the last 3 years resulting in longer downtime of the unit due to failing controls and auxiliary system and diesel generation costs to support the Dawson system whenever the condenser is out of service. Further, each time L177 trips the condenser will trip as well, leading to a call out to manually start the unit. It is common for Dawson personnel to experience difficulties in getting the sync condenser back online and staff are often dispatched out of Whitehorse or Mayo to assist. The system controls need to be modernized to increase reliability and effectiveness.

Engineering and design work was completed by Taifa Engineering and occurred during 2022 and construction is planned for 2023.

Dawson Distribution 3 Phase Loop	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
			$0.350 million	

Overview

On December 23, 2022 a significant outage occurred in Dawson city, lasting almost 24 hours until full restoration was completed.

Several challenges occurred during the restoration process which included phase imbalance issues and the inability to shift load throughout the distribution system. Due to steady growth in Dawson, these issues are getting worse every year and outage restoration is becoming increasingly difficult.

This project involves the construction of a three phase loop between feeder 1 and 2 in the north end of Dawson.

Analysis and Conclusion

Construction of a three phase loop between feeder 1 and 2 will fix the phase imbalance issue that caused trouble with December restoration and also provide the ability to shift load between feeders as necessary. Additionally, four new gang switches will be added to Dawson feeders (two in the new 3 phase loop, one to replace an existing switch, and one added to feeder 2). This will provide major advantages for restoration purposes (increased ability to sectionalize the distribution network) and allow for a better response when only one PLT is in the district.

This work will also support the upcoming voltage conversion project as it will allow the distribution network to be broken into smaller sections, allowing increased flexibility in work planning and execution.

5.1B-4: GENERAL PLANT AND EQUIPMENT PROJECTS

There was approximately $0.412 million added to rate base (beyond amounts approved in the 2021 GRA) in 2021 on General Plant and Equipment projects $100,000 to $1 million; $0.573 million added in 2022; $2.068 million forecast to be added for 2023 test year; and $1.812 million forecast for the 2024 test year. Total 2024 rate base increase from these general plant and equipment projects approximates $4.865 million, excluding any depreciation or amortization deductions. Rate base additions relate to the following projects:

- Major Crane Asset Replacement/ Refurbishment ($0.293 million in 2021; and $0.700 million in 2024);
- Server Replacements ($0.119 million in 2021);
- Aishihik Bridge Re-decking ($0.109 million in 2022);
- Vehicle Purchases ($0.464 million in 2022; $0.624 million in 2023 and $0.567 million in 2024);
- New Mobile Office Unit – IT ($0.810 million in 2023);
- Compact Digger Truck ($0.200 million in 2023);
- Skid Steer ($0.189 million in 2023);
- Mayo-McQuesten Radio to Fiber Migration ($0.135 million in 2023);
- Waste Management Equipment ($0.110 million in 2023);
- HQ Datacentre Server Replacement ($0.300 million in 2024); and
- SCADA Operation Network Segregation ($0.245 million in 2024).

Major Crane Asset Replacement/ Refurbishment	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
	$0.293 million			$0.700 million

Overview

Cranes and hoists play a critical role in the daily operation and capital project execution at most of Yukon Energy's facilities (approximately 38 units in total). This project is focused on addressing identified deficiencies to ensure continued safe and reliable operation.

Analysis and Conclusion

Recent 3rd party assessments and inspections by Kone Cranes have identified deficiencies that present significant safety and operational risks if not addressed. 2024 spending will focus on the replacement of two end of life cranes in Mayo along with individual component replacement on various cranes based on the most recent inspection data from Kone Cranes.

Server Replacements	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
	$0.119 million			

Overview

Built in 2012, the datacenter in the WH0 hydro plant has been critical to keeping digital services running reliably. The existing servers were at end of life and required replacement with more modern equipment.

Analysis and Conclusion

This hardware hosts a plethora of virtual servers: mail, phone, reporting, user login, metering, video surveillance, firewalls, and security auditing tools. The existing servers were at end of life and no longer compatible with modern systems. The storage array was on extended support and reliability was starting to become an issue.

This project replaced the server and storage array with modern equipment to support reliable business services as well as the roll-out of the Enterprise Asset Management (EAM) software.

Aishihik Bridget Re-decking	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
		$0.109 million		

Overview

The Aishihik bridge was built in 2001 and consisted of steel foundation and wood decking. The wood decking is at end of life and needs to be replaced for safety purposes.

Analysis and Conclusion

During 2022 it was determined that the wood decking component of the bridge had reached end of life and needed to be replaced for safety reasons. The assessment also indicated that the steel foundation had many years left and did not need to be replaced with the replacement of the wood. The new wood should last between 20 and 30 years.

The option of not re-decking the bridge is not considered an option as there is no reasonable alternative route to get to the Aishihik generating station. YEC considered replacing the entire bridge, replacing the decking with wood and replacing the decking with steel.

It was determined that replacing the entire bridge was not necessary as the supporting steel frames were assessed and considered to be in good condition. YEC records indicate that there are 33 years life left on the steel. YEC decided the best option would be to replace the decking with wood as it is cheaper than replacing with steel, and the expected life of the wood is consistent with the expected life of the existing steel frame.

Re-decking of the bridge using wood was started and completed in 2022. A competitive bidding process was used and Mobile Maintenance Services was selected to perform the work. Costs to the contractor amounted to $106,305. The remaining $2,949 project costs were YEC internal costs.

Vehicle Purchases	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
		$0.464 million	$0.624 million	$0.567 million

Overview

Fleet vehicles are regularly replaced based on an annual analysis that considers vehicle age, mileage, condition, and maintenance costs. YUB-YEC-1-85 in the 2021 GRA proceeding provided 5-year replacement history information.

Analysis and Conclusion

The forecast amount for 2023 includes: the purchase of two ½-ton pickup trucks, one ¾-tonne truck with a service canopy, one 2-ton flat deck truck, and one 2-ton truck with service body. Vehicle purchases planned for 2024 include one ½-ton pickup truck, one 3/4-ton pickup truck, and three 1-ton trucks (two with service bodies).

New Mobile Office Unit - IT	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.810 million	

Overview

The existing IT trailer, located within the main Whitehorse compound, is experiencing increasing maintenance costs each year, has been deemed to be at end of life and must be replaced. This project replaces the existing IT trailer with a new, larger trailer.

Analysis and Conclusion

If the existing IT trailer is not replaced, major repairs will be required including new roofing, fascia replacement, and a solution to ongoing indoor air quality issues. The current trailer has five offices and a storage area. The replacement office trailer will be larger and include eight office spaces, helping to address a shortage of office space in the main office building.

The new office trailer was ordered in 2022 and is on site in 2023.

Compact Digger Truck	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.200 million	

Overview

In 2022, YEC purchased a compact digger truck for use in Dawson to substantially decrease risks for workers and ensure greater efficiency in day-to-day work, including providing improvements in outage response times. This project was included in the prior rate application as a 2021 addition to capital assets with a projected cost of $185k.[1] Supply chain challenges and price inflation during 2021 delayed the acquisition date to 2022 and the receipt of truck until 2023, and increased the cost by approximately $20k.

Analysis and Conclusion

Servicemen previously used an attachable bucket that goes on the side of the digger boom for many types of work from street light maintenance, service work, trouble call response, and new construction. The bucket is heavy and difficult to attach/detach. In a trouble call scenario this can also be time consuming and increase trouble call response time leading to frustration and potential unsafe working conditions.

Skid Steer	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.189 million	

Overview

The project relates to the purchase of a skid steer for regular snow removal to maintain access for projects and emergency work.

Analysis and Conclusion

YEC has many sites that require regular snow removal to maintain access for projects and emergency work. Prior to purchasing the skid steer, contractors were hired to complete this work which was expensive and occasionally unreliable (during periods of heavy snow, there is a significantly more demand for snow removal contractors and YEC may be a lower priority than other customers). The equipment is also used in the summer to complete distribution brushing activities.

[1] See YUB-YEC-1-81 from the 2021 GRA which provided further details regarding the justification for the digger truck; and options reviewed at that time (which included renting a bucket truck and continuing to operate in the same manner); and information received from vendors at that time.

By performing this work using internal labour and owned equipment, annual costs savings (estimated at $40k) over the expected life of seven years result in a net positive impact for ratepayers.

	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
Mayo-McQuesten Radio to Fiber Migration			$0.135 million	

Overview

This project will move remaining services still using radio link to the new fiber line installed between Mayo and McQuesten substations.

Analysis and Conclusion

As part of the Mayo-McQuesten transmission line project, an optical ground wire cable was installed between Mayo and McQuesten substations. The project scope was limited to the migration of L180 tele-protection and the Mayo Remedial Action Scheme (RAS) from the Northwestel radio link to the new YEC fiber. However, SCADA and telephone communication remained on the radio link provided by Northwestel at a monthly cost of $6,500. Moving remaining services still using the radio link to the new fiber line will increase reliability and reduce O&M costs.

The simple payback period for this project is less than two years.

	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
Waste Management Equipment			$0.110 million	

Overview

The project will install waste management equipment in Whitehorse and Faro.

Analysis and Conclusion

Waste management equipment is required in Whitehorse and Faro for proper containment of hazardous materials prior to them being disposed. Currently, hazardous waste is being stored using critical space where other equipment could be better placed, or it is stored without adequate secondary containment thus exposing the corporation to environmental risk. Containment will also be purchased for proper transportation of hazardous materials between YEC locations and to a regulated disposal facility. The equipment will be utilized for electrical materials, thermal operations waste, transmission & distribution out of service transformers, as well as IT e-waste.

HQ Datacentre Server Replacement	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
				$0.300 million

Overview

The project will replace the HQ datacentre server which is at end of life and no longer supported.

Analysis and Conclusion

The corporate server cluster that runs various YEC business critical systems (Enterprise Resource Planning, Enterprise Asset Management, Sharepoint, Email, etc.) is at end of life and no longer supported. As of February 2024, replacement components will no longer be available. This project will replace all required hardware to ensure the continuation of basic business functionality at YEC.

SCADA Operation Network Segregation	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
				$0.245 million

Overview

The project will complete work required to upgrade the existing SCADA network in Dawson, Faro and Whitehorse.

Analysis and Conclusion

The YEC Supervisory Control and Data Acquisition (SCADA) system is the backbone for the centralized control and operation of the Yukon electrical grid. The existing legacy system is 20 years old and needs to be properly segmented to provide better security, stability, and scalability. Certain locations have been upgraded over recent years; this project will complete the remainder of work to refresh the network configuration in Dawson, Faro, and Whitehorse.

The completion of this project will allow the implementation of future planned projects related to data backup.

5.1B-4: OVERHAULS

Actual overhauls costs exceeding $100,000 approximated $2.341 million in 2022; forecast overhaul costs exceeding $100,000 approximate $3.261 million in 2023 and $0.850 million in 2024. Total 2024 rate base increase from these overhauls approximates $6.452 million, excluding any depreciation or amortization deductions. Rate base additions relate to the following projects:

- AH2 Overhaul ($2.341 million in 2022);
- AH1 10 Year Overhaul ($2.461 million in 2023);
- WG1 Overhaul ($0.400 million in 2023);
- WG2 Overhaul ($0.400 million in 2023);
- WG3 Overhaul ($0.400 million in 2024); and
- DD4 Overhaul ($0.450 million in 2024).

AH2 Overhaul	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
		$2.341 million		

Overview

The Aishihik Hydro Plant (AH0) is located approximately 140 km North-West of Whitehorse and consists of three hydroelectric turbine generators. The AH0 plant was originally commissioned in 1974 with two vertical Francis style hydro units (AH1 and AH2) and an additional horizontal Francis hydro unit (AH3) was added in 2012. The project relates to a 10 year overhaul for the AH2 unit to ensure ongoing safe and reliable operation.

Analysis and Conclusion

YEC has completed a major overhaul of AH2 in 2022. AH1 and AH2 are vital year-round generation assets in YEC's fleet and have a nameplate capacity of 15 MW. The last major overhauls were performed in 2012 and 2013 on AH1 and AH2 respectively. Since that time, both units have developed several operating issues that must be resolved to ensure continued reliable operation. These issues include wicket gate stalling, turbine shaft seal leakage, cavitation, lift pump underperformance, and overheating. Although AH1 was scheduled to be overhauled first, management selected AH2 for overhaul in 2022 instead of AH1 as there were more serious operational issues restricting unit output and performance. The scope of both overhaul projects will include a full disassembly, inspection, replacement of all wear parts and correction of known operational issues. The units will then be re-assembled and aligned, per CEATI best practices, to ensure smooth operation and minimal unit wear over the next decade of operation. During the work, precise measurements are taken on elevations, diameters, alignment, and coupling details to allow for efficient planning of a future runner replacement project to increase unit output.

If these projects are not completed, the risk of an unplanned outage will continue to increase beyond an acceptable level. Further, the operational issues identified would continue to create challenges with running the unit efficiently and without the involvement of on-site personnel.

As such, there are no reasonable alternatives to completing this overhaul project.

AH1 10 Year Overhaul	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$2.461 million	

Overview

The Aishihik Hydro Plant (AH0) is located approximately 140 km North-West of Whitehorse and consists of three hydroelectric turbine generators. The AH0 plant was originally commissioned in 1974 with two vertical Francis style hydro units (AH1 and AH2) and an additional horizontal Francis hydro unit (AH3) was added in 2012. The project relates to a 10 year overhaul for the AH1 unit to ensure ongoing safe and reliable operation.

Analysis and Conclusion

YEC completed a major overhaul of AH2 in 2022 and is planning the same work for AH1 in 2023. Both hydro units are vital year-round generation assets in YEC’s fleet and have a nameplate capacity of 15 MW. The last major overhauls were performed in 2012 and 2013 on AH1 and AH2 respectively. Since that time, both units have developed several operating issues that must be resolved to ensure continued reliable operation. These issues include wicket gate stalling, turbine shaft seal leakage, cavitation, lift pump underperformance, and overheating. Although AH1 was scheduled to be overhauled first, management selected AH2 for overhaul in 2022 instead of AH1 as there were more serious operational issues restricting unit output and performance.

The scope of both overhaul projects will include a full disassembly, inspection, replacement of all wear parts and correction of known operational issues. The units will then be re-assembled and aligned, per CEATI best practices, to ensure smooth operation and minimal unit wear over the next decade of operation. During the work, precise measurements are taken on elevations, diameters, alignment, and coupling details to allow for efficient planning of a future runner replacement project to increase unit output.

If these projects are not completed, the risk of an unplanned outage will continue to increase beyond an acceptable level. Further, the operational issues identified would continue to create challenges with running the unit efficiently and without the involvement of on-site personnel.

As such, there are no reasonable alternatives to completing this overhaul project.

WG1 Overhaul	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
			$0.400 million	

Overview

Yukon Energy's three natural gas engines are maintained based on hourly run times according to the manufacturer's recommendation. Unit WG1 will reach the 20,000-hour mark in 2023 and an overhaul will need to be completed.

Analysis and Conclusion

A 20k overhaul will cost approximately $400k per engine and is performed by an external contractor with some assistance provided by YEC. The scope of this overhaul includes inspection, maintenance, or replacement of the engine cooling pump, transmission, starter, switchgear cabinets, gas quantity controller, cylinder heads, turbocharger, vibration damper, and mixture bypass valve. This is the second largest overhaul performed on these engines, exceeded only by the 30k overhaul (half of the 60k life of the engines). Yukon Energy depends on these gas engines to provide reliable generation when needed, especially during the winter.

Not performing this critical maintenance on the schedule recommended by the OEM would raise the risk of an unplanned equipment failure beyond an acceptable level. This work is required to ensure safe and reliable operation as such there is no alternative to proceeding with this work.

WG2 Overhaul	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
			$0.400 million	

Overview

Yukon Energy's three natural gas engines are maintained based on hourly run times according to the manufacturer's recommendation. Unit WG2 will reach the 20,000-hour mark in 2023 and an overhaul will need to be completed.

Analysis and Conclusion

A 20k overhaul will cost approximately $400k per engine and is performed by an external contractor with some assistance provided by YEC. The scope of this overhaul includes inspection, maintenance, or replacement of the engine cooling pump, transmission, starter, switchgear cabinets, gas quantity controller, cylinder heads, turbocharger, vibration damper, and mixture bypass valve. This is the second largest overhaul performed on these engines, exceeded only by the 30k overhaul (half of the 60k life of the engines). Yukon Energy depends on these gas engines to provide reliable generation when needed, especially during the winter. Not performing this critical maintenance on the schedule recommended by the OEM would raise the risk of an unplanned equipment failure beyond an acceptable level. This work is required to ensure safe and reliable operation as such there is no alternative to proceeding with this work.

WG 3 Overhaul	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
				$0.400 million

Overview

Yukon Energy's three natural gas engines are maintained based on hourly run times according to the manufacturer's recommendation. Unit WG3 will reach the 20,000-hour mark in 2024 and an overhaul will need to be completed.

Analysis and Conclusion

A 20k overhaul will cost approximately $400k per engine and is performed by an external contractor with some assistance provided by YEC. The scope of this overhaul includes inspection, maintenance, or replacement of the engine cooling pump, transmission, starter, switchgear cabinets, gas quantity controller, cylinder heads, turbocharger, vibration damper, and mixture bypass valve. This is the second largest overhaul performed on these engines, exceeded only by the 30k overhaul (half of the 60k life of the engines). Yukon Energy depends on these gas engines to provide reliable generation when needed, especially during the winter. Not performing this critical maintenance on the schedule recommended by the OEM would raise the risk of an unplanned equipment failure beyond an acceptable level. This work is required to ensure safe and reliable operation as such there is no alternative to proceeding with this work.

DD4 Overhaul	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
				$0.450 million

Overview

This project relates to a completing a recommended 24,000 hour overhaul of DD4 unit.

Analysis and Conclusion

In response to ongoing unit shutdowns due to high oil temperature, a 3rd party contractor (Collicutt Energy) was commissioned to complete and assessment of Dawson diesel unit DD4. The resulting report recommendations included the completion of a 24,000 hour overhaul as soon as possible. If this work is delayed beyond 2024, the risk of unplanned failure will likely exceed acceptable limits. This work is required to ensure safe and reliable operation as such there is no alternative to proceeding with this work.

5.1B-5: RIGHT OF USE ASSETS

Actual right of use assets costs exceeding $100,000 approximated $1.181 million in 2022; forecast right of use assets costs exceeding $100,000 approximate $0.750 million in 2023. Total 2024 rate base increase from these right of use assets costs approximates $1.931 million, excluding any depreciation or amortization deductions. Rate base additions relate to the following projects:

- Right of Use Asset Battery Land Lease ($1.004 million in 2022);
- Right of Use Asset Kulan Land ($0.177 million in 2022); and
- Right of Use Asset 1 Lindeman Road ($0.750 million in 2023).

Right of Use Asset Battery Land Lease	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
		$1.004 million		

Overview

The Battery Energy Storage System (BESS) was identified as a key project in both the 2016 Resource Plan and the 10 year Renewable Electricity Plan to provide dependable capacity. It was recognized at inception that additional land would be required to site this new asset. This project relates to the long-term lease of property for the BESS project.

Analysis and Conclusion

Three potential project locations were identified for the BESS based on their proximity to YEC's existing grid infrastructure in the Whitehorse area. All three potential sites were located on undeveloped First Nation Category B settlement land. One site belonged to the Ta'an Kwäch'än Council (TKC) located near the City of Whitehorse snow dump off Robert Service Drive, and two sites belonged to Kwanlin Dün First Nation (KDFN) - one site near the intersection of Robert Service Drive and the Alaska Highway, and the second site adjacent to YEC's Takhini Substation on the North Klondike Highway.

During 2020, YEC formed a trilateral Project Committee with TKC and KDFN with a mandate to share information, make a recommendation regarding final site selection. This process assessed potential sites against a number of objectives:

• Maximum technical benefits;

• Minimize costs;

• Minimize social risk;

• Minimize development/operating risk; and

• Provide certainty to execution.

Each site option provides a variety of benefits and limitations. For the majority of the detailed evaluation criteria, the three potential sites offered relatively equivalent benefits and costs. These evaluation criteria were screened out in order to inform the site decision based on the main differences between the sites. A summary of the site evaluation, with the key differentiating evaluation criteria and analysis of each site's attributes is presented below.

Criteria	TKC: Robert Service Way	KDFN: Alaska Hwy & South Access Road	KDFN: Mayo Road (North Klondike Hwy)
Ability to Provide Services	All Services	All Services	Most Services
Total 25 year Lease Cost (NPV)	$1,386,085	$956,601 (-45%)	No Offer
Lease Benefits Sharing	No	Yes	N/A
Certainty to Development	High	Moderate	N/A
Operating Cost Impact: Taxes	City Taxes	City Taxes	Outside City Limits
Operating Cost Impact: Proximity to YEC	Low Impact	Low Impact	Moderate Impact
Social License	Moderate	Moderate	High Risk

In November 2020, Management recommended eliminating the latter KDFN site from consideration given the results of the public engagement process, as well as the technical uncertainties and operational limitations given the distance from YEC's Whitehorse Rapids facility.

YEC received commercial offers from the Project Committee representatives for the TKC site and the KDFN site within Whitehorse city limits. KDFN's site offer was more favourable in terms of total lease costs and certainty to development, and it included consideration of a mechanism to share the benefits of the lease with TKC.

In December 2020, it was determined to proceed with the KDFN-owned site at the Northeast corner of the Alaska Highway and Robert Service Way.

In January 2022, YEC and Da Nan Developments Ltd. finalized a sublease agreement for the KDFN-owned site at the Northeast corner of the Alaska Highway and Robert Service Way. The term of the lease commenced on April 1, 2022 and terminates March 31, 2047. The lease agreement required payment upfront for the entire lease period. Due to the time between the proposal process and the finalization of the lease agreement, the net present value of the lease cost changed from $956,601 to $968,751 (due to market fluctuations of discount rates). In addition to the lease payment, YEC was required to pay $35,000 for the lessor's reasonable costs incurred in clearing and preparing the land. As a result, the total cost capitalized was $1,003,751.

Right of Use Asset Kulan Land	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
		$0.177 million		

Overview

YEC has been leasing land at Kulan adjacent to the YEC Warehouse since August 2017. The property is used for additional storage of inventory and spare parts as an extension of the YEC owned warehouse property. The five-year lease expired August 31, 2022. YEC is growing and expects to require this (or similar) space for at least the next several years. This project relates to leasing the property for a 5-year term.

Analysis and Conclusion

YEC is investigating alternatives such as consolidating property at the location of the KDFN owned Battery site closer to head office. However, significant analysis needs to be done, and if the decision is made, construction will take time. The location of this site is preferential in the short-term (until consolidation analysis determines otherwise) as it is located adjacent to YEC's Kulan property that houses the Warehouse, as well as the primary user of this property, the T&D group, that is located adjacent at 1 Lindeman Road. Therefore, YEC decided that it had to stay at this location at the current time. Negotiations with the property owner resulted in annual costs of $39,000 (total of $195,765) for the 5-year lease.

The price increase of 4% is reasonable in light of current inflation and interest rates. The Capital cost of the lease represents the present value of lease payments. International Financial Reporting Standards require these lease payments to be capitalized rather than expensed as payments are made.

Right of Use Asset 1 Lindeman Road	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
			$0.750 million	

Overview

YEC has been leasing property and office space at 1 Lindeman Road since October 2018. The property houses YEC's PLT employees, the PLT shop, Records and additional storage. The five-year lease expires September 30, 2023. YEC is growing and expects to require this (or similar) space for at least the next several years. This project relates to leasing this property for a five-year term.

Analysis and Conclusion

YEC performed enquiries but was not able to find alternative ready for use sites. YEC is investigating alternatives such as consolidating property at the location of the KDFN owned Battery site which is closer to head office. However, significant analysis needs to be done, and if the decision is made, construction will take time. The location of this site is preferential in the short-term (until consolidation analysis determines otherwise) as it is located adjacent to YEC's Kulan property that houses the Warehouse. Therefore, YEC decided that it had to stay at this location at the current time. YEC investigated options of the standard 5-year lease as well as a shorter 3-year lease.

YEC investigated options of the standard 5-year lease as well as a shorter 3-year lease. Negotiations with the property owner resulted in pricing options of annual costs of $174,600 (total of $873,000) for the 5-year lease and annual costs of $201,600 (total of $604,800) for the 3-year lease. Discussions within YEC determined that it may be difficult for YEC to have another option available within 3 years for YEC to relocate. Therefore, based on a lower annualized cost and the decision that YEC would likely require the property closer to 5 years, it was decided to enter into a 5-year lease.

Justification for the price is based on the fact that the rent has been held constant for the prior 5 years, and there was significant inflation and an increase in commercial property values over this period. Built into the new lease are modest annual increases in light of current inflation and interest rates. The capital cost of the lease represents the present value of lease payments.

International Financial Reporting Standards require these lease payments to be capitalized rather than expensed as payments are made.

5.1B-4: RFID

	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
RFID	$1,393 million	$7.816 million ($5.899 million contribution)	$0.899 million	$0.682 million

Background

The RFID is an account maintained as approved by the Board 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.

Analysis and Conclusion

As reviewed in section 3.3.7 of Tab 3 of this Application, the large expense in 2022 primarily reflects costs associated with the Whitehorse penstock failure ($6.501 million, and $5.899 million insurance claim offset), LNG gearbox failure, Dawson diesel coupling failure, flood mitigation and the Mayo rock slope failure.

For the 2023 test year, YEC is forecasting annual costs of $0.899 million (this includes $0.554 million spending in 2023 and $0.346 million WIP from 2022) and for 2024 annual cost of $0.682 million.

5.1B-5: RESERVE FOR SITE RESTORATION

	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
Reserve for Site Restoration			$0.763 million	

Background

Yukon Energy maintains a provision for future removal and site restoration costs related to property, plant and equipment. Order 2005-12 provides that this reserve is not to exceed the cumulative value of the provision at December 31, 2004 of $5.757 million, and that YEC is to notify intervenors and interested parties when the balance of the provision declines to $2.0 million. By the end of 2023, the balance is expected to decline slightly below the $2.0 million indicated by the YUB. YEC is not proposing any changes for the test years.

Analysis and Conclusion

The costs in 2023 (includes $0.723 million spending in 2023, the rest relates to WIP) are primarily for final site restoration costs at Haeckel Hill where YEC previously had wind generation assets.

APPENDIX 5.2A
DEFERRED PROJECTS >$1 MILLION ADDED TO RATE BASE

APPENDIX 5.2A: DEFERRED PROJECTS >$1 MILLION ADDED TO RATE BASE

Appendix 5.2A summarizes deferred projects over $1 million that will be added to rate base in the test years.

Test year spending on major deferred cost projects focuses 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 future potential generation and transmission requirements.

Total forecast to be added to net rate base for major deferred cost projects by the end of 2024 is approximately $16.037 million. Each major project added to rate base is reviewed separately below (see also Tables 5.2 to 5.6 at the end of Tab 5):

- **Spending on Sustaining Capital** – Net rate base impact of approximately $4.479 million, excluding reductions due to amortization:
    - **Aishihik Relicensing (Five-Year Licence Renewal)** - $4.479 million net increase in rate base by the end of 2023, excluding reductions due to amortization.
- **Spending on planning to meet other future Generation and Transmission Requirements** – Net rate base impact of approximately $11.558 million by the end of 2024, excluding reductions due to amortizations:
    - **Demand Side (DSM) Program Development and DSM Program 2022-2030** – $2.774 million net increase in rate base by the end of 2024, after contributions but excluding reductions due to amortization.
    - **Southern Lakes Storage –** $8.784 million net increase in rate base by the end of 2023.

Business case summaries for major deferred cost projects added to rate base in this GRA are reviewed below.

SECTION 5.2A-1: AISHIHIK GENERATING STATION FIVE-YEAR LICENCE RENEWAL (ADDITIONS TO RATE BASE OF $3.903 MILLION IN 2022 AND $0.575 MILLION IN 2023)

This deferred project provided a five-year renewal of YEC's Aishihik Generating Station ("AGS") water use licence, and work towards the same for the AGS Fisheries Act Authorization ("FAA"), from January 1, 2023 until December 31, 2027.

Background

The AGS provides the only multi-year hydro storage and the largest winter peak hydro generation capability on the Yukon Integrated System ("YIS"). Renewal of the water use licence, and renewal of Department of Fisheries and Oceans ("DFO") FAA, are both required to authorize YEC to regulate the water levels at, and flows from, Aishihik and Canyon Lakes for the purpose of generating electricity at the AGS.

The previous AGS long-term licence and FAA in place since 2002 expired on December 31, 2019. Starting in 2016 Yukon Energy commenced processes to undertake the required engagement and assessments needed to ensure renewal authorizations would be in place for the facility to continue to operate. With efforts to collaboratively plan the renewal with both the Champagne and Aishihik First Nations and Yukon Government taking longer than anticipated, Yukon Energy initially applied for a 3-year renewal in 2019 in order to ensure the facility authorizations did not expire and to allow time to complete a long-term renewal process.

Yukon Energy was issued a renewed water use licence [Licence HY19-016] for the AGS on February 19, 2020 for a 3-year term ending December 31, 2022[1]; the FAA was similarly renewed for three years. Yukon Energy then commenced preparation of a new project proposal under the *Yukon Environmental and Socio-Economic Assessment Act* ("YESAA") to support a long term renewal of the authorizations for the AGS facility.

Process leading to 5-Year Renewal

Following a multi-party planning process, Yukon Energy submitted a YESAA Project Proposal for a 25-year licence renewal to the Haines Junction Designated Office (DO) of the Yukon Environmental and Socio-Economic Assessment Board (YESAB) on July 10, 2020. An application for a 25-year licence renewal was subsequently filed with the Yukon Water Board (YWB) on May 31, 2021.

The Designated Office Evaluation Report was issued on June 18, 2021. In that report, the Haines Junction Designated Office declined to assess the proposed licence renewal for the 25-year period requested by Yukon

[1] The three year licence renewal was granted as a renewal of Water Use Licence HY19-057, a 60-day renewal of Water Use Licence HY99-011 (issued 2002) which was a long term renewal of the original Water Use Licence Y3L5-0307 issued in 1978 and amended in 1991.

Energy, and instead decided to confine the temporal scope of the assessment to 5 years. A Decision Document for a 5-year renewal term was subsequently issued on October 21, 2021 by the Government of Yukon and Fisheries and Oceans Canada. As a result of these regulatory decisions, the YWB's jurisdiction to renew the AGS water licence was confined to the 5-year period assessed by the Designated Office, from January 1, 2023 to December 31, 2027 (pursuant to section 86 of YESAA), and Yukon Energy had no feasible option other than to revise its Water Use Licence Renewal application to be limited to that 5-year period.

Summary of Costs for Five-Year renewal

The AGS Water Use Licence renewal project and related costs as then forecast were initially reviewed as part of the 2017/18 GRA and the 2021 GRA. Updates regarding work completed and project costs for the long-term licence were reviewed in detail in YUB-YEC-1-90 filed during the 2021 GRA. YEC costs of $916,872 for the three-year licence renewal were reviewed and approved by the YUB during the 2021 GRA.

Specific costs allocated to the 5-year licence renewal are outlined in the table below:[2]

Stakeholder Engagement	448,963
Permitting	1,188,979
Monitoring	512,567
Compensation	618,842
Impact Assessment	1,303,338
Project Management	406,097
Total	**4,478,787**

- **Stakeholder Engagement** costs relate to funding the Champagne and Aishihik Community Advisory Committee (CACAC); negotiation costs to reach an agreement with the CAFN and Yukon Government relating to the AGS; capacity funding to CAFN to support participation in the project technical review and development of the Monitoring and Adaptive Management Plan; and public engagement activities.

  YEC deemed it prudent to engage the CAFN at the beginning of the current water use licence renewal process, given that the facility is located within the CAFN's traditional territory and the First Nation had significant historic grievances with the project. The objective of engagement was to increase participation by the CAFN in the water use relicensing regulatory process, increasing collaboration between YEC and CAFN, with a view to reducing the risk of conflict and/or adversarial legal action during the formal

[2] Table 5.7 (WIP schedule for projects not impacting rate base) shows $7.160 million of costs incurred from 2022 through forecast 2024 regarding AGS licence renewal that have been allocated to Aishihik 25-Year Licence renewal. Incurred costs allocated to the 5-Year AGS licence renewal address costs specific to the 5-year regulatory review processes. This includes project management, mitigation and monitoring costs, and assessment and permitting costs incurred over the 2020-22 period to prepare the regulatory documents that supported the 5-year renewal. Five-year renewal costs also include a share of impact assessment, monitoring, stakeholder engagement and consultation and other costs incurred over 2015-2018 to support a 25-year water use licence renewal. While the bulk of these foundational costs (roughly 75% in most cases) were considered incurred towards, and allocated to, the 25-year licence renewal, a portion of these costs were considered attributable to the 3-year and 5-year renewal processes.

regulatory proceedings, and finding mutually agreeable resolutions to matters of interest to each party that would satisfy the requirements of the YESAA Decision Document and avoid the risk of the AGS water licence renewal potentially being delayed or denied by the YWB.

- **Permitting** process costs are required to complete the regulatory activities which are mandatory to achieve the primary objective of the project (i.e., obtaining a water use license for the facility). They include: 1) the project proposal to YESAB's Haines Junction Designated Office; 2) regulatory application to the DFO; and 3) regulatory application to the YWB.

- **Monitoring costs** are related to early monitoring carried out to address issues relevant to CAFN, YESAB and regulators (including requirements from 3-year licence).

- **Compensation** costs relate to compensation to the CAFN and affected water users for the water use licence renewal, in accordance with the requirements of the Yukon *Waters Act*.

- **Impact Assessment** studies costs are related to the planning and execution of the environmental and social impact assessment studies in preparation for and respond to information requests related to the YESAB and YWB applications. These costs are required to be able to prepare the Project Proposal for the YESAB Designated Office and develop a Monitoring & Adaptive Management Plan for the YWB application, as well as costs associated with data collection and analysis during the assessment and permitting phases.

- **Project management** costs are primarily YEC internal costs related to work on planning and executing the project. These costs are required to move the project forward and coordinate the various working groups and deliverables.

The YESAA Designated Office review was completed in 2021 with issuance of the YESAA Evaluation Report on June 18, 2021. The Decision Document was issued on October 21, 2021. The YWB conducted a public hearing on the five-year of the AGS water licence in Haines Junction on November 21 and 22, 2022, and, following the hearing, the five-year water use licence renewal required to operate the project until December 31, 2027 was issued by the YWB on December 21, 2022, with the Yukon Government's approval. A one-year FAA extension was also issued on December 21, 2022, on the basis that additional time was needed for DFO to carry out its review under its current regulations.

Renewal of the AGS water use licence under terms substantially similar to the 2002 water use licence has been (and continues to be) considered the only reasonable option for Yukon Energy to pursue at this time given the following considerations:

- The AGS is a critical asset for the YIS; and ensuring that the regulatory instruments required for its ongoing operation are sustained is an essential requirement and responsibility for Yukon Energy.

- The AGS provides the only material annual hydro storage in the Yukon and load following power, after non-dispatchable generation resources (e.g., any existing wind or run-of-river hydro generation facilities) have been utilized.

- Under long-term average water conditions, the AGS supplies approximately 25% of the total annual YIS generation – and about 40% of annual YIS winter generation concentrated in the months from November through May when peak YIS loads occur and run-of-river hydro supplies are constrained.

- The AGS also provides 37 MW of dependable capacity[3] to the YIS, which is more than one quarter of Yukon Energy's maximum dependable generation capacity.

- Cessation or reduction of AGS operation would require that the current generation capability of AGS be replaced with some other source of energy that could be relied upon during the winter months. No such renewable alternative is in place today.

- Prior to planning, permitting and development of any new alternative generation capability, including renewable supply options, YEC would need to rely on existing thermal generation to replace the energy supplied currently by the AGS. Reliance on thermal generation to replace AGS hydro generation would have ongoing and very significant added generation operation costs (for fuel and non-fuel O&M) as well as environmental impacts associated with air pollutant emissions and added GHG emissions.[4]

- Yukon Energy currently maintains dependable capacity (relying on thermal generation capacity, including rented diesel units) as required for the N-1 event when AGS generation is not available; however, absent the AGS, material new thermal energy generation would be required on a long-term average basis. A significantly higher capital cost than $100 million would be required for similar new dependable renewable capacity even if such an alternative was available in the near to medium term.

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[3] Dependable capacity, expressed in MW, is the maximum generation output that a resource can reliably provide in a specific timeframe, typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on the inflows in the five driest inflow years in history.

[4] Implications are discussed at a high level in Appendix 6C of YEC's 2020 YESAB Project Proposal, which provides estimates of added capital and O&M costs as well as added GHG emissions associated with an alternative (Alternative 7) that removes AGS storage capability as proposed by CAFN and limits operating to the pre AGS Aishihik Lake LSL and FSL levels, i.e., the high added capital costs (+$100 million), O&M costs (~$12 million per year long-term average for thermal generation) and GHG emissions (+32 kt/year CO_2e long term average) for this alternative compared with the existing licence under 2021 grid loads and grid configuration which still retains run-of-river hydro generation benefits from the AGS.

Approximately $3.903 million was closed and added to rate base in 2022, and $0.575 million was closed and added to rate base in 2023. This total amount of approximately $4.479 million will be amortized over the licence term.

SECTION 5.2A-2: DEMAND SIDE MANAGEMENT (DSM) PROGRAM DEVELOPMENT AND DSM PROGRAM 2022-2030 (ADDITIONS TO RATE BASE [NET OF CONTRIBUTIONS] OF $0.010 MILLION IN 2021, $0.353 MILLION IN 2022, $1.250 MILLION IN 2023, AND $1.160 MILLION IN 2024)

1.0 BACKGROUND

Yukon Energy Corporation (Yukon Energy) is regulated, and commits significant resources, to meet Yukon's winter peak electrical demand. Yukon Energy has been developing a new portfolio of demand-side management (DSM) programs (DSM Portfolio) which offsets demand during peak times and provides the utility with dependable capacity, mitigating Yukon Energy's rapidly rising peak demand. Yukon Energy, in the planning and implementation of its DSM programs, has met all requirements for costs incurred by public utilities in the Yukon by participating in or providing DSM programs, in order for costs to be recovered through rates stipulated in OIC 2021-16.

The context within which Yukon Energy has approached DSM since 2021 is outlined by the following summary from the Yukon Utilities Board (YUB) Order 2022-03 (paragraph 305):

> The Government of Yukon issued OIC 2021/16 on February 11, 2021, which added sections to the Rate Policy Directive (1995) for the recovery of costs for DSM programs. The result of this OIC is that "demand-side management programs" are now defined in Subsection 10(1) of the Rate Policy Directive (1995) as "a measure, action or program intended to promote customer use of electricity that optimizes economy or efficiency of electricity generation or transmission of a public utility, including the promotion of customer use of electricity that (a) is more efficient, or (b) better aligns electricity supply and demand." Because of the OIC, the Board must include in rates for retail customers and major industrial customers the costs the public utility reasonably incurs to provide or participate in a DSM program (Subsection 10(2)). Pursuant to Subsection 10(3), the Board must consider the extent of any duplication between the DSM program for which costs are incurred and a DSM program provided by the Government of Yukon or in which the Government of Yukon is a participant. Subsection 10(4) set out the OIC's retroactive application to YEC's 2021 GRA that had already been filed with the Board when the OIC was issued.

The Yukon Government's Climate Change policy initiative called "Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy" emphasizes the importance of DSM as a valuable resource to reduce the Yukon's energy and capacity requirements. As part of that policy, the government fully expects Yukon Energy to pursue a cost-effective DSM program. The Yukon government issued OIC 2021/16 in 2021 to support utility-led DSM initiatives that met specified requirements.

Pursuant to the Government's expectations as presented in this policy initiative and OIC 2021/16, and further given DSM remains a cost-effective means of reducing energy and capacity requirements, Yukon Energy has included in the 2023/2024 GRA rate base the expenditures for the programs and activities as reviewed below.

1.1 DSM Program Development

DSM Program Development cost additions to test year rate base consist of costs to refine and update DSM program design, and to carry out a DSM Residential Demand Response Pilot.

In the 2017/18 General Rate Application, Yukon Energy noted plans to use end-use survey data, the results of a Capacity DSM Feasibility Study, and an updated CPR model to design a suite of new DSM programs to complement the existing inCharge program. Preliminary reports were completed in early 2019. In subsequent years, additional work was completed to refine and update program design, including implementation plans and forecasted cost-effectiveness metrics for each program. Yukon Energy is targeting programs that deliver a capacity benefit to address the dependable capacity shortfall.

The 2017/18 GRA also noted that new pilot program development would include consideration of capacity focused DSM programs such as demand response.

The Yukon Government's recent Climate Change policy initiative called "Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy" also provides the following policy directions regarding utility pursuit of capacity DSM:

- Provide direction to the Yukon Utilities Board in 2020 to allow Yukon's public utilities to partner with the Government of Yukon to pursue cost-effective demand-side management measures.

- EMR and YEC establish a partnership between the Government of Yukon, Yukon Energy Corporation and ATCO Electric Yukon by 2021 that will collaborate on the delivery of energy and capacity demand-side management programs.

- YEC complete the Peak Smart pilot project by 2022 to evaluate the use of smart devices to shift energy demand to off-peak hours.

Yukon Energy faces a capacity shortage under the single contingency (N-1) planning criterion. With this capacity planning context, and mindful of the policy context outlined in the Yukon Government's Climate change strategy, Yukon Energy pursued a pilot program testing internet connected, Wi-Fi enabled demand response technology designed to control residential baseboard and hot water heating during winter peak periods to help reduce system peak and reduce reliance on thermal generation such as diesel or natural gas.

The objective of the pilot program was to: evaluate the technical feasibility of the demand response technology; model and test the peak shifting effect of the pilot, test the reliability of the peak shifting effects of the pilot, and evaluate customer acceptance of the demand response events. Despite challenges that arose from the COVID-19 pandemic and the pilot program's technology vendor, the pilot program clearly demonstrated strong public interest and customer acceptance for demand response programs. The pilot program's demand reduction results, complimented by results from similar programs across the country, confirmed the technical feasibility of reducing peak demand with demand response technologies. The pilot program concluded in 2022, with all resulting recommendations incorporated into Yukon Energy's new DSM portfolio.

The project was managed by Yukon Energy with funding support from Atco Electric Yukon (AEY), Yukon Development Corporation (YDC) and Natural Resources Canada (NRCan).

The total expenditures for the above noted activities by the end of 2022 at $1.431 million are to be included in rate base in 2022, offset by contributions of $1.142 million, and are amortized over 10 years.

1.2 DSM Program 2022-2030

Yukon Energy has developed a new DSM portfolio that is: pursuant to policy directions provided in the Yukon Government's Climate Change policy initiatives (outlined above), aimed at mitigating Yukon Energy's growing capacity shortage under the single contingency (N-1) planning criteria, and building upon the successes and lessons learned from the DSM Residential Demand Response Pilot. The portfolio will be implemented in a phased approach, with the first program launching in Fall 2023.

The portfolio's target is to provide at least 7 MW of dependable capacity by 2030, with direct utility control of participating thermostats, hot water tanks, EV chargers, and other major loads across residential, commercial, and institutional sectors. Additional utility benefits of demand-response technologies, including cold-load pickup which supports reduced blackout recovery times, are also being pursued.

In Appendix A of Board Order 2014-06, the Board expressed concern regarding the equity of utility-led DSM initiatives, particularly regarding the barriers that may prevent low-income households from participating and therefore benefiting from the initiatives. Efforts to support the participation of low-income households are under development to address this concern. This includes developing a partnership with the Yukon Housing Corporation and working to minimize barriers to participate in each program's participant journey. Rental households and households living in Yukon First Nation housing have also been identified as potentially facing barriers to participate. Yukon Energy is also working to address these barriers through its upcoming DSM programs.

Overall, Yukon Energy's new DSM Portfolio is a cost-effective means of better aligning supply and demand, primarily by mitigating the Yukon Integrated System's rapidly rising peak demand. The cost-effectiveness of each program in Yukon Energy's new DSM Portfolio is addressed in detail below (Detailed DSM Program 2022-2030 Business Plan), along with a description of how the programs will be evaluated and how they optimize economic and efficient electricity generation.

The project is being managed by Yukon Energy. Contributions are being sought from both the federal and territorial governments.

Project expenditures of $2.475 million ($0.064 million in 2022, $1.250 million in 2023 (after $0.022 million contributions), and $1.160 million in 2024) are forecast to be included in rate base, offset by any future contributions secured through ongoing efforts, amortized over 10 years.

2.0 DETAILED DSM PROGRAM 2022-2030 BUSINESS PLAN

The business plan for the DSM Program 2022-2030 provides an overview of Yukon Energy's DSM Portfolio and addresses the OIC requirements for this work to be eligible and justified for inclusion in Yukon Energy's approved revenue requirements for the 2023/2024 GRA.

2.1 DSM Portfolio Overview

Yukon Energy's DSM Portfolio consists of three phases. Phase 1 is currently being implemented whereas Phases 2 and 3 are still in the planning stage.

1) Phase 1: Fall 2022 to Fall 2024

    - Residential Demand Response: This program seeks to reduce the peak load contribution from space and water heating. It consists of a direct-install initiative wherein participants receive internet-connected hot water tank controllers and/or thermostats, managed by Yukon Energy through a demand-response management system.

2) Phase 2: Fall 2024 to Fall 2025
   - Residential Demand Response: This program will transition from a direct-install initiative to a "bring-your-own-device" program in Fall 2024, with annual incentives offered to participants by YEC.
   - Dual Fuel Demand Management: This program seeks to avoid the use of resistance heating as a backup heat source to air-source heat pumps at extreme cold temperatures. It consists of a direct-install initiative targeting Yukon homes with both air-source heat pumps and fossil-fuel heating systems. Participants receive internet-connected thermostats (provided, configured, and managed by Yukon Energy) to automatically switch from the heat pump to the fuel-burning system when the outdoor air temperature drops below a threshold.
3) Phase 3: Fall 2025 through 2030
   - Residential Demand Response & Dual Fuel Demand Management Programs: These programs will continue on a "bring-your-own-device" basis, with annual incentives offered to participants by Yukon Energy, to consistently provide dependable capacity through 2030 and beyond.
   - EV Charging Demand Response: This program seeks to mitigate the peak demand contributions from electric vehicle charging. Yukoners with Level 2 electric vehicle chargers will be incentivized to enroll and participate in this "bring-your-own-device" demand-response program.
   - Commercial Demand Response: Through this program, Yukon Energy seeks to work with local commercial and institutional entities to reduce their contributions to peak demand and otherwise support grid stability. Solutions will be identified collaboratively and incentivized by Yukon Energy.

2.2 OIC 2021-16 Requirements

Order-in-Council (OIC) 2021-16 was issued in 2021 to, in part, support utility-led DSM programs in the Yukon, as per Action H26 from the Government of Yukon's Our Clean Future. The OIC includes three requirements for costs incurred by public utilities in the Yukon by participating in or providing DSM programs, in order for costs to be recovered through rates:

1) **Meet the definition of "demand-side management program":** "a measure, action, or program intended to promote customer use of electricity that optimizes economy or efficiency of electricity generation or transmission by a public utility, including through the promotion of customer use of electricity that (a) is more efficient, or (b) better aligns electricity supply and demand." (OIC 2021-16, Section 10(1)),

2) **Costs must be "reasonably incurred":** "The Board must include in the rates of a public utility for retail customers and major industrial customers provision to recover costs the public utility reasonably incurs to provide or participate in a demand-side management program." (OIC 2021-16, Section 10(2)), and

3) **Not be in duplication of DSM programs participated in or provided by another Yukon public utility or the Yukon Government:** "In determining whether costs are reasonably incurred by a public utility to provide or participate in a demand-side management program, the Board must consider the extent of any duplication between the program for which costs are incurred and a demand-side management program provided by the Government of Yukon in which the Government of Yukon is a participant." (OIC 2021-16, Section 10(3)).

Each of the above requirements set out in OIC 2021-16 is addressed below.

2.2.1 OIC 2021-16 Requirement #1 – Meet the Definition of "Demand-Side Management Program"

A "demand-side management program" is defined in OIC 2021-16 as the following:

> "a measure, action, or program intended to promote customer use of electricity that optimizes economy or efficiency of electricity generation or transmission by a public utility, including through the promotion of customer use of electricity that (a) is more efficient, or (b) better aligns electricity supply and demand." (OIC 2021-16, Section 10(1))

Yukon Energy's DSM Portfolio directly promotes customer use of electricity that optimizes the economy and efficiency of electricity generation and transmission by a public utility, including through the promotion of customer use of electricity that better aligns with electricity supply and demand, with energy efficiency improvements a secondary benefit from some programs.

1) <u>Direct customer participation:</u>

Yukon Energy's DSM programs will be open to all utility customers connected to the Yukon Integrated System, offering upfront incentives to encourage customers to enroll and participate (e.g. direct-install programs, wherein devices with features benefiting the participant are installed at the cost of the program administrator) and/or on-going incentives (e.g. on-bill credits for participation in Yukon Energy's demand-response programs).

Yukon Energy has also carefully considered the barriers to participate in utility-led DSM programs that some Yukoners, such as low-income households, may face. Efforts are ongoing to mitigate any such barriers. For more information on Yukon Energy's DSM program equity initiatives, see further discussion below.

2) Improving alignment with electricity supply and demand:

Demand on the Yukon Integrated System varies significantly on both seasonal and diurnal timescales, with peaks in demand occurring in the morning and evening of cold winter days, as shown in Figure 1. For this figure, the hourly forecasted demand of the ten days with the highest forecasted peak demand, based on modelling for 2025, was averaged to demonstrate the forecasted hourly demand curve for a typical cold winter day in 2025. The figure shows that demand on the Yukon Integrated System peaks in the morning and evening, corresponding to when residential space and water heating demand is highest.[5] This is consistent with demand curves in other jurisdictions. For example, Ontario's winter time-of-use rates include on-peak periods of 7 to 11 am and 5 to 7 pm, corresponding to morning and evening winter peaks. Actual hourly demand curves vary significantly, as demonstrated in Figure 2 which shows the total Yukon Energy generation in MW for the five days with the highest peak demand in 2022. This variability in demand increases the difficulty of maintaining grid stability while efficiently using available generation assets.

Considering the hourly load forecast for 2025, the projected hourly non-industrial load will only be within 10 MW of the annual peak for just 4 hours over the year, or less than 0.05% of the year (Figure 3). Any dependable reduction of the non-industrial peak demand on those critical days, typically the coldest days of the winter, would reduce Yukon Energy's need for additional dependable generation capacity – a rapidly increasing need whose growth in recent years has been met by costly rented thermal generators.

Yukon Energy's DSM programs target the periods of peak demand throughout the winter, especially on those coldest winter days, to reliably reduce the peak demand and therefore the need for additional dependable capacity resources. Yukon Energy's DSM programs will shift demand from the periods of highest demand to periods of lower demand, flattening the hourly demand curve, reducing the overall annual peak demand and therefore Yukon Energy's need for additional dependable generation capacity while supporting alignment between the supply and demand of electricity on the Yukon Integrated System.

[5] Supporting sources: https://uknowledge.uky.edu/cgi/viewcontent.cgi?article=1074&context=peik_facpub - Space Heating: Both: https://loadshape.epri.com/enduse or https://www.eia.gov/todayinenergy/detail.php?id=42915 or https://www.jstor.org/stable/44075498

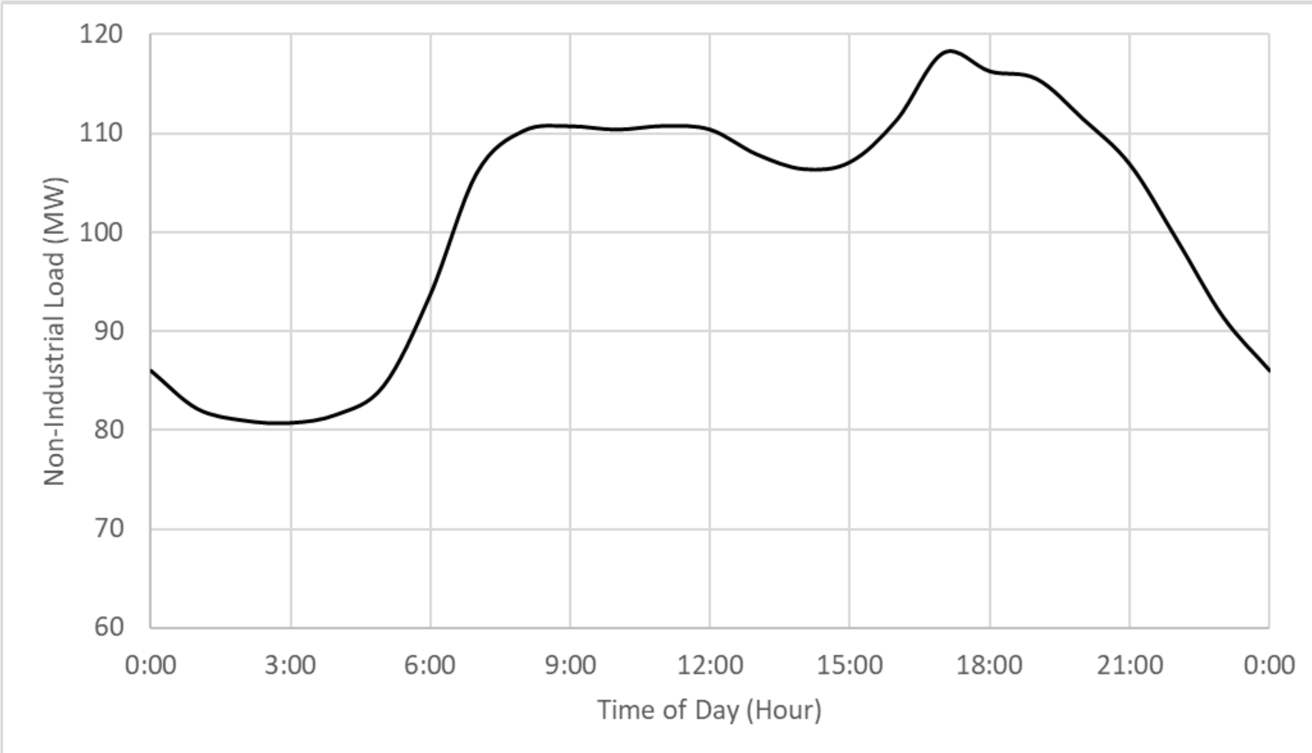

Figure 1: Typical Peak Day (2025)

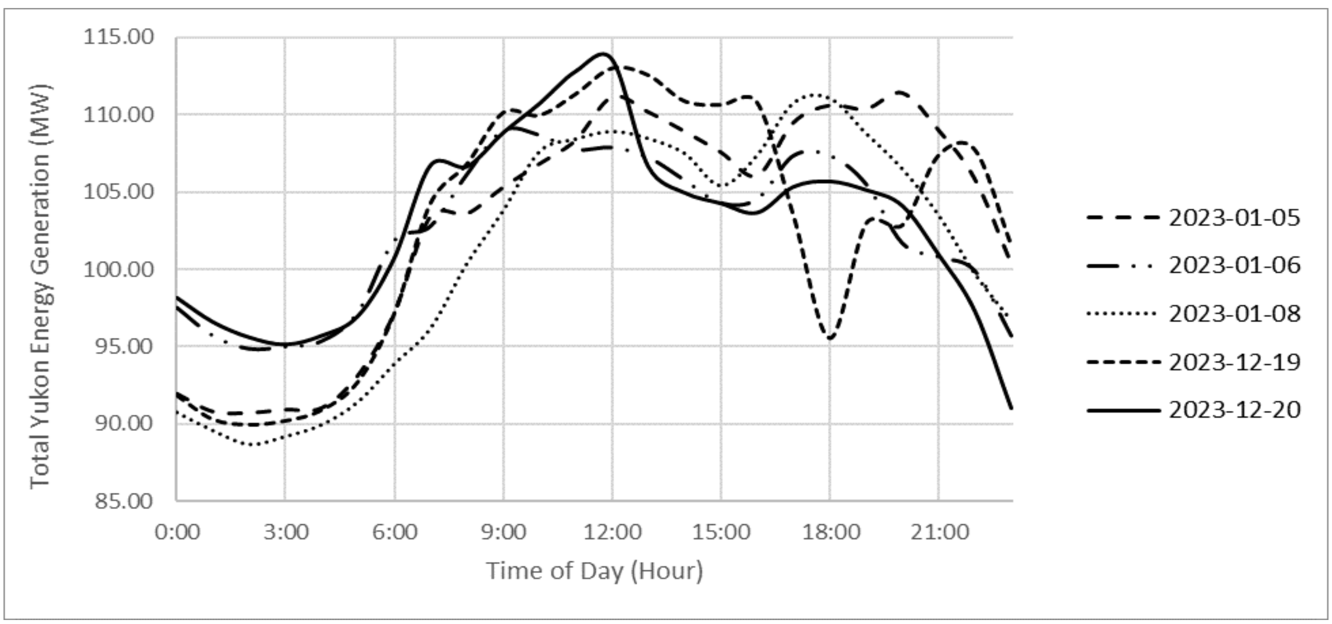

Figure 2: Top 5 Peak Days (2025)

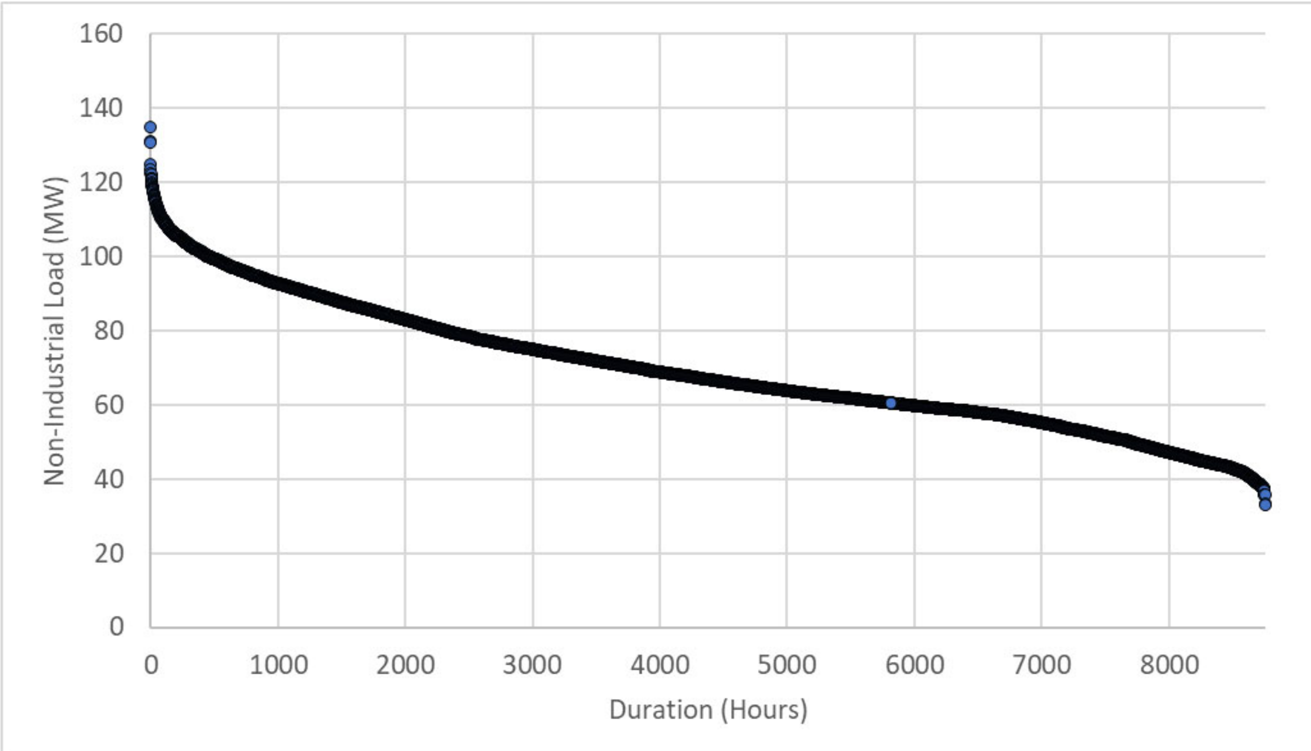

Figure 3: Non-Industrial YEC Load Duration Curve (2025)

2.2.2 OIC 2021-16 Requirement #2: Costs Must Be "Reasonably Incurred"

<u>DSM Cost-Effectiveness Tests</u>

In Appendix A of Board Order 2014-16, the YUB relied on the Rate Impact Measures test, or "RIM Test", as the primary means of assessing whether DSM program costs have been "reasonably incurred", as per requirement (2).

> Appendix A to Board Order 2014-06: "Although the Board recognizes and accepts that DSM programming will not benefit all ratepayers equally, the Board finds it undesirable that some program elements benefit some ratepayers – i.e. the participants and Utilities at the expense of others – i.e. non-participants. The Board agrees with UCG's argument that low-income customers are more likely to be excluded from participating in the DSM program due to barriers, and as a result, harmed by DSM program elements that fail the RIM Test. In the Board's view all program elements must at least be rate-neutral for all ratepayers."

The RIM Test is one of the five most common tests for evaluating the cost-effectiveness of DSM programs. All five are defined below, based on the National Standard Practice Manual (NSPM) for Benefit-

Cost Analysis of Distributed Energy Resources (National Energy Screening Project, August 2020). Table 1 summarizes the benefits and costs included in the four utility-focused tests.

- Utility Cost Test (UCT): Focuses on the perspective of the utility, including all benefits and costs that affect the operation of the utility system and the provision of electric services to customers. Includes all benefits and costs associated with a utility's revenue requirements. Identifies the impact of a DSM program on utility-system costs and average customer bills. Recommended as the foundational test for assessing DSM program cost-effectiveness.

- Total Resource Cost (TRC): Similar to the UCT, but considers the combined perspectives of the utility and participants. Some non-energy benefits and participants' contributions are included. Particularly relevant for fuel-switching and low-income programs.

- Societal Cost Test (SCT): Focuses on the perspective of society as a whole, including all relevant non-energy benefits (greenhouse gas emissions, air quality, noise, economic development, energy independence, equity, etc.). Non-energy benefits may be difficult to quantify.

- Rate Impact Measures Test (RIM): Indicates whether a DSM program will increase or decrease rates. Accounts for all utility costs incurred to implement the DSM program, including lost revenues as a cost, and all reductions in utility costs associated with the DSM program. Does not consider bill impacts or participation rates, which are critical for understanding distributional equity. See "Limitations of the RIM Test" for more details.

- Participant Cost Test (PCT): Differs from the above tests by only including costs and benefits incurred and experienced by the participant of DSM programs, not the utility. The NSPM advises against the use of the PCT for assessing the cost-effectiveness of DSM programs, instead supporting its use for evaluating the need for financial incentives to increase participation rates. As such, it has been excluded from Table 1.

Table 1: DSM Program Cost-Effectiveness Test Comparison

BENEFITS	Utility (UCT)	Total Resource Cost (TRC)	Societal (SCT)	Rate-Payer (RIM)
Avoided Fuel Costs	✓	✓	✓	✓
Avoided Capacity Costs	✓	✓	✓	✓
Non-Energy Benefits	✕	Some	✓	✕
COSTS				
Incentives	✓	✓	✓	✓
Customer Contribution	✕	✓	✓	✕
Utility Program Administration	✓	✓	✓	✓
Lost Revenues	✕	✕	✕	✓

Limitations of the RIM Test

The RIM Test was originally developed for the California Standard Practice Manual (CSPM) in 2001. The CSPM stood as the primary source of demand-side management program evaluation best practices for nearly 20 years. The NSPM for Benefit-Cost Analysis of Distributed Energy Resources was released in August 2020 and included updated guidelines DSM program cost-effectiveness. This included updated recommendations on the RIM Test's suitable uses and limitations, which encourage regulators to limit the use of the RIM Test to assessing the need for program equity considerations, such as programs tailored to low-income households. Other cost-effectiveness tests, such as the UCT and TRC, were identified as being more suitable for evaluating DSM program and portfolio cost-effectiveness. The NSPM identifies the following limitations of the RIM Test:

- Cost-effectiveness analyses should account only for future, incremental benefits and costs, as required by the *Conduct Forward-Looking, Long-term, Incremental Analyses* principle. The RIM Test accounts for sunk costs (i.e., lost revenues) and is such inappropriate to use for benefit-cost analysis.

- Cost-effectiveness analyses are intended to answer the key question of which utility DSM investments are expected to have benefits that exceed costs. Rate impact analyses are intended to answer the question of how much will utility DSM investments impact rates for one group of customers compared to another. The RIM Test attempts to answer both of these questions in a single analysis, which conflates the two questions and thus does not answer either one.

- The RIM Test does not provide useful information about what happens to rates, in terms of the magnitude of impact, as a result of DSM investments. A RIM benefit-cost ratio of less than one (1.0) indicates that rates will increase (all else being equal) but does not inform the extend of the rate impact – either in terms of the percent (or ¢/kWh) increase in rates or the percent (or dollar) increase in bills. In other words, the RIM Test results do not provide any context for regulators or stakeholders to consider the magnitude and implications of the rate impacts.

- Application of the RIM Test will not result in the lowest cost to customers. Instead, it may lead to the lowest rates (all else being equal). However, achieving the lowest rates is not the sole or primary goal of DER planning. Maintaining low utility system costs, and therefore low customer bills, may warrant priority over minimizing rates.

- Application of the RIM Test can lead to perverse outcomes. The RIM Test can lead to the rejection of significant reductions in utility system costs to avoid what may be insignificant impacts on customers' rates. For example, a DER might offer millions of dollars in net benefits under the UCT (i.e., net reductions in utility system costs) but be rejected as not cost-effective if it fails the RIM Test. It may well be that the actual rate impact would be so small as to be unnoticeable. Rejecting such large reductions in utility system costs to avoid de minimus rate impacts is not in the best interest of customers overall.

- Lastly, the RIM Test results can be misleading. For a DER investment with a RIM benefit-cost ratio of less than one (1.0), the net benefits (in terms of present value dollars) will be presented as negative benefits. A negative net benefit implies that the DER investment will increase costs. However, as described above, the costs that drive the rate impacts under the RIM Test are not new incremental costs associated with DERs. They are existing costs that are already in current electricity or gas rates. Any rate increase caused by lost revenues would be a result of recovering those existing fixed costs over fewer sales, not as a result of incurring new costs. However, utilities and others frequently present their RIM Test results as negative net benefits, implying that the DSM investment will increase costs, when in fact it may not – a RIM Test result below 1.0 only indicates participation equity and rate impact considerations should be included in the DSM initiative.

ICF DSM Cost-Effectiveness Report

ICF Canada's "Demand Side Management Design for the Yukon: Strategic Regulatory Support" report ("the ICF Report"), commissioned by Yukon Energy in 2021, expands upon the NSPM's stated limitations of the RIM Test (see Attachment 5.2A-2.1 for copy of the ICF Report):

> "At the most basic level, the RIM attempts to integrate short-term/existing impacts and long-term impacts into a single measurement that does not account for additional context. But more importantly, even when cost and benefits are accurately calculated, the RIM conflicts with basic economic theory by accounting for sunk costs in decision-making. That is, the additional "costs" associated with the lower bill revenues are not new costs resulting from the investment, they are simply existing costs that are automatically reallocated. As a result, using the RIM as a decision-making tool leads to perverse outcomes that are not in the best long-term interests of ratepayers, or society as a whole."

The ICF Report also included a thorough review of how DSM program cost-effectiveness is evaluated across North America, including specifically how various jurisdictions consider RIM Test results. The TRC test is most commonly used, with UCT typically used as a secondary test in program and portfolio evaluation. Modified TRC tests, with certain non-energy benefits included such as emissions, have become increasingly popular in recent years. The PCT is rarely used; when it is used, it is only used as a secondary test and presented as a simple payback period as an indication of potential participation rates. Use of the RIM Test is uncommon; when it is used, it is only used as a secondary test. These trends generally align with the NSPM's recommendations, particularly concerning the limited role of the RIM Test.

Yukon Energy's DSM Portfolio

Based on a report by ICF Canada entitled "Demand Side Management Program Design for YEC", commissioned by Yukon Energy in November 2021, the preliminary cost-effectiveness test results of each program in Yukon Energy's DSM Portfolio are presented in Table 2, below. Given the portfolio's focus on demand response – mitigating the utility's capacity requirements – the levelized cost of capacity (LCOC) is included, as provided in the same report.

Table 2: DSM Program Cost-Effectiveness – Preliminary Results

Phase	Program	UCT	TRC	PCT	RIM	LCOC ($/kW-year)
1	Residential Demand Response	1.9	1.3	0.6	1.9	$105
2	Dual Fuel Demand Management	1.6	1.9	1.3	1.6	$120
	Customer Product Coupons	2.5	1.6	4.8	0.5	$134
3	Demand Response EV Charging	1.7	2.8	2.7	1.7	$116
	Commercial Demand Response	1.3	1.3	1.1	1.3	$149
Overall Portfolio (2030)		1.8	1.8	1.3	1.5	$158

* Note: The "Customer Product Coupons" program was originally included in the DSM Portfolio, as recommended in the ICF report. However, this program has since been removed to avoid duplication of programs currently offered by the Yukon Government and due to equity concerns raised by the program's failure of the RIM test.

These preliminary results show Phase 1's Residential Demand Response program failing the PCT, indicating participants do not directly financially benefit from the program. Given the program's strong UCT and RIM results, the program's incentives could be increased to improve the PCT result while remaining cost-effective (UCT > 1.0) and equitable (RIM > 1.0). Additionally, strong public interest in the DSM Residential Demand Response Pilot, which offered similar benefits to participants and was ultimately oversubscribed, suggests a low PCT result may pose a low risk to program success.

All programs in the DSM Portfolio have a LCOC significantly lower than Yukon Energy's current marginal source (rental diesel, new diesel replacement)[6]. This result, together with all programs having a UCT greater than 1.0, demonstrates that all programs are cost-effective and should therefore be considered "reasonably incurred" as per OIC 2021-16. This analysis further demonstrates how Yukon Energy proposes that the UCT is used to assess the cost-effectiveness of DSM initiatives in the future.

Best Practices & Recommendations

The NSPM recommends the RIM Test only be used to identify the need for further equity concerns when developing DSM programs, rather than relying on the RIM Test to evaluate the cost-effectiveness of a DSM program – that is, whether costs were "reasonably incurred". This inclusion of equity considerations

[6] See Appendix 5.1A, section 5.1A-1 on Thermal Infrastructure (16.5 MW) which estimates LCOC of $192/ kw-yr for 5 MW diesel replacement at Faro, assuming 40 year project life and YEC WACC for new rate base of 6.018%/year per 2024 GRA (60% new debt financed at 4.23% and 40% equity financed at 8.70% per the current Application). LCOC for rental diesels (average for all units in 2024) with the same WACC and a 10 year life applicable to DSM programs is $194/ kW-yr with 3% annual inflation of rental costs and $202/kW-with 45 annual inflation of rental costs. (Section 5.1A-1 provides higher LCOC for diesel rental assuming 40 -year life compatible with the diesel replacement units project life.)

addresses the YUB's equity concerns, as expressed in Appendix A to Board Order 2014-06 (see "Limitations of the RIM Test").

The ICF report highlighted, one Canadian jurisdiction whose approach to DSM cost-effectiveness that aligns with NSPM recommendations – Nova Scotia. There, rate impacts of DSM programs are only considered internally at a high level to assist in portfolio decision making, not for evaluating whether a particular program should proceed at a regulatory level. To mitigate any impacts of rate increases on customers not participating in DSM programs, targeted programs are developed to reduce barriers to participate for low-income households and other populations considered less likely to participate in DSM programs.

The ICF Report provides the following recommendations, which align with both the NSPM recommendations and findings from the ICF Report's jurisdictional scan:

1) *Use the Utility Cost Test (UCT) as the primary decision-making factor:*

ICF suggests that the utility cost test is most reflective of the YEC's needs, as it is most suited to determine the relative value of programs in terms of alleviating the cost of delivering electricity services to Yukon. The UCT is the best indicator to compare the cost and benefit of DSM directly with supply-side costs, since the supply-side financial costs are entirely incurred by the utility. Passing the UCT demonstrates that a DSM program is a more prudent use of ratepayers' money than its corresponding traditional supply-side investment. As such, pursuing DSM programs that pass the UCT is consistent with the YUB's mandate to ensure that YEC employ ratepayers' money in the most prudent way.

The UCT may be presented as a cost-benefit ratio or as a levelized cost of energy (LCOE) or levelized cost of capacity (LCOC), which can be stacked against other supply-side resource options to make a direct comparison. LCOE and LCOC are primary factors that drive the decision of YEC on the supply-side.

Three other tests should also be computed – TRC, RIM and PCT – to provide additional information regarding who benefits and who pays, but it is the UCT that should drive decisions on which programs should be approved.

ICF notes that DSM programs for hard-to-reach customers often are more costly to deliver, however, there may be benefits to providing these customers with greater access to such programming. Such customers typically have higher non-participant rates as a group, and therefore do not have options to mitigate any DSM rate impact within their rate class. Therefore, ICF also recommends that a program which does not pass the UCT, but has other policy justifications (e.g. low-income customer support) be considered.

2) *ICF does not recommend factoring in non-energy benefits in cost-effectiveness tests:*

Non-energy benefits (or costs) are defined as the monetized value of economic, environmental or social impact of DSM, such as greenhouse gas abatement, job creation, or gain in comfort. A large number of jurisdictions do factor in non-energy benefits, but no clear rules or approaches exist regarding how to monetize them. A key drawback of factoring in non-energy benefits is the significant level of effort associated with computing tests. This is because they are resource-intensive to monetize and because they can cause intense and costly debates between stakeholders on the monetization methodology. Furthermore, non-energy benefits are factored into the modified TRC or SCT, but they are not factored into the UCT, which is the test that ICF recommends YEC use as the primary decision-making factor.

3) *ICF suggests reporting on cost-effectiveness results to the regulator at the program level:*

Program level screening will be sufficient for the regulator to determine the cost-effectiveness of DSM activities in the Yukon. ICF does suggest that individual measures are screened by YEC for cost-effectiveness for program design purposes, but not reported at the regulatory level. Regulatory scrutiny of measure or portfolio level cost-effectiveness would not add additional value and would be largely redundant alongside program level analysis. ICF also recommends that a program which does not pass the UCT but has other policy justifications (e.g. low-income support) be considered.

Implementation of these recommendations would support an accelerated implementation and expansion of Yukon Energy's DSM Portfolio, reducing the delay in achieving the 7+ MW in dependable capacity that the DSM Portfolio will provide by 2030. With these recommendations in place, Yukon Energy's DSM portfolio would be deemed "reasonably incurred" if each program's UCT result is greater than 1.0 (UCT > 1.0) and with a levelized cost of capacity less than that of the marginal source (rental diesels, new diesel replacements)[7].

[7] Ibid.

Participation Equity Considerations

Preliminary results for all cost-effectiveness tests indicate that all programs with Yukon Energy's DSM Portfolio will pass the UCT, TRC, and RIM, with LCOC values lower than the $212/kW-year benchmark. Furthermore, all programs will the exception of the Residential Demand Response Program also pass the PCT (see page 5.2-20). Nonetheless, efforts are underway to reduce barriers for sectors of the population that may otherwise be unable or less likely to participate. To date, this has included the following efforts:

1. Social Housing: YEC has engaged with the Yukon Housing Corporation (YHC), the primary provider of social housing in the Yukon, responsible for hundreds of social and government housing units across the territory. While agreement negotiations are underway, a total of 190 units across 8 multi-unit residential buildings (MURBs) have been identified as potentially suitable for electric hot water tank controllers. This additional demand-response capacity benefits YEC, while the hot water tank controllers and accompanying leak detection sensors support YHC's property management efforts. The economies of scale provided by installations in MURBs, together with the potential for YHC staff to perform the installations at no additional cost beyond the equipment costs, make this an excellent opportunity to support the inclusion of low-income households in YEC's DSM Portfolio that improves the portfolio's overall cost-effectiveness.

2. Rental Housing: YEC has developed a landlord-tenant agreement and will target participant pathways to facilitate the participation of households that are renting their home or apartment. This approach will be informed through engagement with the Yukon Residential Landlord Association and with the public, such as at the Fireweed Community Market, with the objective of lowering participation barriers for Yukoners living in rental housing.

3. First Nations Housing: YEC has engaged with multiple Yukon First Nations with the intention of developing mutually beneficial partnerships around the installation of demand-response devices in Yukon First Nations-owned housing and the participation of the households in Yukon Energy's demand-response programs. As with YEC's intentions in partnering with YHC, these partnerships, once established, will provide YEC with additional demand-response capacity, while the hot water tank controllers and accompanying leak detection sensors support each First Nation's property management efforts.

These efforts to support the equity of YEC's DSM Portfolio have come at no additional cost to YEC's DSM Portfolio and therefore have not impacted cost-effectiveness. Instead, engaging with local entities managing numerous residential units improves the cost-effectiveness of YEC's residential demand response program through economies of scale – fewer property owners to coordinate with, fewer communication hubs to purchase and install, etc. – while strengthening ties with our local partners.

Conclusions

Concerning whether costs for Yukon Energy's current and planned DSM programs are reasonably incurred, and the evaluation of cost-effectiveness of utility-run DSM programs moving forward, the above business case assessment has demonstrated the following key points:

- All of Yukon Energy's current and planned DSM programs meet both the RIM and UCT cost-effectiveness tests, with additional steps taken to support program equity.
- Equity-based considerations previously identified by the YUB, including participation barriers that low-income households may otherwise face, are being actively addressed in a manner that does not negatively impact program cost-effectiveness.
- The UCT Test is the most suitable cost-effectiveness test for utility-led DSM initiatives in the Yukon, evaluated at the program level for regulatory approval, presented as a cost-benefit ratio and/or levelized cost of capacity,
- The RIM Test is only suitable for identifying the need for participation equity considerations; a RIM Test result below 1.0 indicates a need to prioritize participation equity but does not indicate a particular program should not proceed.

2.2.3 OIC 2021-16 Requirement #3: Not be in duplication of DSM programs participated in or provided by another Yukon public utility or the Yukon Government.

Attachment 5.2A-2.2, entitled "Yukon DSM Program Comparison", provides a comprehensive comparison of DSM- and related programs offered by various territorial government departments, crown corporations, and utilities. From this comparison, it is clear that there is no duplication of DSM programs between Yukon Energy's DSM programs and DSM programs participated in or provided by another Yukon public utility or the Yukon Government. Furthermore, all included entities are in regular communication to support each other's energy- and climate-related initiatives while ensuring no DSM program duplication occurs, such as through the Advisory Group on Energy Demand and Supply (AGEDS) and the DSM Working Group. Two key comparisons are highlighted below:

1) Smart Thermostats & Hot Water Heater Controllers

Yukon Energy's upcoming residential demand response program, following a "Direct Install" program model, will provide smart thermostats and hot water tank controllers to participants, purchased and installed at Yukon Energy's costs in return for the homeowner's participation in Yukon Energy's demand response events for a predetermined period of time. With this model, the purchase and installation of the device(s) is considered an upfront capital incentive, with no on-going incentive offered.

Yukon Energy is considering transitioning to a "Bring Your Own Device" program model in Fall 2024, wherein eligible Yukoners connected to the Yukon Integrated System with compatible devices could enroll in Yukon Energy's demand-response programs and receive an on-going incentive, such as a credit on their utility bill annually. With this model, an on-going inventive is offered in lieu of an upfront capital incentive.

Yukon Energy has been in coordination with the Yukon Government's Energy Branch in anticipation of such a transition, including exploring the possibility of the Energy Branch expanding their Good Energy program to include rebates smart thermostats and hot water tank controllers. To prevent program duplication, any such rebates (considered a form of upfront capital incentive) would only be offered once registration for Yukon Energy's "Direct Install" program closes. The Energy Branch would not offer any on-going incentives for these devices, instead directing rebate applicants to Yukon Energy's DSM programs.

With this coordinated approach, Yukon Energy and the Yukon Government's Energy Branch are supporting each other's objectives centered around providing Yukoners with a clean, reliable, and affordable power grid while reducing the Yukon's annual greenhouse gas emissions and avoiding DSM program duplication.

2) Yukon Energy & ATCO Electric Yukon

As most electric utility customers in the Yukon purchase power from ATCO Electric Yukon ("ATCO"), most participants in Yukon Energy's DSM programs will also be ATCO customers. Yukon Energy and ATCO have been in regular communication to support program implementation and mitigate any impact on ATCO's customers from Yukon Energy's DSM programs. Furthermore, Yukon Energy has expressed an openness to sharing recommendations and lessons learned from its DSM programs should ATCO pursue any DSM initiatives in communities not served by the Yukon Integrated System, while avoiding program duplication.

2.3 Business Case Conclusion

The above business case assessment has demonstrated that Yukon Energy's current and planned DSM programs as described that affect rate base costs in 2023 and 2024 meet all three requirements stipulated by OIC 2021-16:

1) Meet the definition of "demand-side management program": Yukon Energy's DSM programs will reliably reduce the peak demand on the Yukon Integrated System, reducing the need for additional dependable generation capacity by improving alignment between electricity supply and demand.

2) Costs must be "reasonably incurred": All DSM programs that will be planned and implemented by Yukon Energy pass both the Ratepayers Impact Measures (RIM) test and Utility Cost Test (UCT), with additional cost-effective measures to address previously expressed program equity concerns regarding low-income households.

3) Not be in duplication of DSM programs participated in or provided by another Yukon public utility or the Yukon Government: A thorough comparison of DSM and related programs by a variety of territorial government departments, crown corporations, and utilities. As demonstrated by this comparison, there is no duplication of DSM programs between Yukon Energy's DSM programs and DSM programs participated in or provided by another Yukon public utility or the Yukon Government.

Based on the above assessment, Yukon Energy's actual and forecast costs incurred in the planning and execution of the described Yukon Energy's DSM programs are prudent, reasonable and eligible to be recovered through rates.

SECTION 5.2A-3: SOUTHERN LAKES ENHANCED STORAGE PROJECT (RATE BASE ADDITION OF $8.784 MILLION IN 2023)

The Southern Lakes Enhanced Storage Project (SLESP), also previously known as Marsh Lake Storage, was created as a means of enhancing winter energy at the Whitehorse Rapids generating station to displace higher cost thermal generation that would otherwise be required. As reported in the 2012/13, 2017/18 and 2021 GRA's, 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 in the fall 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.

In November 2022, the Carcross/Tagish First Nation (CTFN) notified YEC that it would not support completion of the SLESP. As a result, YEC concluded that the project would no longer offers a net economic benefit to ratepayers as there is no reasonable probability that the project will proceed. As directed by the Board in Order 2013-01 (para 337 of Appendix A), YEC was therefore required to cease work on the SLESP project. Based on YEC's decision not to proceed further with the project, feasibility study costs to date of approximately $8.784 million will be amortized over 10 years, starting in 2023.

Information on the justification for pursuing SLESP and related project costs is provided below, organized by each earlier GRA review period.

Project Review in 2012/13 GRA

Yukon Energy's 2012/13 GRA application noted that the Marsh Lake Fall/Winter Storage Project (then estimated at about 1.6 MW; 7.7 GW.h/year) was reviewed as part of the 2006 20-Year Resource Plan[8]. In its report and recommendations to the Minister of Justice regarding the 2006 20-Year Resource Plan, the YUB noted that, "[it] sees some viability to this project in terms of either displacing diesel generation or delaying future capacity additions" and recommended the project be retained in the Resource Plan but

[8] As scoped during the 2006 Resource Plan, the project involved seeking changes to the Whitehorse Rapids water licence to allow Yukon Energy to reduce the amount of water it releases from Marsh Lake in non-flood years from August 15 to the end of September, to allow that water to be used instead during the peak winter generation period (during flood years, no change would be made during August and September, until after flood levels subside). In all cases, the water levels would remain within the lake level limits currently experienced (i.e., the peak controlled level would be below the natural high water levels experienced in the lake). No new physical works were expected to be required.

removed as a near-term project (i.e., at that time "near-term" referred to commitments by 2009 to meet loads out to 2012)[9].

The 2012/13 GRA reviewed changes to the project since 2006, and identified the SLESP (then referred to as Marsh Lake Storage) as a relatively small project, with earliest in-service assumed in 2014 (first full year 2015). YEC expected that a YESAB project proposal could be filed in early 2013 (with a Designated Office level review). Once the Designated Office review was completed and decision documents issued a Yukon Water Board application would be filed to amend the current water licence. It was expected that these review processes could be completed before the end of 2013 or early in 2014. Mitigation work would be undertaken in the summer of 2014, enabling the earliest in-service date in the fall of 2014.

The 2012/13 GRA estimated a project capital cost (2010$) of $10.5 million. Mitigation design (shoreline erosion and surface water) was 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 over a 65-year life, focused in winter months at the current Whitehorse plant. Full Utilization LCOE (2010$) was estimated at 8.5 cents per kW.h (i.e., well below the approximate 29 cents per kWh cost then provided for diesel fuel displaced), assuming a capital cost (2010$) of $10.5 million, and annual operating cost (2010$) of $8/MW.h. Southern Lakes 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, 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.

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

[9] "Near-term" requirements in the 2006 Resource Plan were defined as "Yukon Energy generation and transmission commitments required before 2009 for major investments with anticipated costs of $3 million or more. Given the time needed for possible construction, the assessment examines possible in-service needs to meet loads out to 2012".

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 Appendix A to 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 directed, however, that YEC was to cease work on the project if and when YEC concluded that there is no net economic benefit of the project to ratepayers.

Project Review in 2017/18 GRA

The project (which by the 2017/18 GRA was called SLESP) was not able to proceed as planned in the 2012/13 GRA due to a need for further studies and engagement activities.

Work completed between the 2012/13 GRA and the 2017/18 GRA included technical studies and assessments, engagement and consultation with various stakeholders, and extensive meetings with property owners that would 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.

YEC stated in the 2017/18 GRA proceeding that the next major milestone was obtaining First Nations support for the project in order to progress to the YESAB assessment stage. Without such support YEC stated that the project would be cancelled as there would be no reasonable possibility of successful implementation and any further costs would have no economic benefit to ratepayers. It was expected that a decision to proceed to the YESAB assessment phase would be made at a Stagegate 3 project review. Once this milestone was achieved, all project authorizations would be formally sought following the conclusion of a project assessment pursuant to the *Yukon Environmental and Socio-economic Assessment Act* and the subsequent issuance of Decision Documents from the assessment Decision Bodies.

YEC indicated in the 2012/13 GRA proceeding that it had spent almost $6.8 million to date and was forecasting an additional $8,577,830, for a total cost of $15.377 million, almost 50% higher than the 2012/13 GRA forecast, with $7.950 million forecast for effects assessment; $0.300 million forecast for YESAA assessment and permitting; and $7.127 million forecast for mitigation implementation.[10] YEC

[10] Response to 2017/18 GRA IR YUB-YEC-1-84.

noted that the level of effort and time required for stakeholder engagement as part of the planning process had not been anticipated, accounting for over $1 million of added costs; approximately $2 million of added effects assessment costs related to added baseline studies and engineering; and added forecast implementation/ mitigation costs of approximately $1.9 million reflected increased predictions of the extent of sensitive shorelines that would need protection as well as the extent of required engineering concepts and inflation over the 8-year planning period.[11]

During the GRA oral hearing in late June 2018, YEC submitted that CTFN is a decision body in the YESAB process, and that YEC had received conditional support from the CTFN to proceed to YESAB but that any benefits agreement has not been completed, and that YEC also needs to bring the project back to its board to reassess public, First Nation and government support for the project.[12]

In Appendix A to Order 2018-10, the Board stated concern with the amount of time and expenditures to date with little apparent progress, and reminded YEC that if it chooses to keep developing the project that it will have the onus to demonstrate the prudence of all expenditures related to the project.

Project Review after 2017/18 GRA

Yukon Energy completed an additional round of engagement in 2019 to confirm the level of support for the project. This included engagement with local residents in the Southern Lakes area, and Yukoners generally; as well as a further round of First Nations engagement to confirm the position of the affected First Nations (Carcross/Tagish First Nation, Kwanlin Dün First Nation and Ta’an Kwäch’än Council).

The costs forecast in the 2021 Application assumed that the project continued, with spending in WIP increasing from $7.319 million at the end of 2018 to $9.379 million by the end of 2021. Potential in service for the Project was 2023.

In Q2 2020 the YEC Board approved a budget of $1,314,000 to advance the SLESP to stagegate 3, namely the submission of a YESAB project proposal. As part of the approval of stagegate 1 activities on the WRGS Relicensing project, the Board also approved a resolution on December 8, 2021 that YEC work with Yukon government and the impacted First Nations to “pursue the inclusion of the Southern Lakes Enhanced Storage license amendments in the assessment for the relicensing”.

At the October 31, 2022 meeting of the WRGS Relicensing Senior Officials Group (SOG), the group reviewed the project scope for the relicensing of the WRGS, including potential enhanced storage

[11] Ibid., Table 1 and text.
[12] Appendix A, Board Order 2018-10, para 503.

elements (key elements of the SLESP). YEC had made previous commitments to the project partners that project changes would not be included without the support of the project partners. At the SOG meeting, representatives from the CTFN formally stated that they do not support changes to the full or low supply limits and requested that these elements be removed from the scope of the relicensing application. As a follow-up to the SOG meeting, CTFN issued a formal letter on November 6, 2022 stating their lack of support for the enhanced top and bottom storage elements (i.e., the SLESP project requirements) of the proposed WRGS Relicensing scope.

YEC has considered the implications of not receiving support from CTFN for completion of the SLESP and concluded that it has explored all options to complete the project, without success. Consequently, YEC 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 YEC, as directed by the Board in Order 2013-01, has therefore ceased work on the project.

Costs to be Amortized over 10 Years

Based on YEC's decision not to proceed further with the SLESP project, feasibility study costs to date of approximately $8.784 million will be amortized over 10 years, starting in 2023. The table below shows costs incurred by cost element and time period, including costs accounted for by YEC's internal interest cost (AFUDC, or allowance for funds used during construction) applicable to all WIP costs.

Costs ($000's)	Inception to 2013	2014-2018	2019-2021	2022	Total	AFUDC % of Total
Third-party engineering	111	14	8	3	135	25.0%
Environmental assessment	3,974	1,973	400	131	6,478	22.1%
Project management	417	53	30	10	510	26.8%
Public consultation	125	148	320	14	607	13.5%
YEC costs	302	202	35	11	550	21.9%
Stagegate 3	-	-	388	116	504	3.2%
Total	4,928	2,391	1,181	284	8,784	20.7%
AFUDC included in Total	383	749	508	180	1,820	
AFUDC as % of Total	7.8%	31.3%	43.0%	63.4%	20.7%	

Note: "AFUDC"(Allowance for Funds Used During Construction) is YEC's internal interest cost.

Approximately $7.3 million, representing 83% of total project costs, were incurred between inception and the end of 2018, and related mostly (87%) to environmental assessment studies, engineering, and public consultation activities plus related AFUDC interest costs. These costs were reviewed at a high level in the 2012/13 and 2017/18 GRAs.

The 2019-2021 costs were not reviewed in the 2021 GRA decision. Appendix A to Board Order 2022-03 concluded that given that the costs for the projects in WIP do not affect the test year rate base or revenue requirement, the Board made no findings regarding these projects at that time.

The 2019-2021 costs of $1.181 million consisted primarily of AFUDC interest costs on earlier environmental assessment and other costs plus some additional public consultation and the commencement of stagegate 3. Excluding related AFUDC costs, new expenditures focused on efforts to advance filing of a YESAB submission and consisted primarily of stagegate 3 costs of $0.384 million and public consultation costs of $0.286 million. YEC's internal AFUDC interest cost of $0.508 million accounted for 99% of the remaining $0.511 million costs.

The 2022 costs of $0.284 million consisted of AFUDC costs of $0.180 million and stagegate 3 costs (excluding related AFUDC) of $0.104 million incurred prior to receipt of the CTFN November letter.

ATTACHMENT 5.2A-2.1
DEMAND SIDE MANAGEMENT PROGRAM DESIGN FOR YEC

Demand Side Management Program Design for YEC

November 12, 2021

Submitted to:

Yukon Energy Corporation

Table of Contents

Table of Acronyms

DR	Demand response
DRMS	Demand response management system
DSM	Demand side management
EB	The Energy Branch
EM&V	Evaluation, measurement & verification
EV	Electric vehicle
HVAC	Heating, ventilation & air conditioning
LED	Light-emitting diode
LVCT	Line voltage communicating thermostat
QA/QC	Quality assurance & quality control
YEC	Yukon Energy Corporation
YUB	Yukon Utilities Board

Table of Exhibits

1 Introduction

Electricity demand in Yukon's islanded grid is increasing, and the Yukon Government has directed Yukon Energy to pursue energy-efficient practices and reduce demand at peak times, provided that there is consideration of any duplication between YEC offerings and offerings associated with the Government of Yukon.

In September 2020 the Yukon Government released their strategy for climate change, energy, and a green economy, entitled "Our Clean Future". In it, they identify the following actions as the Government of Yukon's top priorities to use energy more efficiently and better align energy supply and demand:[1]

1. Provide direction to the Yukon Utilities Board in 2020 to allow Yukon's public utilities to partner with the Government of Yukon to pursue cost-effective demand-side management measures. (YDC)
2. Establish a partnership between the Government of Yukon, Yukon Energy Corporation and ATCO Electric Yukon by 2021 that will collaborate on the delivery of energy and capacity demand-side management programs. (EMR & YEC)
3. Complete the Peak Smart pilot project by 2022 to evaluate the use of smart devices to shift energy demand to off-peak hours. (YEC)
4. Implement an education campaign for Government of Yukon building occupants and visitors by 2026 to encourage more energy efficient behaviours. (HPW)

Furthermore, on February 11, 2021, the Government of Yukon issued an Order in Council, which:

- Requested the YUB to authorize YEC to recover reasonably incurred DSM program cost from rates.
- Requested the YUB to "consider the extent of any duplication between the program for which costs are incurred and a demand-side management program provided by the Government of Yukon or in which the Government of Yukon is a participant".[2]

1.1 Goal of this Report

YEC has engaged ICF for program design of their next round of DSM programs. In response to the Order in Council, ICF has provided a careful examination of any potential duplication between these proposed programs and DSM programs provided by the Government of Yukon in which the Government of Yukon is a participant, and we have provided specific recommendations for how to address any potential interpretations of "duplication".

This document provides an overview of each proposed program including general program descriptions, target market, implementation approach, eligible technologies and measures, impacts and cost-effectiveness, evaluation methods. Discussion of detailed analysis and measure level assumptions is provided in the attached appendices and additional documentation (draft TRM & Cost-Effectiveness Model).

[1] Government of Yukon, *Our Clean Future*, 2020 < https://yukon.ca/sites/yukon.ca/files/env/env-our-clean-future.pdf>

[2] Government of Yukon, *Order in Council 2021/16 Public Utilities Act* (Whitehorse, Yukon, Canada, 2021).

1.2 Cost Effectiveness Testing

Cost-effectiveness analysis is used by DSM program administrators to assess the relative value of their programs from various perspectives. Established in the 1980s, the California Standard Practice Manual[3] outlines five standard tests and associated perspectives:

- the economy through total energy resources (TRC),
- the utility/program administrator through the utility cost test (UCT) also known as the program administrator cost test (PAC),
- the DSM program participants through the participant cost test (PCT),
- the ratepayers through the rate impact measure test (RIM), and
- society through either a modified version of the TRC, or through a test known as societal cost test (SCT),

The National Standard Practice Manual[4] largely adopted the same tests with relatively minor changes, but none that have material changes over the results of the test in Yukon.

As part of the rate filing related to the five-year DSM Plan, four out of the five standard cost- effectiveness tests were computed: TRC, the UCT/PAC, PCT, and the RIM. All test results were presented in terms of benefit/cost ratios. The last of the five standard tests, the SCT, was not computed because if the program met the TRC, it was expected to also meet the SCT, since the SCT added non-energy benefits to the TRC calculation. As well, it is resource-intensive to calculate non-energy benefits, and the assumptions involved are controversial, and a result, the SCT was not considered a viable test in Yukon mostly for practical reasons.

Given Yukon's circumstances - capacity-constrained, focus on the lowest-cost resource option, and historical precedence when selecting supply-side resource - the UCT is to be used as the primary test for decisions regarding DSM. All three other tests are secondary tests to be looked at, but that should not drive decisions.

1.3 Approach to Avoided Cost Modeling

For DSM to be considered as a cheaper alternative to supply-side options, the selection of avoided cost assumptions must be reflective of existing frameworks. For more information, please see the accompanying regulatory support document entitled Demand Side Management Design for the Yukon: Strategic Regulatory Support.

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[3] **CPUC. (2001). *California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects. California Public Utilities Commission.* California, United States of America. https://doi.org/10.1016/B978-1-85617-804-4.00018-5**

[4] **Woolf, T., Neme, C., Kushler, M., Schiller, S. R., Eckman, T., & Michals, J. (2017). National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources -- Edition 1 Spring 2017. Retrieved from https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf**

Due to a more recent pressing need for the Yukon Territory to meet N-1 reliability criteria, the focus of DSM has shifted from a low-cost source of energy supply in 2014 to include capacity procurement. YEC seeks capacity from DSM; both from traditional DSM programming, demand response types of programs, or both, particularly during the peak and mid-peak demand periods. To account for this change, the approach to modeling avoided cost has been upgraded to differentiate between the avoided cost of capacity (diesel emergency reserve, in $/kW-yr) and the avoided cost of energy.

Furthermore, under YEC's current supply and demand forecast, the supply in energy is expected be a mix of LNG, diesel and hydro power. During some portion of the year, now and in the foreseeable future, YEC will have to spill water from its reservoirs, which means that electricity use during periods when they would result in additional water spill is worthless. To account for this change, the structure of the DSM cost effectiveness model has been modified to accommodate time varying avoided energy costs as part of the cost-effectiveness analysis.

1.4 Structure of this Report

This report is structured in two major sections, starting with Section 2 on the proposed portfolio of programs, followed by a breakdown of each of the programs (Section 3).

Each of these programs contains a detailed discussion on program description, target market, approach to implementation, eligible technologies and measures, impact, budget and cost effectiveness, tracking, QA/QC, and EM&V, and where applicable the recommended approach to avoid EB/YEC duplication of program offerings.

Appendix A outlines the steps for the approach and analysis of the DSM programs and capacity DSM programs.

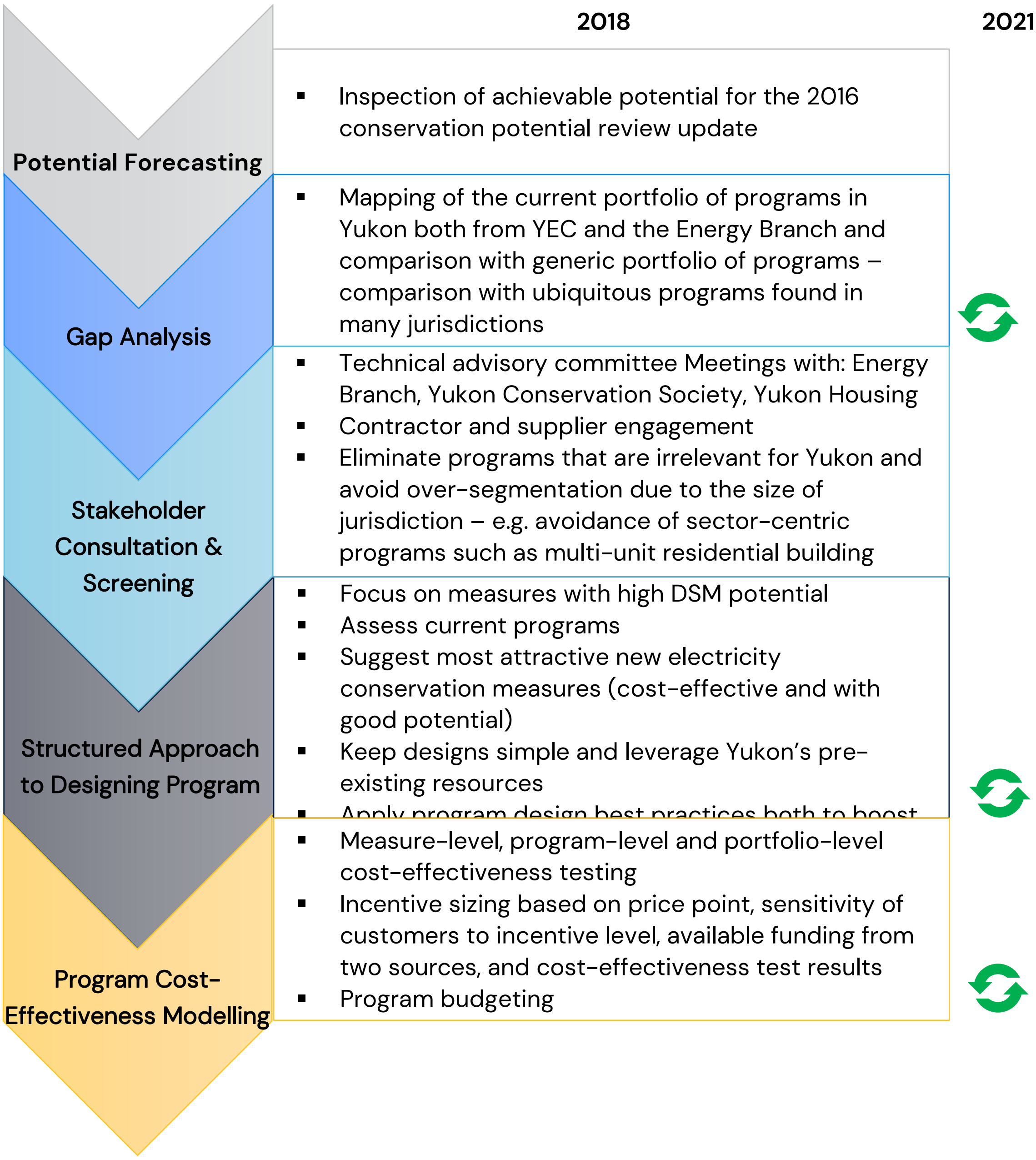
Programs that were previously considered, but were removed from the design due to their poor cost-effectiveness test result and/or due to duplication concerns with Energy Branch offerings are described in Appendix B.

2 Proposed Portfolio of Programs

2.1 Structured Approach to Program Design

Exhibit 1 provides an overview of the structured approach to program design that was utilized. The 5 steps included in the exhibit were carried out in 2018, and then in 2021 the gap analysis, structured approach to designing and the program cost-effectiveness testing was updated based with the goal of avoiding duplication between the proposed YEC offerings and the Government of Yukon DSM programs currently in market.

Exhibit 1: Structured Approach to Program Design

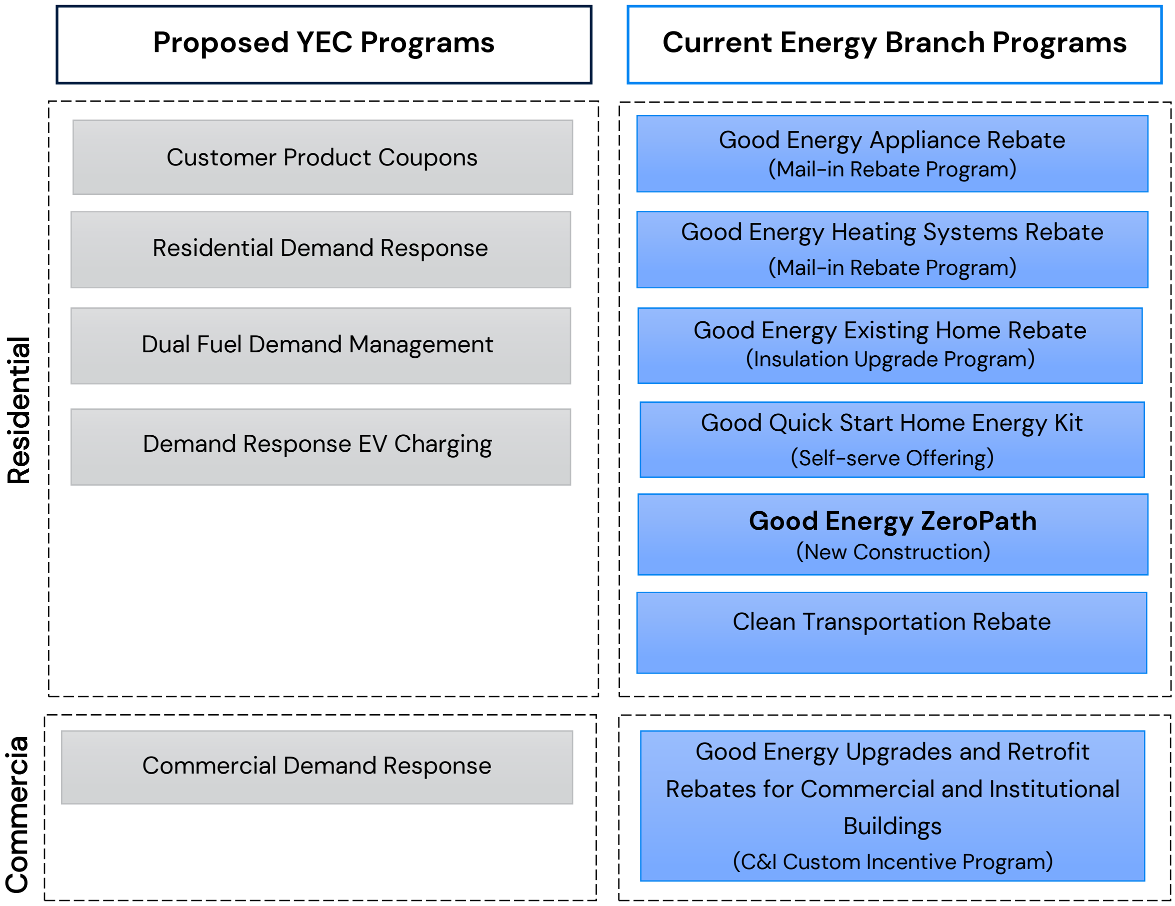


2.2 DSM Portfolio Overview & Economics

Exhibit 2 provides an overview of the YEC residential and commercial DSM and DR programs being proposed, and how they relate to programs currently being offered by the Energy Branch. The proposed YEC programs were selected from a broader list of previously considered programs. ICF and YEC selected these offerings due to their contribution towards peak reduction targets, their UCT score, and their avoidance of duplication with Energy Branch offerings. Programs that were removed from consideration are provided in Appendix B.

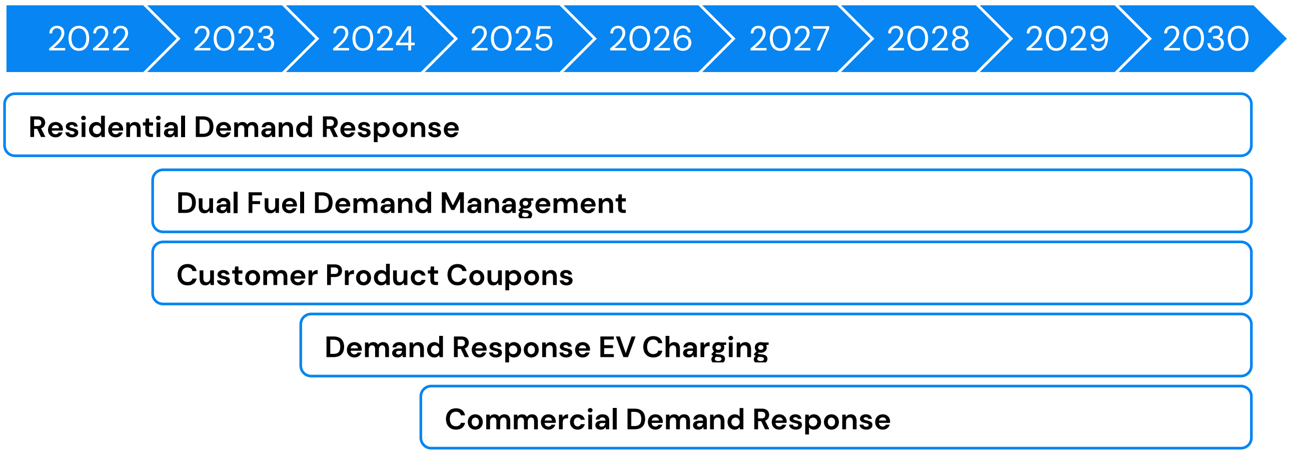
The YEC Program names listed below and throughout this document are preliminary suggestions from ICF and are subject to change.

Exhibit 2: DSM Overview



The proposed YEC programs will be rolled out over the next few years, starting in 2022. The proposed program delivery periods are illustrated in the following exhibit. The program designs and approval process will be for 3 years of programming but will be submitted and reviewed with each General Rate Application (2 year cycle).

Exhibit 3: Proposed Program Staggering



An overview of the economics of all the DSM and capacity DSM programs can be found in the exhibit below. This includes the impact, budget, and cost-effectiveness test results at a portfolio level and by program. Exhibit 4 compares the forecasted demand savings compared against the savings target for each year. Based on these estimates, there will be a need for diesel generator rental to cover the capacity difference in the first 3 years (2022-2024).

Exhibit 4: Net Savings, all Programs

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Total
Lifetime MWh:	0	2,275	3,610	4,265	4,270	4,276	1,497	1,497	855	22,683
Annual MWh:	0	290	400	432	432	432	214	214	214	N/A
Net kW Savings – Generator Level:	868	2,104	4,202	7,756	11,357	15,158	18,165	21,522	24,398	N/A
Net kW Goal:	2,300	4,600	7,000	7,000	7,000	7,000	7,000	7,000	7,000	N/A
Difference:	-1,432	-2,496	-2,798	756	4,357	8,158	11,165	14,522	17,398	N/A

The following exhibit provides the estimated incentive and non-incentive budgets for each year. It is assumed that the implementer will carry out the design and delivery of the portfolio of programs, and a half full-time-equivalent staff will be required from YEC to assist in managing the portfolio.

Exhibit 5: Utility Expenditure (in $1,000)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Total
Incentive:	$472	$809	$1,360	$2,059	$2,085	$2,142	$1,580	$1,716	$1,028	$13,251
Non-Incen:	$457	$612	$692	$790	$701	$666	$410	$438	$407	$5,173
YEC:	$100	$100	$100	$100	$100	$100	$100	$100	$100	$900
Total:	$1,029	$1,521	$2,152	$2,949	$2,886	$2,908	$2,090	$2,254	$1,535	$19,324

Exhibit 6 summarizes the cost-effectiveness test results of the portfolio at each 3 year milestone. The UCT result is approximately 1.8-1.9 in each case.

Exhibit 6: Cost-effectiveness

	TRC	UCT	PC	RIM	Levelized Cost ($/kWh) – Meter Level	Levelized Cost ($/kW-year) – Meter Level
Year 3	1.5	1.8	1.0	1.5	$0.69	$145
Year 6	1.5	1.9	1.2	1.5	$0.80	$100
Year 9	1.8	1.8	1.3	1.5	$1.94	$158

2.3 Demand Response Management System

The proposed suite of programs are predominantly demand response offerings, and therefore YEC would benefit from securing a Demand Response Management System (DRMS) platform that is compatible with a variety of devices. This would allow YEC to add a variety of devices to their system as they expand their program offerings to include electric vehicle charging demand response, and commercial demand response. It also lowers the risk of relying individual control equipment providers' DRMS platforms that YEC may lose access to if there are disruptions in the market, as YEC found with the Peak Smart pilot.

DRMS systems often charge an annual fee plus a per-device annual fee. The annual DRMS platform fee is included in the non-incentive budget estimates starting in Year 1, and are shared across each program in a given year. The per-device fees are included in the measure costs/incentives for each program.

ICF has investigated a number of DRMS platforms, and it is challenging to identify a provider that has experience with line-voltage communicating thermostats (LVCT). DRMS platforms providers predominantly work with summer-peaking utilities with AMI data. However, DRMS providers should see the value in building LVCT compatibility given the focus on electrifying heating systems to reach decarbonization targets across North America.

The DRMS platform's compatibility with the Level 2 chargers being promoted through the Energy Branch's Clean Transportation Rebate for managed charging should also be considered.

2.4 Low Income Customers

ICF designed a 'whole home' program for low income residents, but it was removed from the portfolio as it did not pass the cost effectiveness test (see Appendix B). Instead of designing a specific program offering for these customers, ICF recommends that YEC designate a portion of their participation target and recruitment of their residential programs to low income customers. For example, YEC could collaborate with the Yukon Housing Corporation to ensure that all of their eligible homes receive smart thermostats or LVCTs, and hot water tank controllers. Further study will be required to determine the appropriateness of the direct load control measures for these customers.

3 Program Descriptions

This section provides detailed descriptions of each program in the proposed order of delivery (as per Exhibit 3).

3.1 Residential Demand Response

Dispatchable Capacity

3.1.1 Program Description

YEC launched a pilot demand management program called Peak Smart in 2019, which offered free peak-shifting thermostats for baseboard heaters and electric hot water tank controllers. The pilot was suspended in July 2021 when the supplier unexpectedly stopped support for the devices. ICF suggests a continuation of Peak Smart with a different supplier, given the value of managing customer heating demands during the winter peak periods.

There is no duplication between the proposed Residential Demand Response program and the Energy Branch's Good Energy Program. The Energy Branch does not offer any demand management programs.

Residential Demand Response program is predominantly a 'direct load control' (DLC) program that allows the YEC to start and stop curtailment events, using broadband internet and a number of home area network or cellular network solutions to send control signals and acquire data from the utility operation room to participants' home "directly" and remotely. The program is built to test the reliability and duration of the curtailment that can be achieved. It is an opt-in program; only electricity customers that are willing to have their equipment controlled by the utility during peak periods enroll. The participants do not pay for the controlled devices. The Peak Smart pilot learnings will be reviewed and integrated into the design and implementation of the Residential Demand Response program.

The penetration of electric baseboard is growing in residential dwellings in the Yukon. A 2011 Conservation Potential study conducted for the Yukon indicated that electricity is a primary source of heating for approximately 6.3% of homes. However, since then new residential developments have commonly adopted electric heating as a primary heat source due to the large percentage homes that have been built with a "super insulated" building envelope, in compliance per the bylaw of City of Whitehorse. For these types of homes, electric baseboard heating has become the standard practice of the construction industry because builders have been offsetting the high cost of the superior insulation level by not installing the duct system associated with central air. As such, a large percentage of homes developed in recent years in Whitehorse (to be confirmed in future residential end-use surveys) use electric heating, and in particular electric baseboards and floor heating. In addition, the adoption of heat pumps is being promoted by the Energy Branch, providing further need for direct load control given that heat pumps often rely on electric resistance back up heating systems on most winter days.

We propose a program that would test a few residential heating and DHW curtailment or load shifting methods, to find which ones or which combination is most suitable to Yukon customers, and Yukon Energy. Exhibit 7 provides an overview of the program measures and a brief description of the strategies employed to curtail demand. ICF has excluded electric thermal storage (ETS) measures from this program design, as there are few inherent benefits for participants and the units are large and bulky which causes some resistance to adoption. However, YEC will collaborate with the learnings from the ETS pilot being conducted by the Yukon Conservation Society and will revisit including an ETS program offering based on their findings.

Exhibit 7. Proposed Measures

Measure	DR Strategy	Description	HAN* Comms. Protocol	DLC Comms. Protocol
Line voltage connected thermostats (included in the Peak Smart Pilot)	Curtailment (with pre-heating and snapback)	Change in temperature setpoint or 'On'/'Off' control, referred to as cycling	Wi-fi, Z-Wave, Zigbee, Thread, WeMo	
Web-enabled programmable thermostats				
Domestic hot water control (included in the Peak Smart Pilot)	Curtailment	Change in temperature setpoint or 'On'/'Off' control, referred to as cycling	Wi-fi	TCP/UDP (Internet)

*HAN – Home Area Network

The program costs and demand curtailment estimated in this report have been informed based on discussions with service providers, research on similar programs, discussions with utilities delivering DLC programs. The LVCT demand curtailment estimates are based on findings from Hydro Quebec's LVCT pilot in 2017.[5] Hydro Quebec has since expanded to a full-scale program and subsidiary, called Hilo. Hilo offers three different bundles of connected devices (small home, medium home, and large home), consisting of smart thermostats, and a variety of smart plugs and dimmers.[6] Hilo also has a behavioural element, where participants opt-in to receive up to 30 automatic prompts and receive a cash reward for each kWh saved.

3.1.2 Target Market

The target market for the Residential DR program includes the YEC's residential customers that use electricity as a primary source of heating. The same participants all use electricity to heat domestic hot water. All participants must be customers located on the Yukon Integrated System with an active electricity account and agree to participate in curtailment events. Participants may be offered to "override" specific events from time to time, so long as the override is not systematic. Empirical evidence have shown that the ability to override improve greatly how palatable the programs are to customers, yet participants override events relatively rarely.

Thermostats can be installed for people who own central electric furnaces (advanced low-voltage thermostat) or baseboard heating (line-voltage connected thermostat).

The recruitment efforts in Year 1 should focus on the approximately 400 participants from the Peak Smart pilot. These participants will need new devices, as their Casa devices are no longer supported.

ICF recommends that YEC collaborate with the Yukon Housing Corporation to deliver the program to eligible government housing and low income residents.

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[5] Institut de Recherche d'Hydro Quebec. *Demand Side Management with Line Voltage Communicating Thermostats: A Real Life Experiment*, November 15, 2017. <https://www.peakload.org/assets/36thConf/B2.MFournier_PLMA_final.pdf>

[6] Hilo, *An Affordable Smart Home that Rewards You*. < https://www.hiloenergie.com/en-ca/>

3.1.3 Approach to Implementation

The recommended approach for the Residential DR Program is a 'direct install' program. Under this program model, incentives are provided to cover a substantial portion of the capital cost of measures, often entirely. 'Turn-key' installation of the measures is performed by sub-contractors working on behalf of the utility or through a utility-approved contractor network. This program design has not included a performance incentive for ongoing participation, as a free connected thermostat is an attractive offer that has enticed many participants in programs across the country. Nevertheless, even for thermostats ongoing annual incentives are recommended to boost persistence of participation in the program. Ideally the annual incentive would be provided to participants in the form of an on-bill credit so that they easily associate the bill savings to the program and their energy costs.

The proposed DLC program would have high up-front costs since a DRMS is required to trigger curtailment events and have a steep set up cost, irrespective of the number of participating homes. When Yukon Energy deploys the program, this should be alleviated by the Direct install approach. Direct install programs maximize program participation because people do not need to invest time or money to benefit. While the program cost is higher with a direct install approach compared with BYOD and DIY programs, it is a simpler program to explain and operate.

The participants will be afforded the option to override the YEC's control over their devices and opt-out from curtailment events (temporary opt out.) A more detailed program design can determine how the YEC would like to manage the opt-out process. The DRMS system will provide the utility with data to confirm participation in events. Typically, participants have a limited number of times they can hit the override button if they want to receive their incentive (reward), yet the experience has shown that few of them surpass the limit.

3.1.4 Eligible Technologies and Measures

Web Connected Thermostats – Line Voltage & Central Air Thermostats

Thermostat measures proposed for the DLC program will target participants who have central electric heating systems or who have electric baseboard heating. DLC programs are ubiquitous in North America although most of them focus on air conditioning. Nevertheless, winter-peaking DLC programs are attracting a growing interest in Canada, with a number of pilot programs surveyed through our jurisdictional scan with successful outcomes.

The program being envisioned would have YEC acquire customers through promotion and outreach, directly install the devices free of charge and connect to participating customer devices onto the DRMS system. Thermostat measures offer a number of benefits to participants, such as the convenience of remote control, aesthetics, and they are a new "connected home" technology that categories of customers are attracted by, so the incentive offered can be modest. Program evaluations suggest that minimal impacts on applicant comfort are reported and that program abandonment rates are low even in absence of the monthly incentives. All participants will be offered to override DR events, albeit only the one on-going event. There are a number of override approaches, particularly in case of baseboard thermostats; some of them would minimally impact curtailment potential.

Line-voltage communicating thermostats (LVCTs) are programmable, connected thermostats that can control electric resistance baseboard heaters. These thermostats can replace bi-metallic or simple electronic thermostats and offer a more sophisticated method of control as compared to load control modules used to cycle baseboard heaters. The connected models being envisioned for the program are able to connect to a centralized DRMS system, with some models also having the capability to sense occupancy (using geolocation), or use outdoor weather conditions to adjust temperature as needed.

For the purpose of demand response, line voltage thermostats heating load can be curtailed by the utility through a number of strategies (pre-heating, on/off cycling, temperature setbacks, or even modulating the baseboards heat emission) which would need to be tested through the program along with, perhaps, optimization algorithms to lengthen the peak curtailment for the fleet of devices, as well as delaying and pacing the snapback (i.e. when the heating equipment need to catch up).

LVCTs are a technology recently introduced to the market that will allow homes employing electric baseboard heaters to realize the same benefits offered to centrally heated homes over the past several years through the use of popular web-enabled thermostats such as NEST and EcoBee. The capabilities of LVCTs go beyond that of a standard line-voltage programmable thermostat, essentially because of the "communicating" attribute.

Domestic Hot Water Heater Controllers

The two types of electric water heater controls being considered for this program are instrumented and non-instrumented. These are controller-only options that can be installed on a retrofit basis (i.e. they don't require replacing the tank).

The non-instrumented option consists of the use of an electrical load controller for an individual water heater, and as such this option is more limited in functionality (ie. on/off control with a solid state relay). In the case of an instrumented water heater, the DHW control approach is more sophisticated and involves temperature reading that allows the control system to prevent the water temperature level for a DHW tank to decrease below a certain threshold value. As such, the curtailment strategy can be more aggressive because the system prevents shortage of hot water. In this scenario, while most water heaters would switch off at the start of a DR event, a number of water heaters would start to switch back on during the event as that temperature threshold is crossed.

The proposed measures under this program with projected participation levels are presented below:

Exhibit 8: Measure Level Participation Projections

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9
YEC0283	Central Air Web Enabled Thermostats - Residential	per dwelling	-	15	14	19	17	16	-	-	-
YEC0306	DHW Control - Instrumented	per control system	200	239	236	332	322	313	-	-	-
YEC0282	Line Voltage Connected Thermostats - Residential	per dwelling	250	215	204	278	257	237	-	-	-

YEC030 7	DHW Control - Non-Instrumented	per control system	200	239	236	332	322	313	-	-	-

3.1.5 Impact, Budget and Cost Effectiveness

The projections, savings targets, and budgets presented below have been used for planning purposes. Initial budget levels are set based on conservative estimates of participation given the current market. However, the Utility reserves the right to adjust all assumptions as necessary in accordance with current market conditions, EM&V results, and program implementation experience; consequently, actual results may differ than those presented below.

Exhibit 9: Program Estimated Net Savings – Generator Level

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
Net kW Savings:	868	1,764	2,627	3,820	4,945	6,009	6,009	6,009	6,009

Based on the above, there is a cumulative net savings potential of 6 MW by the end of year 6, which continues, assuming no drop offs and no new participants.

Exhibit 10: Program Budget Summary (in $1,000)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Total
Incentive:	$472	$509	$495	$688	$656	$626	$0	$0	$0	$3,446
Non-Incen:	$457	$330	$291	$342	$346	$318	$10	$10	$10	$2,113
YEC:	$100	$63	$36	$33	$31	$29	$0	$0	$0	$293
Total:	$1,029	$902	$822	$1,063	$1,033	$973	$10	$10	$10	$5,852

Note, the incentive cost value above includes the direct install costs and the per device DRMS costs. The YEC staff costs are shared across all programs in the portfolio in a given year.

The cost-effectiveness test results shown were computed based on the assumptions regarding the level of incentive, budget, and projections. They are used for planning purposes. However, the Utility reserves the right to adjust all assumptions as necessary in accordance with current market conditions, EM&V results, and program implementation experience; consequently, actual results may differ than those presented below.

Exhibit 11: Program Level Cost-Effectiveness Results

	TRC	UCT	PC	RIM	Levelized Cost ($/kW) – Meter Level

Year 1	1.2	1.7	0.5	1.7	$133
Year 2	1.3	1.8	0.6	1.8	$111
Year 3	1.3	1.9	0.6	1.9	$105

3.1.6 Tracking, QA/QC and EM&V

The program implementer will conduct impact analysis on the ground of the DRMS platform data. Additional monitoring devices and equipment are not necessary, as the data from the devices (runtime, setpoint and actual room temperature, and perhaps other pieces of valuable information) will be accessible through the DRMS platform. A short, annual evaluation report memorializing the impact evaluation approach will be produced after the first heating season including lessons learned from implementation personnel, and recommendations for changes required before the next heating season. It is expected that, among other lessons learned, the annual evaluation report will comment on the adequacy of the technologies employed and alternative options to improve the program, as well customer experiences with the program including customer acceptance and willingness to participate in DR events and common issue/concerns noted by customers. YEC will hire a third-party EM&V contractor to certify the annual evaluation results. The scope of the third-party evaluator is doing a desk review of the impact assessment methodology and results, review the challenges and lessons learned by YEC and the implementer, and discuss and debate possible solutions for sake of continuous improvement of the suite of programs. YEC will seek to reach the right balance between scaling third-party EM&V down to what is appropriate for a jurisdiction like Yukon; and ensuring rigor and continuous improvement.

3.2 Customer Product Coupons

Non-Dispatchable Capacity & Energy Savings

3.2.1 Program Description

Customer Product Coupons is a residential lighting & appliance program, a common type of DSM program, that will encourage the sale/purchase and installation of energy efficient products sold in retail store and self-installed by participants in their homes. Shoppers can conveniently purchase high quality (e.g. ENERGY STAR or better) discounted products at retail locations.

The program proposes the coupon method of fulfilling incentives. Coupons can be distributed in-store, through bill inserts, or directly by program staff to customers. Customers / participants will use coupons at the cash register to redeem the rebate at the point of purchase. Coupons will be used for products with a lower price point and smaller rebates. For the larger rebates (e.g. three element water heater, solar spa pre-heat, and heat pump spa heaters) YEC will work with local suppliers and installers to promote the coupons and ensure the rebate is listed on the participating customer's invoice.

There is no duplication between the proposed Customer Products Coupon Program and the Energy Branch's Good Energy Program. Different residential measures are eligible for each of the programs. For example, the Energy Star appliances eligible for rebates in the Good Energy Program are excluded from the coupon program. Also, the Energy Branch currently does not offer any coupon programs. As per the current Energy Branch process,[7] shoppers are asked to mail-in their appliance rebate application and required documentation (itemized receipts and ENERGY STAR documentation) to receive the rebate cheque later delivered by mail.

ICF proposes the use of a commercial coupon processor for smaller consumer goods, such as lighting. In the previous inCharge program for residential lighting and block heater timers, customers filled out a participation form at the cash register or online. Rebates were fulfilled by utility staff as a credit on their next electricity bill. A commercial rebate processor can do this faster, at a lower cost, and with a better level of services leading to higher customer satisfaction with the program.

Program-related marketing is key to achieving meaningful results from a residential lighting & appliance program. The marketing campaign will entail: media buys with local media outlets, point of purchase marketing materials, bill inserts, website posting, and possibly direct customer engagement in stores (i.e. retail events.) Participating retailers – which benefit from the program through increased sales -- will be required to use merchandizing techniques to promote the products being rebated by the program. YEC will deliver sales staff training to make sure they are ready to inform customers about the benefits of eligible products. YEC will request that participating retailers co-promote the Program through their own marketing means.

Rebates are going to be eligible on a year-round basis, but the program administrator along with retailers will launch surges in marketing particularly in the spring and in the fall, when the sales of appliances and lighting are at their highest.

[7] Incentives for Appliances, Heating Systems & Water Conservation. Good Energy Yukon. 2019. Available at: http://goodenergyyukon.ca/appliances

3.2.2 Target Market

The coupon program will target all shoppers purchasing eligible products both in participating retail stores and non-participating retail stores. The main target for the program is the residential sector but as is common in residential lighting and appliance programs, some small commercial customers may participate because they too are shopping in retail stores. This is typically tolerated by most utilities running instant rebate or coupon programs because seeking to control eligibility based on rate class is particularly onerous and an unnecessary burden.

3.2.3 Approach to Implementation

YEC will act as the program administrator. YEC will exclusively fund incentives toward electricity conservation measures. YEC will engage with local retailers to deliver the program. Participating retailers are required to contribute to the delivery of the program through redeeming the coupons, as well as though joint promotion in flyers and media buys in local media outlets, installing point-of-purchase marketing materials provided by YEC and through the use merchandizing to encourage the purchase of energy efficient products. Retailers are also required to speak with third-party EM&V contractors during evaluation. YEC will lead the marketing and develop marketing materials including but not limited to the point-of-purchase materials. YEC will procure incentive fulfillment services (coupon processor) and the services of an energy efficiency consultant to help with analytics related with the Program, as well as the third-party EM&V contractor.

YEC will collaborate with community partners, such as the Yukon Conservation Society, for additional customer outreach and marketing.

3.2.4 Eligible Technologies and Measures

The proposed initial measures, incentive levels, and projected participation levels are presented below:

Exhibit 12: Initial Measures List with Incentive Levels

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0021	Battery Blanket Timers	per unit	$5
YEC0022	Hot Tub Covers	per unit	$5
YEC0023	Spot or Task Lighting	per unit	$30
YEC0026	ENERGY STAR® Dehumidifier - <= 25 pints/day	per unit	$20
YEC0027	ENERGY STAR® Dehumidifier >25 to <= 35 pints/day	per unit	$30
YEC0028	ENERGY STAR® Dehumidifier >35 to <= 45 pints/day	per unit	$30
YEC0029	Three Element Water Heater	per unit	$30
YEC0031	Spa Pumps Timers	per unit	$120
YEC0032	Solar Spa Pre-heat	per unit	$5
YEC0033	Heat Pump Spa Heaters	per unit	$625
YEC0034	Indoor Motion Sensors/Dimmer Switch/Timers (Hard-Wired)	per unit	$940
YEC0071	Instant Rebate- Web-enabled Advanced Thermostat - Central Air Furnace	per unit	$10

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0072	ENERGY STAR® Qualified LED Bulbs – General Purpose LED <= 60W	per unit	$105
YEC0074	ENERGY STAR® Qualified LED Bulbs – Specialty LED	per bulb	$1
YEC0075	ENERGY STAR® Qualified Indoor Light Fixture – Hard wired	per bulb	$5
YEC0076	Clotheslines	per bulb	$10
YEC0077	Heavy Duty Plug-In Timers	per unit	$25
YEC0078	Power Bar With Integrated Timer / Auto Shut-Off	per unit	$15
YEC0079	Water Heater Blanket	per unit	$10
YEC0080	ENERGY STAR® Qualified LED Bulbs – Specialty – 3 way bulbs	per unit	$20
YEC0081	ENERGY STAR® Qualified LED Bulbs – Specialty – Candle bulbs	per unit	$5
YEC0082	ENERGY STAR® Qualified LED Bulbs – Specialty – Flood/Reflector Bulbs	per unit	$2
YEC0083	ENERGY STAR® Qualified LED Bulbs – Specialty – Globe Bulbs	per unit	$5
YEC0084	ENERGY STAR® Ceiling Fan	per unit	$5
YEC0085	Weatherstripping (Door Frame)	per unit	$20
YEC0086	Weatherstripping (Foam Or V-Strip)	per unit	$10
YEC0087	ENERGY STAR Ceiling Fan	per unit	$5
YEC0099	ENERGY STAR Water Dispenser (Hot & Cold combination)	per unit	$20
YEC0302	ENERGY STAR Ventilation Fans	per unit	$10
YEC0303	Hot Tub Pump Timers	per unit	$20

Exhibit 13: Measure Level Participation Projections

Measure Code	Measure Name	Unit	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9
YEC0021	Hot Tub Pump Timers	per unit	-	14	14	14	14	14	14	14	14
YEC0022	Battery Blanket Timers	per unit	-	218	218	175	175	175	175	175	175
YEC0023	Hot Tub Covers	per unit	-	14	14	14	14	14	14	14	14
YEC0026	Spot or Task Lighting	per unit	-	22	20	16	16	16	16	16	16
YEC0027	ENERGY STAR® Dehumidifier – <= 25 pints/day	per unit	-	10	10	8	8	8	8	8	8
YEC0028	ENERGY STAR® Dehumidifier >25 to <= 35 pints/day	per unit	-	4	4	4	4	4	4	4	4

Measure Code	Measure Name	Unit	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9
YEC0029	ENERGY STAR® Dehumidifier >35 to <= 45 pints/day	per unit	–	1	1	1	1	1	1	1	1
YEC0031	Three Element Water Heater	per unit	–	22	22	18	18	18	18	18	18
YEC0032	Spa Pumps Timers	per unit	–	9	9	7	7	7	7	7	7
YEC0033	Solar Spa Pre-heat	per unit	–	2	3	3	3	3	3	3	3
YEC0034	Heat Pump Spa Heaters	per unit	–	9	9	9	9	9	9	9	9
YEC0071	Indoor Motion Sensors/Dimmer Switch/Timers (Hard-Wired)	per unit	–	54	114	134	134	134	134	134	134
YEC0072	Instant Rebate- Web-enabled Advanced Thermostat - Central Air Furnace	per unit	–	5	5	5	5	5	5	5	5
YEC0074	ENERGY STAR® Qualified LED BULBS - General Purpose LED <= 60W	per bulb	–	2,763	5,870	6,945	6,945	6,945	–	–	–
YEC0075	ENERGY STAR® Qualified LED BULBS - Specialty LED	per bulb	–	113	240	283	283	283	–	–	–
YEC0076	ENERGY STAR® Qualified Indoor Light Fixture - Hard wired	per bulb	–	124	263	311	311	311	–	–	–
YEC0077	Clotheslines	per unit	–	25	52	61	61	61	–	–	–
YEC0078	Heavy Duty Plug-In Timers	per unit	–	21	45	53	53	53	53	53	53
YEC0079	Power Bar With Integrated Timer / Auto Shut-Off	per unit	–	57	120	142	142	142	142	142	142
YEC0080	Water Heater Blanket	per unit	–	2	4	4	4	4	4	4	4
YEC0081	ENERGY STAR® Qualified LED Bulbs - Specialty - 3 way bulbs	per unit	–	1,084	2,302	2,724	2,724	2,724	–	–	–
YEC0082	ENERGY STAR® Qualified LED Bulbs - Specialty - Candle bulbs	per unit	–	217	461	545	545	545	–	–	–
YEC0083	ENERGY STAR® Qualified LED Bulbs - Specialty - Flood/Reflector Bulbs	per unit	–	217	461	545	545	545	–	–	–

Measure Code	Measure Name	Unit	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9
YEC0084	ENERGY STAR® Qualified LED Bulbs - Specialty - Globe Bulbs	per unit	-	217	461	545	545	545	-	-	-
YEC0085	ENERGY STAR® Ceiling Fan	per unit	-	22	46	55	55	55	55	55	55
YEC0086	Weatherstripping (Door Frame)	per unit	-	18	37	44	44	44	44	44	44
YEC0087	Weatherstripping (Foam Or V-Strip)	per unit	-	18	37	44	44	44	44	44	44
YEC0099	ENERGY STAR Ceiling Fan	per unit	-	7	14	17	17	17	17	17	17
YEC0302	ENERGY STAR Water Dispenser (Hot & Cold combination)	per unit	-	211	211	169	169	169	169	169	169
YEC0303	ENERGY STAR Ventilation Fans	per unit	-	211	211	169	169	169	169	169	169

The measure level assumptions are provided in the cost-effectiveness model.

3.2.5 Impact, Budget and Cost Effectiveness

The projections, savings targets, and budgets presented below have been used for planning purposes. Initial budget levels are set based on conservative estimates of participation given the current market. However, the Utility reserves the right to adjust all assumptions as necessary in accordance with current market conditions, EM&V results, and program implementation experience; consequently, actual results may differ than those presented below.

Exhibit 14: Program Estimated Net Savings

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
Lifetime MWh:	0	3,499	5,181	5,683	5,683	5,683	2,353	2,353	2,353
Annual MWh:	0	290	400	432	432	432	214	214	214
Cumulative Net kW Savings - Generator Level:	0	68	149	232	314	397	458	519	580
Net Annual kW - Meter Level:	0	62	73	76	76	76	55	55	55

Based on the above, there is a cumulative net savings potential of 0.5 MW by the end of year 8.

Exhibit 15: Program Budget Summary (in $1,000)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Total
Incentive:	$0	$37	$55	$59	$59	$59	$26	$26	$26	$347
Non-Incen:	$0	$90	$44	$40	$41	$40	$38	$38	$38	$371
YEC:	$0	$5	$4	$3	$3	$3	$2	$2	$3	$23
Total:	$0	$132	$103	$102	$103	$102	$66	$66	$67	$741

Note, the YEC staff costs are shared across all programs in the portfolio in a given year.

The cost-effectiveness test results shown were computed based on the assumptions regarding the level of incentive, budget, and projections. They are used for planning purposes. However, the Utility reserves the right to adjust all assumptions as necessary in accordance with current market conditions, EM&V results, and program implementation experience; consequently, actual results may differ than those presented below.

Exhibit 16: Program Level Cost-Effectiveness Results

	TRC	UCT	PC	RIM	Levelized Cost ($/kWh) – Meter Level	Levelized Cost ($/kW) – Meter Level
Year 3	1.6	2.5	4.8	0.5	$0.02	$134

3.2.6 Tracking, QA/QC and EM&V

YEC will work with the commercial coupons processor to generate reports used to track rebates that were fulfilled, for what products, when and from which retailers. Activities logged by the processor will be logged in the tracking system and used to generate savings reports – including redeemed coupons, sent and cashed cheques, and reconciliation account logs. The program administrator will use a deemed savings approach to perform impact evaluation, and track deemed savings in the database.

As a form of QA/QC, the program administrator will deliver retail store sales staff training. The program administrator will also conduct mystery shopper visits to observe compliance with program rules that retailers are asked to follow, specifically related to merchandizing and use of point-of-purchase marketing materials. Finally, YEC is responsible for the careful review of incentive fulfillment reports sent by the coupon processor.

A third-party EM&V contractor will be hired to inspect that program rules and operation procedures are being adhered to by YEC, and that the deemed savings calculations and their attribution to the program are rigorous and sound. Both program administrators and the marketing coupon processors will have to submit their operational manuals and procedures for third-party EM&V review.

3.3 Dual Fuel Demand Management

Dispatchable or Non-Dispatchable Capacity

3.3.1 Program Description

With growing emphasis on electrification of home heating systems to reach Yukon and federal decarbonization targets, residents are being encouraged to upgrade their home heating systems with cold-climate heat pumps. The Energy Branch is offering rebates of 40% of eligible heat pump costs up to a maximum of $8,000 and has a target to replace 1,300 residential fossil fuel heating systems with "smart electric heating systems" by 2030.[8] While heat pumps are a highly efficient means to heat and cool homes, when the outside temperature dips below its operating threshold the heat pump relies on an auxiliary heating system – typically in-duct electric coils. This would create significant additional demand during the peak period.

ICF recommends a dual fuel program modeled after the long-standing program offered by Hydro Quebec, called Rate DT.[9] Participants receive a direct-installed dual fuel demand management switch to automatically switch from the heat pump to the fuel-burning forced-air system, when the outdoor air temperature drops below a threshold. Instead of a modified rate (as provided by Hydro Quebec in Rate DT), ICF recommends offering an on-bill performance incentive to participants for reducing their electricity consumption during peak periods. Initial sign-on incentives should also cover the cost of any upgrades required to the fossil fuel heating system (e.g. new heating oil tank) to ensure that the system is safe to continue operating.

YEC will need to collaborate with the Energy Branch, such that participants in the Good Energy Heating System Rebate program are advised to keep their fossil fuel heating system and coordinate their heat pump installation with their enrollment in the Dual Fuel Demand Management program.

3.3.2 Target Market

The target market for the Dual Fuel program includes the YEC's residential customers with that use electricity as a primary source of heating and a fuel as the auxiliary source. The target audience will be participants of the Energy Branch's Good Energy rebates for cold climate air-source heat pumps who retain their fuel-burning heating system as a back-up.

3.3.3 Approach to Implementation

The recommended approach for the Dual Fuel Program is a 'direct install' program. Under this program model, incentives are provided to cover a substantial portion of the capital cost of measures, often entirely. 'Turn-key' installation of the measures is performed by sub-contractors working on behalf of the utility or through a utility-approved contractor network. A performance incentive is provided for ongoing participation, to boost persistence of participation in the program. Ideally the annual incentive would be provided to participants in the form of an on-bill credit so that they easily associate the bill savings to the program and their energy costs.

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[8] Government of Yukon, *Our Clean Future*, 2020 < https://yukon.ca/sites/yukon.ca/files/env/env-our-clean-future.pdf>

[9] Hydro Quebec, 'Rate DT – Dual Energy' < https://www.hydroquebec.com/residential/customer-space/rates/rate-dt.html >

3.3.4 Eligible Technologies and Measures

The Energy Branch currently offers rebates for ducted cold climate air-source heat pumps for existing and new homes. The goal of this proposed offering is to manage the heating loads from these new heat pumps and their auxiliary heating systems to curtail any electric load during peak periods. This is particularly important because even cold climate heat pumps rely on electric resistance heaters on the coldest days when the outdoor temperature exceeds the heat pump's minimum threshold, and these temperatures directly line up with peak periods in the Yukon.

A dual fuel demand management switch automatically switches from the heat pump to the fuel-burning forced-air system, based on outdoor air temperature. Hydro Quebec offers a similar program, called Rate DT.[10]

An HVAC contractor would upgrade the fuel furnace, as required, provide a thermostat (it does not need to be 'smart' or communicating), a relay to shut down the heat pump, a PLC controlling the relay, and low-voltage control wiring from the PLC to the meter. YEC will need to replace the existing meter with an interval meter with a built-in temperature sensor.

The projected participation levels are presented below, and are based on a portion of the Energy Branch residential heat pump installation targets:

Exhibit 17: Measure Level Participation Projections

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9
YEC0309	Dual Fuel DR Switch - Residential	per unit	-	37	91	109	109	109	109	113	-

3.3.5 Impact, Budget, and Cost Effectiveness

The projections, savings targets, and budgets presented below have been used for planning purposes. Initial budget levels are set based on conservative estimates of participation given the current market. However, the Utility reserves the right to adjust all assumptions as necessary in accordance with current market conditions, EM&V results, and program implementation experience; consequently, actual results may differ than those presented below.

Exhibit 18: Program Estimated Net Savings – Generator Level

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
Net kW Savings:	0	272	940	1,741	2,542	3,343	4,143	4,974	4,974

Based on the above, there is a cumulative net savings potential of almost 5 MW by the end of year 8, which continues, assuming no drop offs and no new participants.

[10] Hydro Quebec, 'Rate DT – Dual Energy' < https://www.hydroquebec.com/residential/customer-space/rates/rate-dt.html >

Exhibit 19: Program Budget Summary (in $1,000)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Total
Incentive:	$0	$263	$648	$776	$776	$776	$776	$805	$0	$4,820
Non-Incen:	$0	$191	$167	$128	$147	$126	$136	$134	$10	$1,040
YEC:	$0	$33	$48	$38	$37	$36	$49	$47	$0	$287
Total:	$0	$487	$863	$942	$960	$938	$961	$986	$10	$6,147

Note, the incentive cost value above includes the entire direct install costs and consider costs of upgrades to the back-up fossil fuel heating system. The YEC staff costs are shared across all programs in the portfolio in a given year.

The cost-effectiveness test results shown were computed based on the assumptions regarding the level of incentive, budget, and projections. They are used for planning purposes. However, the Utility reserves the right to adjust all assumptions as necessary in accordance with current market conditions, EM&V results, and program implementation experience; consequently, actual results may differ than those presented below.

Exhibit 20: Program Level Cost-Effectiveness Results

	TRC	UCT	PC	RIM	Levelized Cost ($/kW) – Meter Level
Year 1	NA	NA	NA	NA	NA
Year 2	1.5	1.3	1.3	1.3	$167
Year 3	1.9	1.6	1.3	1.6	$120

3.3.6 Tracking, QA/QC and EM&V

The program implementer will conduct impact analysis on the ground of the interval meter data from participants and weather data. A short, annual evaluation report memorializing the impact evaluation approach will be produced after the first heating season including lessons learned from implementation personnel, and recommendations for changes required before the next heating season. It is expected that, among other lessons learned, the annual evaluation report will comment on the adequacy of the technologies employed and alternative options to improve the program, as well customer experiences with the program and common issues/concerns noted by customers. YEC will hire a third-party EM&V contractor to certify the annual evaluation results. The scope of the third-party evaluator is doing a desk review of the impact assessment methodology and results, review the challenges and lessons learned by YEC and the implementer, and discuss and debate possible solutions for sake of continuous improvement of the suite of programs. YEC will seek to reach the right balance between scaling third-party EM&V down to what is appropriate for a jurisdiction like Yukon; and ensuring rigor and continuous improvement.

3.4 Demand Response EV Charging

Dispatchable Capacity

3.4.1 Program Description

The proposed Demand Response electric vehicle (EV) Charging program is a load management program for EV owners. It can offer financial incentives through on-bill rebates to encourage off-peak EV charging and can even include a 'direct load control' (DLC) component that would allow the YEC to remotely start and stop curtailment events by sending communication signals to a vehicle or charger.

There is no duplication between the proposed DR EV Charging Program and the Energy Branch's Good Energy Program. The Energy Branch does not offer any demand management programs.

The Energy Branch is currently offering incentives for a variety of electric vehicles as well as level 2 chargers. As a result, an in-vehicle control device is recommended, as it is agnostic to the type of vehicle and charger, as well as the location of the charger. Alternatively, the networked chargers can be enrolled and connected to the utility's DRMS. The program is built to test the reliability and duration of the curtailment that can be achieved. It is an opt-in program; only EV owners that want to manage their charging activities and are willing to have their equipment controlled by the utility during peak periods enroll. The participants do not pay for the controlled devices.

ICF recommends that YEC collaborate with local car dealerships and the Energy Branch, such that participants in the Clean Transportation Rebate program are advised to enroll in the Demand Response EV program.

Customers may have concerns that utility managed charging could lead to circumstances where their vehicle does not have the adequate charge to make it to their destination. The participants will be afforded the option to override the YEC's control over their devices and opt-out from curtailment events (temporary opt out). A more detailed program design can determine how the YEC would like to manage the opt-out process.

3.4.2 Target Market

The target market for EV Charging Program includes the YEC's residential customers that own an electric vehicle but could also be extended to commercial and institutional customers. All participants must be customers located on the Yukon Integrated System with an active electricity account, and they must agree to participate in curtailment events. Participants may be offered to "override" specific events from time to time, so long as the override is not systematic. Empirical evidence has shown that the ability to override improve greatly how palatable the programs are to customers, yet participants override events relatively rarely.

3.4.3 Approach to Implementation

Utilities can offer direct load control (DLC) managed charging via the charging device or through an in-vehicle device.

Many utilities are beginning to offer DLC via charger pilots and programs – in most cases, they provide a rebate for eligible charging stations that are managed-charging capable. Given that the Energy Branch is already offering incentives for residential and commercial Level 2 chargers, YEC will just need to ensure compatibility with its DRMS for managed charging when recruiting participants. Much like the proposed Dual Fuel Demand Response program, performance incentives should be provided for participating in DR curtailment events. Ideally the incentive would be provided to participants in the form of an on-bill credit so that they easily associate the bill savings to the program and their energy costs.

A few relevant examples of utility-run managed charging programs include Sonoma Clean Power and Massachusetts Municipal Wholesale Electric Company. Sonoma Clean Power in California offers a $5 monthly bill credit, subsidized charger, and a sign-on rebate to participants in their GridSavvy demand response program. GridSavvy uses the JuiceNet app and dashboard to manage charging. Massachusetts Municipal Wholesale Electric Company provides participants with a rebate for a Level 2 charger, and automatically enroll them in a scheduled charging program that aligns with the utility's time of use rate. It also enrolls the participant in an emergency scheduling program to curtail charging during peak hours.

An example of an in-vehicle EV Charging Program is the SmartCharge Rewards Program offered by Geotab, and delivered in a number of jurisdictions including Portland, Georgia, Florida, New York, Nashville, and Tacoma. Through this offering, the participant receives an online SmartCharge Rewards account, and a free device that they can easily plug into their vehicle themselves. The application rewards the participant for off-peak charging, while the on-board telematics collect valuable data for YEC on EV charging and driving habits and statistics. There is the also the option of direct load control, where YEC can trigger curtailment events.

3.4.4 Eligible Technologies and Measures

Active managed EV charging (or direct load control) relies on communication signals from the utility to be sent to a vehicle or charger to control charging. There are a variety of network communication interface options between the utility and the charger or EV, including Wi-Fi, cellular broadband, and FM radio broadcast. Most Level 2 chargers are networked and therefore can communicate with software systems that manage a charging network, however compatibility between YEC's selected DRMS and the vehicles and chargers being promoted through the Energy Branch's Clean Transportation Rebate program will need to be considered in the detailed design for this program.

The projected participation levels are presented below and are based on a portion of the Energy Branch's EV targets:

Exhibit 21: Measure Level Participation Projections

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9
YEC0308	EV managed charging	per unit	-	-	100	140	188	242	302	368	440

3.4.5 Impact, Budget and Cost Effectiveness

The projections, savings targets, and budgets presented below have been used for planning purposes. Initial budget levels are set based on estimates of participation as a proportion of the Energy Branch EV sales targets. However, the Utility reserves the right to adjust all assumptions as necessary in accordance with current market conditions, EM&V results, and program implementation experience; consequently, actual results may differ than those presented below.

Exhibit 22: Program Estimated Net Savings – Generator Level

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
Net kW Savings:	0	0	486	1,166	2,079	3,254	4,721	6,509	8,646

Based on the above, there is a cumulative net savings potential of 8.6 MW by the end of year 8, which continues, assuming no drop offs and no new participants.

Exhibit 23: Program Budget Summary (in $1,000)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Total
Incentive:	$0	$0	$162	$227	$305	$392	$489	$596	$713	$2,884
Non-Incen:	$0	$0	$190	$88	$121	$144	$183	$215	$293	$1,234
YEC:	$0	$0	$12	$11	$15	$18	$31	$35	$69	$191
Total:	$0	$0	$364	$326	$441	$554	$703	$846	$1,075	$4,309

Note, the YEC staff costs are shared across all programs in the portfolio in a given year.

The cost-effectiveness test results shown were computed based on the assumptions regarding the level of incentive, budget, and projections. They are used for planning purposes. However, the Utility reserves the right to adjust all assumptions as necessary in accordance with current market conditions, EM&V results, and program implementation experience; consequently, actual results may differ than those presented below.

Exhibit 24: Program Level Cost-Effectiveness Results

	TRC	UCT	PC	RIM	Levelized Cost ($/kW) – Meter Level
Year 3	1.8	1.3	2.7	1.3	$180
Year 4	2.5	1.6	2.7	1.6	$115
Year 5	2.8	1.7	2.7	1.7	$116

3.4.6 Tracking, QA/QC and EM&V

The program implementer will conduct impact analysis on the ground of the DRMS platform data. Additional monitoring devices and equipment are not necessary, as the data from the devices will be accessible through the DRMS platform. A short, annual evaluation report memorializing the impact evaluation approach will be produced after the first peak season including lessons learned from implementation personnel, and recommendations for changes required before the next peak season. It is expected that, among other lessons learned, the annual evaluation report will comment on the adequacy of the technologies employed and alternative options to improve the program, as well customer experiences with the program including customer acceptance and willingness to participate in DR events and common issue/concerns noted by customers. YEC will hire a third-party EM&V contractor to certify the annual evaluation results. The scope of the third-party evaluator is doing a desk review of the impact assessment methodology and results, review the challenges and lessons learned by YEC and the implementer, and discuss and debate possible solutions for sake of continuous improvement of the suite of programs. YEC will seek to reach the right balance between scaling third-party EM&V down to what is appropriate for a jurisdiction like Yukon; and ensuring rigor and continuous improvement.

3.5 Commercial Demand Response

Dispatchable Capacity Program

3.5.1 Program Description

The proposed pilot is a commercial demand response (DR) program in governmental and non-governmental general service buildings based on the two the following DR strategies; 1) remote triggering (automatic or not) of embedded emergency diesel-fired generators; and/or 2) remote shedding of large commercial loads (e.g. large compressors, pumps, and fans systems) to reduce demand. Analysis suggests that emergency standby generators have the potential to provide greater capacity to the grid than load shedding, firstly because of the significant pre-existing installed capacity, but also because generators can run for duration that can last 12 hours or more, and thereby do not require shifting the load, and will not cause a snap back. As such, embedded gensets are anticipated to be the primary source of capacity made available by the program and should be the main target for the program. Later, after successful deployment remote control of embedded generators, other loads that could potentially be curtailed entail refrigeration compressors at local food retail stores and ice rinks.

There is no duplication between the proposed Commercial Demand Response Pilot Program and the Energy Branch's Good Energy Program. The Energy Branch does not offer any demand response programs.

The program will target participants with on-site generators (used for emergency) that could be turned on remotely by the YEC to reduce the facilities' demand and, if large enough, feed excess power to the grid. YEC would remotely activate generators, either by contacting a facility manager to manually respond or by the use of a remote-control system. The solution is technically feasible in certain sites, will be resource-intensive yet is cost-effective because of the large curtailment potential per site. It will require proper considerations are made from the outset on a project-by-project basis, to ensure compliance with regulatory requirements and any technical or operational requirements, which are dependent on the participants' existing generator configuration, and the loads being served.

To understanding how a given facility and its standby generator would need to be reconfigured to enable participation in the program, the program administrator will require a feasibility study to further understand the participant's existing generator, switchgear, controls, and facility. The study will delineate what upgrades are necessary to facilitate interconnection between the facility and the grid and allow an engineer to design the interconnection specific to both the utility and participant's needs.

The participation process would begin by engaging potential participants to determine if their facilities are suitable candidates to participate in the program and, if so, encourage them to enrol. If a participant is willing to enroll, the YEC would conduct a pre-feasibility study to determine key information that would be used to qualify the facility for a more detailed assessment. Distributors of the technology required for each system would work with the participants to determine how to configure their facilities on a case-by-case basis, should a more detailed assessment be warranted, and develop a business case which outlines the system costs, technical configuration, energy and capacity that will be provided to the grid when the system is activated. This document would be used as the basis of informing the decision to proceed, for both the YEC and the participant.

The YEC established interconnection requirements, the IPP Interconnection Technical Requirements[11], for embedded generation resources. However, the interconnection requirements were meant to provide guidelines surrounding

[11] Yukon Energy Corporation, Independent Power Producers Interconnection Technical Requirements, retrieved from; https://yukonenergy.ca/media/site_documents/Yukon_Energy_Interconnection_Guide.pdf.

renewable energy projects, such as solar photovoltaic, many of which cannot provide firm capacity such as a commercial DR program. However, as the basis for a pilot-specific interconnection requirements document, the document provides some guidelines that should be followed in the participation process.

There are numerous configurations for controls and switchgear of generator based on current configuration and the size of the generator compared with the building load. All standby generator systems are currently configured so that they operate independently of the grid, sometimes after a brief interruption of services while the building operator manually operates the switchgear. At a minimum, all the switchgears of the participating facilities will have to be modified to ensure that there is no interruption to electricity services provided to the facility when the DR event gets triggered. Furthermore, if technically possible, YEC and the participant would benefit from running the generators constantly and at their best efficiency point (approximately 75-80%) thorough the entire DR event. An ideal switchgear system, if the space and pre-existing genset allows it, would enable the genset constantly during the DR event, supplying excess power to the grid if the building demand is lower than the generator's supply, and feeding from the grid when the building demand is higher than the generator's supply. Each participant would present unique technical requirements, as it relates to the switchgear and technical configurations of the systems, as well as different levels of compensation to the participant to make them whole for enabling access to the generator.

3.5.2 Target Market

All general services customers would be eligible for the program, however, the program marketing and engagement strategy would focus specifically on government buildings – educational facilities and community centres, for example. The aforementioned public sector facilities are known to have sizeable generators that would be large enough to justify including them in the program. Based on an assessment of peak electricity consumption in commercial market segments, few buildings are likely to have a generator with a nameplate capacity over 50kW, a conclusion that was corroborated by a local genset distributor. While the program would not exclude commercial (non-governmental) facilities, there is thought to be fewer buildings equipped with generators large enough to warrant the incremental technology cost that would enable them to participate.

3.5.3 Approach to Implementation

Yukon Energy would provide compensation to those that sign up into the program to match both the cost of upgrades to the generator so that they can be remotely triggered, in addition to the additional operation and maintenance cost associated with participating in the program. In Government facilities, compensation must match the cost (technology cost, labour and any other transaction cost) incurred by the participant, because government entities are precluded from incurring a profit through an incentive program. Should commercial facilities have an eligible generator, a capacity incentive payment would help to entice people to participate in addition to offsetting the operational costs. Because most participants are anticipated to be government customers and because of the need to match payment with actual anticipated costs for government buildings, compensation offered to the participant will have to be negotiated on a case-by-case basis.

The driver for government entities to participate in the program would entail:

- the ability to invest in enhanced control and switchgear systems and larger storage tanks which will have additional benefits,
- the ability to partially subsidized new hires that would look over their fleet of emergency generators,
- the spirit of acting for the greater good in Yukon, and against rate increase that would be caused by YEC having to invest in new diesel generators.

The functions of remote communication and remote control of the embedded generators, or load shedding of commercial loads, as well as verification and data acquisition will be performed by a commercial demand response management system (DRMS). When selecting the DRMS system in Year 1, it is important to consider the platform's experience and compatibility with controls for commercial-scale generators. Commercial DRMS providers provide pre-packaged control and communication gears. They typically provide support with the individual site pre-feasibility studies to provide technical guidance. Their pre-packaged controllers get installed near the controlled generators or load, and communicate with the cloud-based commercial DRMS interface through cell phone signal.

3.5.4 Eligible Technologies and Measures

Some additional key considerations during each individual feasibility study will include:

Facility Type and Criticality of Loads – Some types of facilities have critical loads (e.g. detention centres, hospitals), where participation in a commercial DR program may be viewed as adding excessive complexity and risk to their operations. While beyond the scope of this report, standby generation in these types of facilities is often regulated, certainly in the case of hospitals and detention centres. It is likely these regulations entail operational requirements that would conflict with, if not preclude, participation in the program.

Generator Specifications – The design of the control and switchgear upgrade would have to account for the characteristics of the existing generators. For instance, some standby generators are designed to modulate their throughput, while others cannot and simply run constantly. Some generators will be in better condition than others and potential candidate generators for program must be inspected prior to accepting participants as to avoid disputes about liability for generator malfunctions or breakdowns.

Furthermore, standby generators installed in buildings are designed for emergency circumstances and have limitations on the number of hours they can be operated. For example, the manufacturer warranty for standby generators may be breached if the units are operated for over 500 hours in a year. Fortunately, the program as envisioned now would solicit the generators far less than 500 hours per year.

Switchgear Upgrade Consideration – It is anticipated that for most participants generator controls and switchgear upgrades would be required to enable participation in the program because while all standby generators are equipped with controls designed to respond in the event of an outage; they are not designed to operate in conjunction with the utility grid as another supply source. The switchgear and control upgrade needed to participate in program depends on the current building, genset and control characteristics. The cost of control switchgear upgrade will differ drastically based on generator size and the desired configurations but can range from as low as $3,000 to as much as 30% of the generator cost for more complex configurations, which may make some projects unfeasible from an economic standpoint.[12]

Fuel Storage – The pilot will need to consider fuel tank storage capacity, refueling costs, and schedules, and compensate participants accordingly for costs incurred to participate in the program. Based on examination of Caterpillar models, typical storage tanks on smaller standby generators will provide backup power for approximately two to four hours depending on load. Other models, however, are equipped with storage tanks that can carry enough fuel to run for 24 hours at best performance point.[13] To overcome barriers associated to fuel storage, the YEC may consider funding the installation of additional fuel tank capacity on the participant's site. Another option would be to

[12] Price range was provided by a service provider that implements distributed generation technology platforms and is based on experience with similar types of projects in other jurisdictions.

[13] Caterpillar C3 Diesel Generator Sets, and C7 Tier4F Generator Sets Technical Specifications.

establish curtailment duration and capacity thresholds, that would ensure the DR event does not consume so much fuel that the facility is left without power if an emergency situation would immediately follow the DR event.

Regulatory Considerations – In the Yukon, air emissions permits would be required for a generator with a capacity of 1 megavolt ampere (MVA) or greater, or if a fuel with a sulfur content higher than 1.1% is used to produce electricity.[14] However, fuel used in small[15] (<1MW) stationary combustion engines that is imported or manufactured in Canada cannot exceed 15mg/kg, which is well below the threshold that requires an emissions permit.[16]

Measurement and Verification – In absence of advanced metering infrastructure, the YEC can install a dedicated metering system as part of the control and switchgear upgrade to quantify the energy that is produced by each unit during an event, thereby providing positive confirmation that the incremental generation actually happened when it was triggered.

The proposed initial measures and projected participation levels are presented below:

Exhibit 25: Measure Level Participation Projections

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9
YEC0293	Emergency Generation – Small (75 kW)	per control system	–	–	–	1	1	1	1	1	1
YEC0294	Emergency Generation – Med (150 kW)	per control system	–	–	–	2	3	3	3	3	3
YEC0295	Emergency Generation – Large (750 kW)	per control system	–	–	–	2	1	1	1	1	1

3.5.5 Impact, Budget and Cost Effectiveness

The projections, savings targets, and budgets presented below have been used for planning purposes. Initial budget levels are set based on conservative estimates of participation given the current market. However, the Utility reserves the right to adjust all assumptions as necessary in accordance with current market conditions, EM&V results, and program implementation experience; consequently, actual results may differ than those presented below.

Exhibit 26: Program Estimated Net Savings – Generator Level

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
Net kW Savings:	0	0	0	798	1,476	2,155	2,833	3,511	4,190

Based on the above, there is a cumulative net savings potential of 4 MW by the end of year 9.

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14 https://yukon.ca/en/doing-business/licensing/get-air-emissions-permit

15 Has a per-cylinder displacement of less than 30 000 cm3, approximately equivalent to a capacity of 1MW.

16 Government of Canada, Sulfur in Diesel Fuel Regulation, SOR/2002-254, 3(1)(f)

The budget below represents the costs for the control systems, DRMS device support fees, fuel tank, and diesel fuel costs, and all other building facility operator compensation as part of the "incentive" cost. Program administration costs and engineering feasibility study costs are part of the "non-incentive" utility cost, "Incentive" herein means compensation to the participants equal to the amount of the upgrade and transaction cost that they will be incurring. Note, the YEC staff costs are shared across all programs in the portfolio in a given year.

Exhibit 27: Program Budget Summary (in $1,000)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Total
Compensation to participant in lieu of incentive:	$0	$0	$0	$309	$289	$289	$289	$289	$289	$1,754
Non-Incen:	$0	$0	$0	$192	$46	$38	$43	$40	$56	$415
YEC:	$0	$0	$0	$15	$14	$14	$18	$17	$28	$106
Total:	$0	$0	$0	$516	$349	$341	$350	$346	$373	$2,275

The cost-effectiveness test results shown were computed based on assumptions regarding the level of incentive, budget, and projections. They are used for planning purposes. However, the Utility reserves the right to adjust all assumptions as necessary in accordance with current market conditions, EM&V results, and program implementation experience; consequently, actual results may differ than those presented below.

Exhibit 28: Program Level Cost-Effectiveness Results

	TRC	UCT	PC	RIM	Levelized Cost ($/kW) – Meter Level
Year 4	1.2	1.2	1.1	1.2	$192
Year 5	1.3	1.3	1.1	1.2	$152
Year 6	1.3	1.3	1.1	1.3	$149

The pilot would test enhanced load shedding capabilities, the YEC would be given remote monitoring and control, allowing commands to be sent which trigger the generators reduce or eliminate the participants building load during critical system peaks, supplanting the need to contact a facility operator to ask that they turn on their generator. A number of public sector facilities in the Yukon are equipped with standby generators that are used in the event of an outage/ to provide power to critical systems or entire building loads. The YEC should leverage key account relationships to further explore load shedding opportunities taking this approach. The solution is cost-effective. However, each facility will need to be assessed on a case-by-case basis to determine if the program is feasible for each participant.

3.5.6 Tracking, QA/QC and EM&V

The program implementer will conduct impact analysis on the ground of the DRMS platform data. Additional monitoring devices and equipment are not necessary, as the data from the devices will be accessible through the DRMS platform. A short, annual evaluation report memorializing the impact evaluation approach will be produced after the first peak season including lessons learned from implementation personnel, and recommendations for changes required before the next peak season. It is expected that, among other lessons learned, the annual evaluation report will comment on the adequacy of the technologies employed and alternative options to improve the program, as well customer experiences with the program including customer acceptance and willingness to participate in DR events and common issue/concerns noted by customers. YEC will hire a third-party EM&V contractor to certify the annual evaluation results. The scope of the third-party evaluator is doing a desk review of the impact assessment methodology and results, review the challenges and lessons learned by YEC and the implementer, and discuss and debate possible solutions for sake of continuous improvement of the suite of programs. YEC will seek to reach the right balance between scaling third-party EM&V down to what is appropriate for a jurisdiction like Yukon; and ensuring rigor and continuous improvement.

Appendix A Detailed Approach & Analysis

1 Scope 1 – DSM Program Design Approach

The following section outlines the approach and analysis of the Scope 1 DSM programs presented in the report.

1.1 Development of Program Options

As presented in Exhibit 2, a structured approach to the program design was utilized.

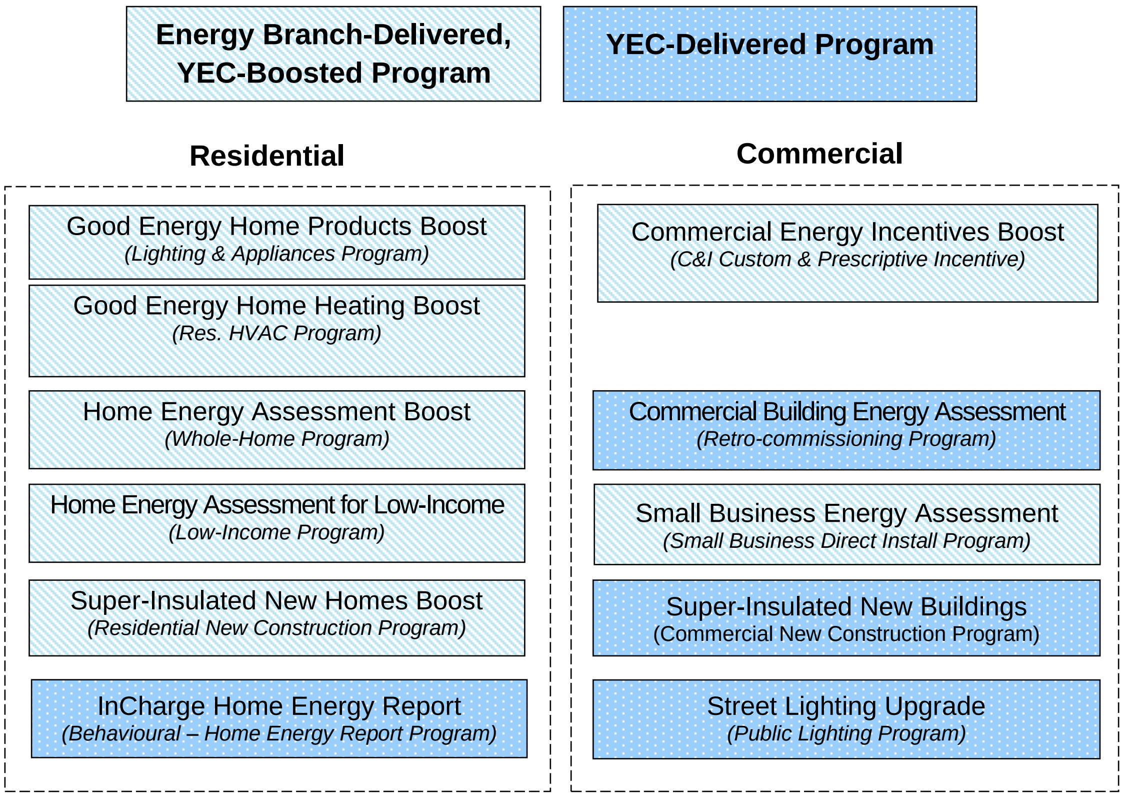
The initial program options list was developed beginning with a consideration for the current portfolio of DSM programs in the Yukon and identifying improvements or changes to the current programs. A gap analysis was conducted in which the current portfolio of programs in Yukon from both YEC and the Energy Branch were compared against each other and with ubiquitous programs found in a large number of jurisdictions.

ICF started by using a comprehensive typology of energy efficiency programs, which were screened based on the scope of work, their relevance to the Yukon territory, and ICF's best judgement. A preliminary set of twelve (12) programs were presented to the TAC in August 2018:

- R1. Whole-Home Program
- R2. Low-Income Program
- R3. Customer Product Rebates Program (Next Generation)
- R4. Residential Heating, Ventilation & DHW Program
- R5. Behavioural Program
- R6. Residential New Construction Program
- GS1. Commercial Retrofit Incentive Program
- GS2. Commercial Energy Audit and Technical Assistance Program
- GS3. Small Business Program
- GS4. Retro-Commissioning (RCx) Program
- GS5. Public Lighting
- GS6. Commercial New Construction Program

During the stakeholder consultation and screening phase of the program design, ICF conducted meetings with the technical advisory committee (TAC), including the Energy Branch, Yukon Conservation Society, Yukon Housing, and various contractors and suppliers. After consultations with the TAC and YEC, any programs considered irrelevant to Yukon were eliminated. The following programs were recommended under Scope 1:

Exhibit 29: Scope 1 Programs



In May 2021, YEC enlisted ICF to update the Program Design to address the Government of Yukon's February 2021 Order in Council, which:

- Requested the YUB to authorize YEC to recover reasonably incurred DSM program cost from rates.
- Requested the YUB to "consider the extent of any duplication between the program for which costs are incurred and a demand-side management program provided by the Government of Yukon or in which the Government of Yukon is a participant".[2]

ICF conducted an analysis of the current Energy Branch program offerings, proposed a variety of strategies to avoid duplication of program offerings (including some new proposed YEC program offerings), and revised the proposed scope of programs based on these recommendations.

The revised programs are presented in this report:

- R1. Residential Demand Response (New)
- R2. Customer Product Coupons (modified from "Good Energy Home Products Boost")
- R3. Dual Fuel Demand Response (New)
- R4. Demand Response EV Charging (New)
- GS1. Commercial Demand Response (New)

1.2 Measure Development & Characterization

The list of measures under each program were developed by drawing upon pre-existing measure lists and TRM documentation from other jurisdictions and was expanded upon to include energy efficiency measures from ICF's database, which includes measures ICF has included in previous electric conservation potential studies and program design studies.

ICF reviewed the input assumptions from various TRMs to identify any concerns with the measure characterization. Custom input assumptions were developed for certain new/emerging measures; these measures relied heavily on information from existing custom projects and data on emerging measures. This included technologies that are new to the market or that are commercially available but underused and expected to reach full commercialization during the study period, and technologies likely to emerge during the study period but that are not yet market-ready (for example, line voltage connected thermostats and three element water heaters).

The development of the measure list was an iterative process. ICF initially focused on the inclusion of measures with high DSM potential while keeping the program design relatively simple. The final list in 2018 contained over 300 residential and commercial sector measures across all programs. After re-evaluating the proposed measures with updated avoided costs and a focus on demand reduction, the prioritized programs presented in the body of the report consist of a much smaller number of measures that have a large impact on peak demand. A list of measures is provided under each program description in the main body of the report and full measure descriptions and input assumptions are available in the TRM documentation.

1.3 Technical Resource Manual (TRM)

A technical resource manual was developed for YEC to document the following measure level assumptions:

- Measure Code: Unique identifier for each measure
- Measure Name & Description
- Applicable Program Type
- Unit Definition: Savings are defined on a per unit basis (e.g. per lamp, per home)
- Baseline Description
- Measure Eligibility Criteria
- Applicable Load Profile
- Annual Consumption Savings (kWh)
- Peak Coincident Savings (kW)
- Incremental Technology Costs
- Effective Useful Life (EUL)

Measure input assumptions and parameters include incremental costs, electrical consumption savings (kWh), effective useful life, and classification into program types and end-use profiles for the determination of coincident peak savings. These assumptions should be revised periodically as new information becomes available.

Information on the cost of implementing each measure was compiled from secondary sources, including both the measure's full cost and incremental cost in comparison to baseline equipment. Other factors such as the increased cost of transportation or shipping of equipment to Yukon were taken into consideration with a locational adjustment factor. Some measures have operation and maintenance costs expected to reoccur over the lifetime of the measure, in this case the costs have been annualized based on the number of years of equipment life and the discount rate.

The incremental cost is applicable when a measure is installed in a new facility or at the end of its useful life in an existing facility; in this case, incremental cost is defined as the difference in cost between the energy efficient option relative to the "baseline" technology. The full cost is applicable when an operating piece of equipment is replaced with a more efficient model or a fuel choice option prior to the end of its useful life.

1.4 Cost-Effectiveness Tool

The individual measure level data from the TRM entries were aggregated into ICF's DSM cost-effectiveness tool. This cost effectiveness tool is a measure-based model which takes the measure characteristic data from the TRM and applies cost-effectiveness tests, avoided costs, GHG emission factors, and estimates of program participation and incentive levels to produce DSM portfolio projections at a program level.

The cost-effectiveness tool presents the following data on a measure-level and program level basis:

- Utility Level Avoided Energy Costs
- Total Lifetime Emission Savings (tonnes of CO_2)
- Utility Administrative Costs
- Cost-Effectiveness Test Results
- Total Resource Cost (TRC)
- Utility Cost Test (UCT)
- Ratepayer Impact (RIM)
- Cost of Abatement
- Annual Participation
- Incentive per unit

1.4.1 Avoided Costs

Avoided electricity supply resource costs consist of avoided energy costs and avoided capacity costs. The use of both types of avoided costs are discussed below.

1.4.1.1 Approach to Avoided Cost Modeling

The focus of DSM in the Yukon has shifted from a low-cost source of energy supply in 2014 to now also include capacity procurement. YEC seeks capacity from DSM; both from traditional DSM programming, demand response types of programs, or both. To account for this change, the approach to modeling avoided cost has been upgraded to differentiate between the avoided cost of capacity (diesel emergency reserve, in $/kW-yr) and the avoided cost of energy.

Furthermore, under YEC's current supply and demand forecast, the supply in energy is expected be a mix of LNG, diesel and hydro power. During some portion of the year, now and in the foreseeable future, YEC will have to spill water from its reservoirs, which means that energy saved during period when it is simply adding to the water being spilled is worthless. Any kWh saved between the time YEC stops generating with its thermal gensets through to the time of the year when they spill, will simply result in additional water being spilled. To account for this change, the structure of the DSM cost effectiveness model has been modified to accommodate time varying avoided energy costs as part of the cost-effectiveness analysis.

1.4.1.2 Time- Varying Avoided Energy Costs

ICF modified the structure of the DSM cost effectiveness model to accommodate time varying avoided energy costs as part of the cost-effectiveness analysis. The avoided costs were split into 9 time bins (similar to time of use rate time bins) to account for differences in avoided costs from changes in the fuel resource mix over these times. The following exhibit presents the avoided costs in each time bin:

Exhibit 30: Avoided Energy Costs

Time Bin	Value ($/kWh)
Winter, Off-Peak	$0.0250
Winter, Peak	$0.1313
Winter, Mid-Peak	$0.1218
Winter Shoulder, Mid-Peak	$0.0144
Winter Shoulder, Off-Peak	$0.0010
Summer, Off-Peak	$0.00
Summer, Mid-Peak	$0.00
Summer Shoulder, Off-Peak	$0.0004
Summer Shoulder, Mid-Peak	$0.0167

The avoided costs in the table above were developed by YEC's load forecasting team taking the following factors into consideration:

- In the winter, hydro generation capacity is reduced due to the lower level of water in the reservoirs. Furthermore, grid operators run the risk of running out of water before the thaw so they prefer to minimize the use of the hydro plant if they can. Consequently, operators will run the LNG gensets most of the time not only to deliver enough capacity, but also to ensure the supply of enough energy until the end of winter. During frequent yet brief occasions, the operators must run diesel gensets in addition to the hydro plant and the LNG gensets to cope with winter peaks.

- During winter shoulder (period immediately after the thaw), waters from melting snow and ice fill the river beds. The operators are less worried regarding to the availability of water, and any water saved and stored in reservoirs would add to the water that will eventually be spilled during the summer. Consequently, operators use the hydro plants to their maximum capacity considering the water level and water harvest. However, since reservoirs are not filled yet, the water level is low and the demand remains relatively high. As such, the operators frequently need supplemental capacity from the LNG gensets.
- During the summer, the demand is at its lowest, the water flow is high, the reservoirs are full and the water level is at its highest point, which means that more capacity is available. Operators commonly must spill water, therefore any kWh saved (or generated with solar PV) will simply cause more water to be spilled.
- During summer shoulder, the water level is still high, the demand is rising yet is lower than in the winter, but the operators choose to run the LNG genset frequently nevertheless to minimize the risk of running out of water before the thaw.
- The avoided costs are based on fuel costs, and exclude labour and other non-fuel costs.

1.4.1.3 Avoided Capacity Costs

Avoided capacity costs were used to include the impact of the reduction in coincident peak demand capacity. In the previous program design for YEC, the avoided energy supply cost included a levelized cost of capacity, therefore the avoided cost of capacity was not considered separately. The following approach was implemented in this iteration of the program design modelling:

Exhibit 31: Avoided Capacity Costs

Year	Avoided Cost of Capacity ($/kW-yr)	Approach
2022	$211	This value based on the rental diesel cost stated in the Battery Energy Storage system Part 3 application to the Yukon Utilities Board (page 17, footnote 29), and is in 2022 dollars. The cost of capacity is escalated by 4% (real) per year.

1.5 Load Profile Development

In order to facilitate the analysis of measure cost-effectiveness using time-varying avoided costs and a more sophisticated analysis of peak demand impacts, it was necessary to develop end-use load profiles. These end-use load profiles allow us to estimate the distribution measure savings in each of the avoided cost periods. They also allow for the development of more accurate peak demand estimates at the measure level.

1.5.1 Sector & End-Use Level Load Profile Development

Using the provided aggregate hourly consumption data for 2017, ICF developed end-use load profiles at the sector level based on estimates of how energy is used at the end-use level. First, a general residential and commercial 8760 load profile was created by subtracting the load profile for the industrial sector and mines from the overall load data. Then, general residential and commercial load profiles for a representative weekday and weekend were created to split the total commercial and residential 8760 load into individual load profiles for each sector. These general load profiles were calibrated based upon the split in consumption between these sectors from the updated 2016 Yukon CPS. The following exhibits show an illustration of the estimated commercial vs. residential split for a winter weekday and weekend:

Exhibit 32: Typical Winter Peak Day Commercial vs Residential Load (Weekday)

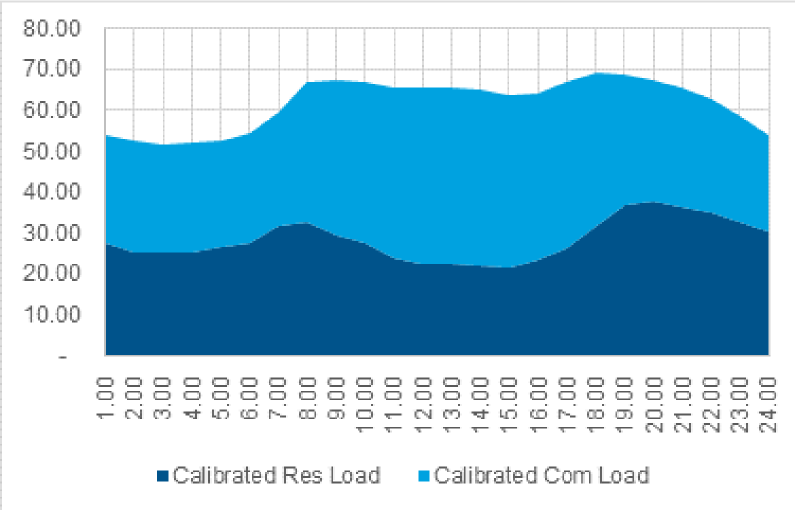
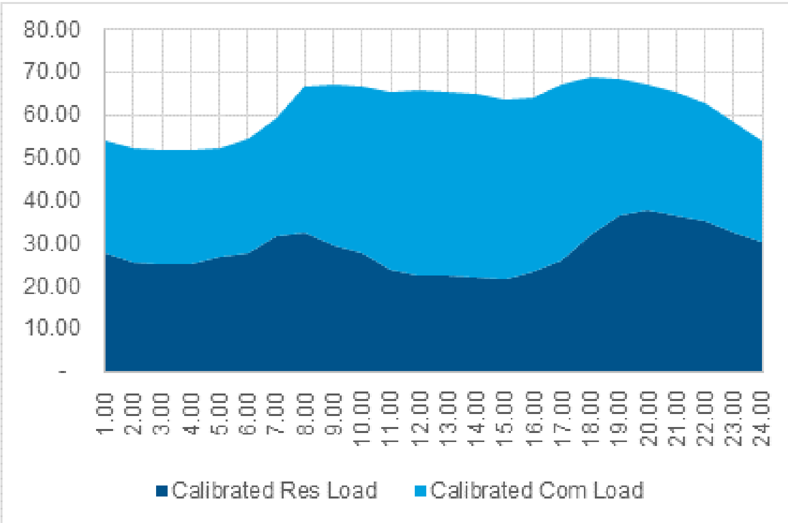
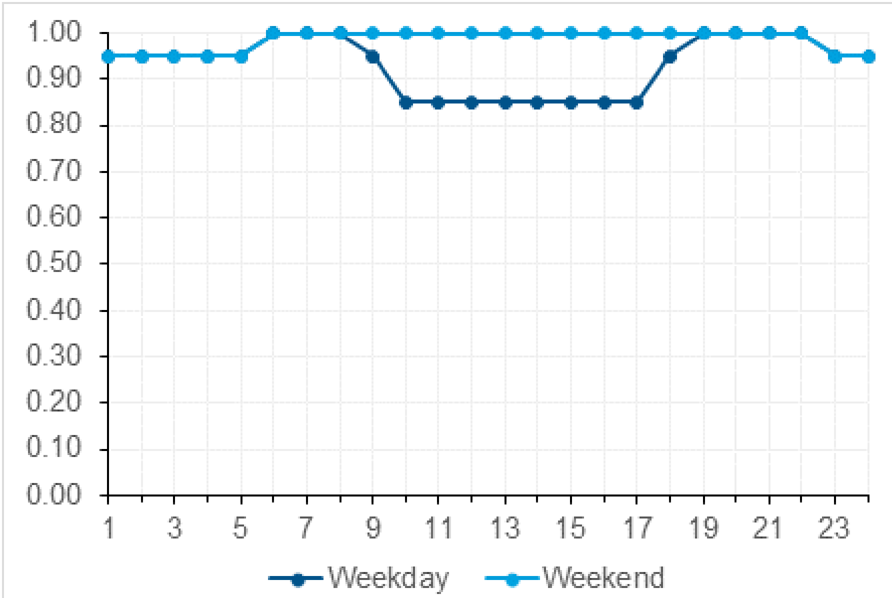


Exhibit 33 Typical Winter Peak Day Commercial vs Residential Load (Weekend)



The individual 8760 residential and commercial load profiles were further segmented into end-use profiles based upon the major energy end-uses present within each sector. Custom scaling curves were developed for each end-use, for a typical weekday and weekend, based upon estimates of how consumption in each end-use category is distributed. The scaling was driven by factors such as occupancy, weather, solar radiation, or expected customer behaviours. For example, the space heating profile was linked to the available heating degree day data for Yukon. The following exhibit provides the scaling curve for the residential space heating profile:

Exhibit 34: Scaling Curve for Space Heating Load Profile



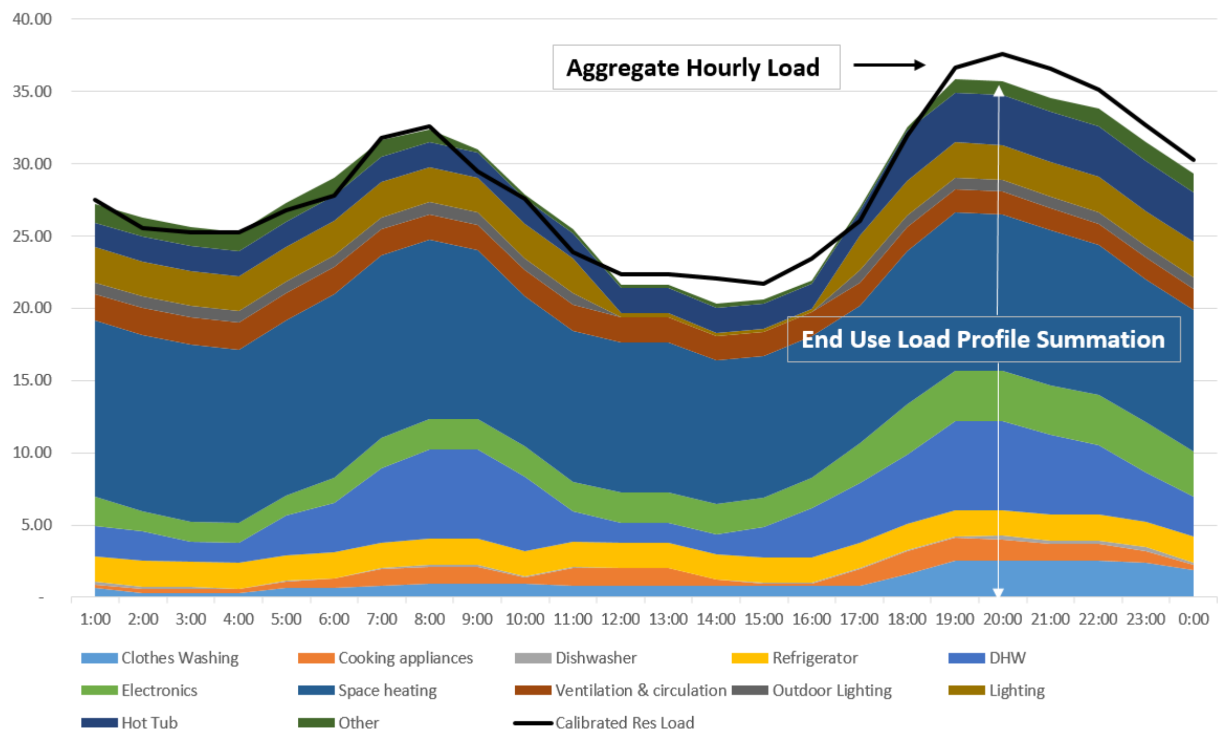
The summation of these end-use load profiles was then compared against the aggregate hourly consumption data to ensure there is reasonable agreement. Knowledge of how the usage patterns for each end-use differ from the sector average was used to estimate impacts at the end-use level. A list of the end-use categories for each sector is provided below:

Exhibit 35: Residential & Commercial End-Use Load Profile Categories

Residential	Commercial
▪ Clothes Washing ▪ Cooking Appliances ▪ Dishwasher ▪ Refrigerator ▪ DHW ▪ Electronics ▪ Space Heating ▪ Ventilation & Circulation ▪ Outdoor Lighting ▪ Lighting ▪ Hot Tub ▪ Other	▪ Block Heaters ▪ Miscellaneous ▪ Food Service Equipment ▪ Space Heating ▪ HVAC Fans & Pumps ▪ Lighting ▪ Outdoor Lighting ▪ Computer Equipment ▪ Refrigeration ▪ Water Heating

The following exhibit shows an illustration of the comparison between the summation of residential end-use load profiles and the residential aggregate hourly consumption data for a typical winter design day in Yukon.

Exhibit 36 Residential Design Winter Day – 24 hour Load Profile



1.5.2 Load Profile Factors

For the measure-level peak demand savings analysis, ICF disaggregated the annual electrical consumption savings for each measure into the nine time bins. The modelling approach for this began with the load profiles that were developed for each sub-sector and end-use, as discussed in the previous section.

The load profiles were used to develop nine load factors for each end-use category, which essentially allow for the distribution of annual consumption savings (kWh) across each of the time periods being considered. The appropriate load profile factor was mapped to each respective measure based upon the end-use most applicable to the measure. The following tables present the residential and commercial load profile factors:

Exhibit 37: Residential Load Profile Factors

	Winter, Off-Peak	Winter, Peak	Winter, Mid-Peak	Winter Shoulder, Mid-Peak	Winter Shoulder, Off-Peak
Clothes Washing	0.066	0.103	0.161	0.201	0.051
Cooking appliances	0.055	0.131	0.144	0.210	0.042
DHW	0.071	0.130	0.128	0.197	0.055
Dishwasher	0.124	0.084	0.122	0.157	0.095
Electronics	0.093	0.101	0.134	0.180	0.072
Hot Tub	0.101	0.097	0.130	0.174	0.078
Lighting	0.171	0.133	0.119	0.080	0.126
Other	0.180	0.068	0.080	0.114	0.138
Outdoor Lighting	0.182	0.140	0.119	0.064	0.134
Refrigerator	0.110	0.096	0.123	0.168	0.084
Space heating	0.203	0.173	0.214	0.155	0.101
Heat Pumps	0.222	0.187	0.229	0.145	0.097
Ventilation & circulation	0.191	0.162	0.207	0.152	0.099

	Summer, Off-Peak	Summer, Mid-Peak	Summer Shoulder, Off-Peak	Summer Shoulder, Mid-Peak
Clothes Washing	0.150	0.101	0.033	0.134
Cooking appliances	0.143	0.109	0.028	0.140
DHW	0.144	0.108	0.036	0.131
Dishwasher	0.183	0.069	0.063	0.104
Electronics	0.152	0.100	0.047	0.120
Hot Tub	0.163	0.089	0.052	0.116
Lighting	0.161	0.026	0.087	0.097
Other	0.209	0.043	0.092	0.075
Outdoor Lighting	0.163	0.011	0.093	0.094
Refrigerator	0.147	0.105	0.056	0.111
Space heating	0.027	0.010	0.044	0.072
Heat Pumps	0.020	0.007	0.036	0.057
Ventilation & circulation	0.050	0.020	0.045	0.073

Exhibit 38: Commercial Load Profiles

	Winter, Off-Peak	Winter, Peak	Winter, Mid-Peak	Winter Shoulder, Mid-Peak	Winter Shoulder, Off-Peak
Block Heater	0.026	0.122	0.180	0.233	0.020
Computer Equipment	0.053	0.119	0.156	0.212	0.041
Food Service Equipment	0.040	0.119	0.170	0.222	0.030
HVAC Fans and Pumps	0.176	0.174	0.214	0.159	0.091
Lighting	0.055	0.113	0.160	0.210	0.042
Miscellaneous	0.072	0.104	0.152	0.197	0.055
Outdoor Lighting	0.182	0.140	0.119	0.064	0.134
Refrigeration	0.092	0.100	0.137	0.182	0.070
Space Heating	0.196	0.175	0.221	0.158	0.098
Water Heating	0.045	0.118	0.166	0.218	0.034

	Summer, Off-Peak	Summer, Mid-Peak	Summer Shoulder, Off-Peak	Summer Shoulder, Mid-Peak
Block Heater	0.086	0.167	0.013	0.153
Computer Equipment	0.084	0.169	0.027	0.139
Food Service Equipment	0.109	0.142	0.020	0.147
HVAC Fans and Pumps	0.047	0.021	0.041	0.076
Lighting	0.101	0.151	0.028	0.139
Miscellaneous	0.111	0.141	0.037	0.130
Outdoor Lighting	0.163	0.011	0.093	0.094
Refrigeration	0.138	0.114	0.047	0.121
Space Heating	0.026	0.011	0.043	0.073
Water Heating	0.106	0.147	0.023	0.144

2 Scope 2 – Capacity DSM Approach

This section details the steps for the approach and analysis of the DR programs presented in the main body of the report.

This section begins with a high-level overview of Yukon's current resource needs and an analysis of YEC's 2017 load data. This is followed by a feasibility assessment of various capacity DSM options for Yukon.

2.1 Yukon Load Analysis

The 2016 resource plan highlighted that YEC is currently facing a capacity gap and needs new capacity to meet future customer needs. As per the resource plan, YEC currently is not meeting its reliability criterion, the N-1 criterion, which means that the peak load must be met even when the largest generation resource is lost. YEC's demand-side management (DSM) focus has shifted to emphasize Capacity DSM to help address capacity constraints.

The current challenge is to find Capacity DSM solutions that are technically sound, cost effective, and environmentally, socially, and economically responsible. YEC engaged ICF to provide recommendations on relevant and applicable Capacity DSM programs and pilot design to support the objectives outlined in YEC's 2016 Resource Plan. The load analysis discussed in this section is used to inform the investigation of potential capacity DSM programs suitable for YEC.

2.1.1 Yukon Capacity & Dispatch Sequence

Yukon is a winter peaking jurisdiction and power generation is largely based on legacy hydroelectricity. As discussed in section 1.4.1.2, there is increased generation from run of the river hydro in the summer (during the snowmelt period) and less water availability for hydro generation in the colder winter season when demand is highest. Therefore, LNG is the resource that is relied upon for most of the winter, with diesel used for the highest point in the winter peak demand. Depending on future scenarios for load growth, the diesel usage may run higher or lower.

The following table presents the hourly load schedule by each season, as provided by YEC planning staff:

Exhibit 39: Hourly Load Schedule

Season	Peak	Mid-Peak	Off-Peak
Winter: November, December, January, February	07:00 – 10:00 16:00 – 20:00	10:00 – 16:00 20:00 – 23:00	00:00 – 07:00 23:00 – 00:00
Winter Shoulder: March, April, May	N/A	07:00 – 23:00	00:00 – 07:00 23:00 – 00:00
Summer: June, July, August	N/A	08:00 – 18:00	00:00 – 08:00 18:00 – 00:00
Summer Shoulder: September, October	N/A	07:00 – 23:00	00:00 – 07:00 23:00 – 00:00

2.1.2 Peak Load Occurrence

One of the primary considerations in addressing the capacity gap faced by YEC was to identify when the peak occurrences are, and the lengths of these winter peaks. According to the resource plan, YEC's highest historical electricity demand peaked at 88 MW on December 15th 2016,[17] and the peak occurrence for Yukon is in the morning and evening. Planning staff at YEC noted that the morning peak occurs within the hours of 6-10 am, with the highest part of the peak from 7- 9 am. The evening peak was noted to occur from 4-8 pm, with the highest part of the peak from 4:30-6:30 pm.[18] To support this, we developed heat maps for the 2017 calendar year load data. The following heat maps are presented below for 2017:

1. 24h Series for Weekday Load Maximum by Month in 2017
2. 24h Series for Weekend Load Maximum by Month in 2017
3. 24h Series for Day of Highest Peak Occurrence by Month (2017)

[17] Yukon Energy Corporation, "Yukon Energy 2016 Resource Plan," 2017.

[18] Morgan,G., YEC Manager of Operations

Exhibit 40: Weekday Load Maximum by Month in 2017 (MW)

2017 Weekday Load Max (MW)

Max of YEC_Load	Month											
Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	64.2	61.1	60.6	42.6	38.1	35.9	36.3	35.2	36.2	42.1	60.8	70.1
2	62.6	59.7	59.8	41.4	36.6	34.3	34.7	33.2	34.1	41.7	59.3	68.8
3	62.4	59.4	60.1	41.2	36.2	33.0	33.6	32.4	33.5	41.5	58.7	68.0
4	62.7	59.3	59.3	41.5	36.1	32.3	33.0	32.0	33.4	41.7	58.7	67.6
5	63.7	59.9	60.9	42.3	36.9	32.1	33.1	32.1	34.1	42.3	59.3	68.5
6	66.1	62.3	63.7	44.2	38.7	32.3	33.6	33.8	36.0	44.4	61.2	70.2
7	72.3	69.0	70.7	50.8	44.1	37.2	38.3	39.2	41.9	49.9	66.7	73.3
8	80.3	77.5	79.1	57.8	51.7	45.5	45.0	45.9	49.9	57.7	75.3	77.9
9	80.9	78.4	77.1	58.1	52.8	48.0	47.6	47.0	51.0	58.6	76.5	80.8
10	80.0	75.7	74.8	56.8	51.0	46.9	47.5	51.1	49.6	56.7	75.4	82.4
11	79.4	74.6	73.5	54.9	49.4	47.1	48.4	50.6	48.8	55.4	74.4	83.5
12	79.5	73.2	72.1	54.4	49.2	47.3	49.1	50.5	47.9	56.5	73.8	83.8
13	79.0	71.9	70.4	53.4	48.3	47.3	48.9	48.2	49.1	56.3	72.9	82.5
14	77.2	69.3	68.5	52.0	47.7	46.2	48.7	46.5	48.0	54.3	72.2	80.9
15	75.5	68.7	66.6	50.7	46.6	46.2	48.6	46.4	47.2	54.0	71.8	80.3
16	75.5	68.6	66.1	50.7	46.0	46.5	48.4	46.3	47.1	54.0	71.9	80.9
17	78.1	69.7	67.6	51.5	46.5	46.5	48.9	46.3	48.6	54.8	74.6	83.8
18	81.5	72.8	69.6	51.7	47.6	46.0	49.9	48.3	49.0	56.4	77.0	85.3
19	80.8	75.0	70.7	51.6	47.6	45.6	49.3	50.1	49.1	57.4	76.9	84.5
20	79.3	74.5	73.3	51.4	47.2	45.2	48.6	48.0	49.0	57.6	74.5	82.5
21	77.3	73.7	72.8	51.7	46.7	44.9	47.3	44.0	50.4	55.8	72.8	80.6
22	74.4	71.4	70.7	52.6	46.1	43.4	45.4	43.7	48.2	53.0	70.7	79.2
23	70.3	67.3	67.0	49.5	45.0	40.9	42.0	42.0	43.8	49.2	67.2	76.3
24	67.4	63.7	63.3	45.0	41.8	38.4	39.4	39.1	39.7	46.6	63.7	73.7

Exhibit 41: Weekend Load Maximum by Month in 2017 (MW)

2017 Weekend Load Max (MW)

Max of YEC_Load	Month											
Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	65.7	58.4	58.1	42.8	38.2	36.3	35.7	35.6	36.8	43.8	60.7	73.1
2	64.7	56.7	57.6	41.2	36.6	34.4	33.8	33.4	35.9	42.7	58.8	71.0
3	64.2	56.0	57.9	40.6	36.1	33.3	32.6	32.1	35.2	42.3	58.0	70.0
4	63.9	55.9	58.1	40.2	35.8	32.7	32.2	31.7	35.1	41.7	58.3	69.7
5	64.0	56.0	58.5	40.6	35.4	32.6	31.3	31.8	34.8	41.2	58.3	69.4
6	64.8	57.0	59.8	41.2	35.6	32.2	31.4	32.4	35.7	42.2	59.7	70.2
7	67.7	58.9	62.8	43.2	37.6	33.6	31.9	33.7	38.5	45.1	61.6	72.1
8	71.0	61.5	66.4	46.0	41.3	37.4	35.4	36.0	42.1	49.0	65.5	75.4
9	74.9	66.0	70.1	49.2	44.6	41.9	39.4	40.2	45.7	53.2	70.2	78.7
10	78.2	68.6	71.7	51.5	46.3	45.4	42.7	43.3	48.4	55.1	72.6	82.3
11	80.2	70.5	71.2	52.5	47.8	47.4	43.8	44.2	49.7	55.3	73.8	84.5
12	81.1	70.3	70.0	53.2	48.0	48.5	45.1	44.2	49.6	54.5	74.3	83.4
13	80.9	69.8	67.8	53.0	47.7	48.3	45.4	44.5	48.9	54.2	75.0	83.0
14	79.2	67.4	66.5	52.0	46.7	46.5	44.9	43.4	47.4	52.7	74.2	82.4
15	78.6	66.4	65.0	50.3	46.0	44.5	44.3	42.5	46.0	51.2	73.7	81.8
16	78.4	65.5	65.1	49.1	45.8	43.7	44.5	42.3	45.5	51.4	74.5	82.1
17	79.5	66.7	66.7	49.9	46.0	43.5	45.1	43.4	45.1	54.0	77.9	84.3
18	82.3	69.6	68.7	51.5	46.3	44.8	46.6	44.5	46.0	55.8	79.4	86.0
19	80.9	71.3	69.6	51.8	45.3	45.3	46.1	44.5	46.2	55.9	77.8	85.3
20	79.4	70.9	71.1	51.6	45.4	45.1	45.2	44.3	46.6	56.9	76.8	85.5
21	77.8	70.2	69.9	52.6	45.2	43.9	44.4	44.1	46.8	55.6	75.0	83.4
22	75.2	68.0	66.9	53.9	44.6	42.5	42.8	43.7	46.2	53.2	71.9	81.4
23	71.6	63.6	63.0	50.7	43.1	40.1	40.4	41.0	43.4	49.2	67.6	78.8
24	68.0	60.1	59.4	46.3	40.5	37.4	37.7	38.4	41.1	45.2	62.5	75.7

Exhibit 42: 24h Series for Day of Highest Peak Occurrence by Month (2017)

24h Series for Day of Highest Peak Occurence by Month (2017)

Month	1	2	3	4	5	6	7	8	9	10	11	12
Peak Occurrence	1/21/2017	2/8/2017	3/7/2017	4/3/2017	5/5/2017	6/17/2017	7/10/2017	8/8/2017	9/29/2017	10/23/2017	11/26/2017	12/30/2017
1	65.1	61.1	60.6	42.6	37.8	35.8	34.7	35.1	34.8	42.1	59.2	71.5
2	64.7	59.7	59.8	41.4	36.5	34.3	32.9	33.1	33.8	40.4	57.8	70.0
3	64.2	59.4	60.1	41.2	36.1	33.3	31.9	32.0	33.5	40.0	57.1	69.2
4	63.9	59.3	58.0	41.5	35.9	32.7	31.2	31.5	33.4	39.9	57.4	69.0
5	64.0	59.9	60.9	42.3	36.7	32.6	31.2	31.6	34.1	40.3	57.8	69.3
6	64.8	62.3	63.7	44.2	38.7	32.2	31.9	31.3	36.0	42.2	58.6	70.1
7	67.7	69.0	70.7	50.8	44.1	33.6	36.9	33.1	41.9	48.4	60.6	71.9
8	71.0	77.5	79.1	57.8	51.7	37.4	43.6	34.7	49.9	57.2	63.4	75.4
9	74.9	78.4	77.1	58.1	52.8	41.9	46.6	37.8	51.0	58.6	66.6	78.7
10	78.2	75.7	74.8	56.8	51.0	45.4	47.0	51.1	49.6	56.6	71.0	82.3
11	80.2	73.0	73.5	54.9	49.1	47.4	48.1	50.6	48.8	55.3	73.8	84.5
12	81.1	71.3	72.1	54.4	47.9	48.5	49.1	50.5	47.9	55.0	74.3	83.4
13	80.9	71.5	70.4	53.4	46.7	48.3	48.9	48.2	46.4	54.2	75.0	83.0
14	79.2	69.0	68.5	51.4	45.8	46.5	48.7	44.3	45.5	53.5	74.2	82.1
15	78.6	67.4	66.6	50.0	45.6	44.5	48.6	43.9	44.4	52.6	73.7	81.8
16	78.4	67.1	66.1	49.5	45.1	43.5	48.4	43.2	43.6	52.0	74.5	82.1
17	79.5	68.5	67.6	50.2	45.5	42.6	48.9	43.7	43.2	53.9	77.9	84.3
18	82.3	71.5	69.6	51.5	45.7	42.8	49.9	48.3	43.3	55.4	79.4	86.0
19	80.9	73.6	70.7	51.6	44.6	42.7	49.3	50.1	43.9	57.4	77.8	85.3
20	78.3	73.4	73.3	51.4	43.8	42.0	48.6	48.0	44.5	57.6	76.8	85.5
21	76.1	72.3	72.6	51.7	42.7	41.0	47.3	42.4	45.5	55.8	75.0	83.4
22	74.2	69.7	70.4	52.6	42.2	40.0	45.4	42.2	44.4	53.0	71.9	81.4
23	71.6	66.2	66.0	49.5	42.3	38.5	42.0	40.6	42.1	48.9	67.6	78.8
24	68.0	61.5	61.9	45.0	40.7	36.7	39.4	38.7	39.7	44.7	62.4	75.7

Based on the exhibits above, it can be confirmed that electric demand in YEC is highest during the winter months of November to February with the highest electrical demand occurring in the month of December.

However, the highest part of the peak, for the load maximum on the 30th of December in particular, did not occur from 7 am to 9 am in 2017. Instead, there was a prolonged 13-hour period of peak electrical demand from the hours of 10 am to 11 pm, with the highest part of the peak occurring between 5 pm to 9 pm. Additional periods of prolonged peak electrical demand are further demonstrated in the sections below (see section 2.1.4).

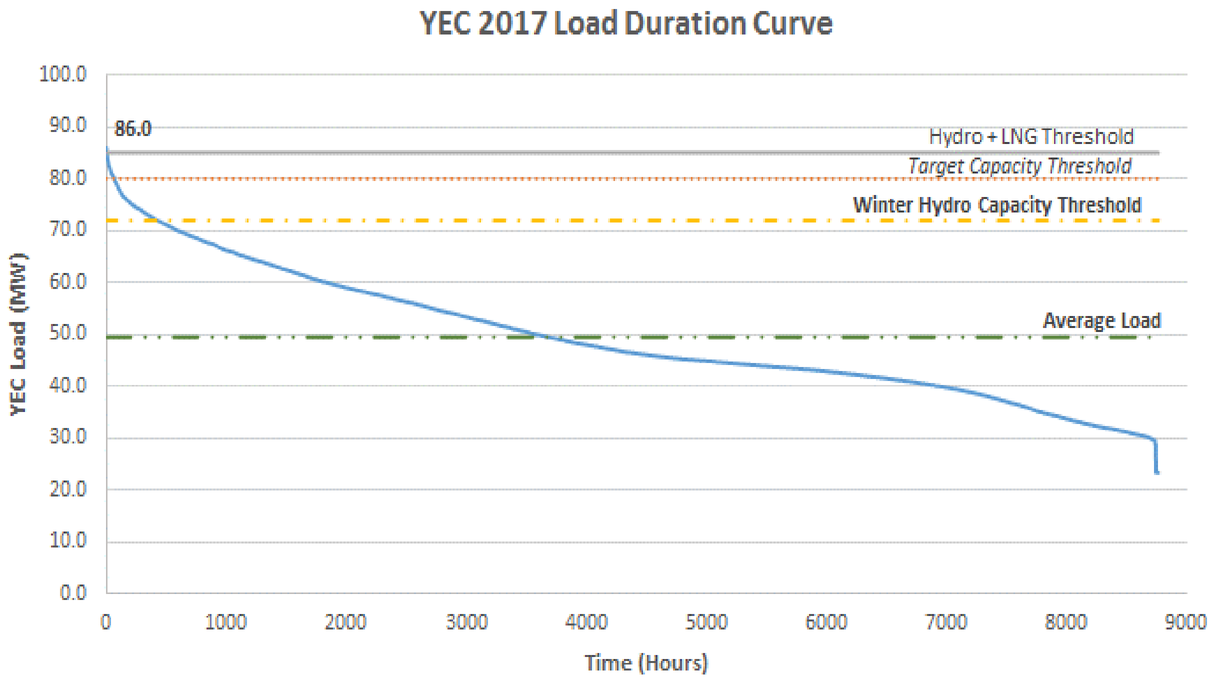
2.1.3 Peak Load Duration Curve

A load duration curve (LDC) analysis was completed for the 2017 load data from YEC to identify and characterize the maximum utility load, the distribution of energy demand, the average load, and the base load.

To generate the load duration curve, the chronological 2017 YEC load data was re-arranged in the order of descending load magnitude.

The following chart presents the 2017 load duration curve for YEC:

Exhibit 43: 2017 Load Duration Curve



Note: this chart has been adjusted to correct for data errors such as negative values

The LDC above illustrates that the maximum load for 2017 was found to be a total of 86 MW. This maximum load was found to have occurred at 6:00 pm on December 30th 2017. There is a maximum winter hydro capacity threshold of 72 MW, and another 13 MW of available LNG capacity for a total hydro and LNG generation capacity of 85 MW.

2.1.4 Peak Period Occurrences in 2017

To identify the addressable peak load from YEC's 2017 load data, all data points greater than or equal to a given load of 80 MW (6 MW below the maximum 2017 peak of 86 MW) were assessed to determine the variation in the duration of periods of high peak load. The following table presents the 15 periods in 2017 with a load above a targeted 80 MW threshold:

Exhibit 44: Periods of High Peak Occurrence in 2017

Date & Time	Load (MW)	Peak Duration (hours)
1/7/2017 18:00	80.4	1
1/8/2017 18:00	81.6	2
1/8/2017 19:00	80.8	
1/9/2017 8:00	80.3	3
1/9/2017 9:00	80.9	
1/9/2017 10:00	80.0	
1/9/2017 18:00	81.5	2
1/9/2017 19:00	80.8	
1/21/2017 11:00	80.2	3
1/21/2017 12:00	81.1	
1/21/2017 13:00	80.9	

Date & Time	Load (MW)	Peak Duration (hours)
1/21/2017 18:00	82.3	2
1/21/2017 19:00	80.9	
12/24/2017 17:00	80.3	1
12/27/2017 11:00	80.6	3
12/27/2017 12:00	81.2	
12/27/2017 13:00	80.7	
12/27/2017 17:00	81.4	4
12/27/2017 18:00	83.0	
12/27/2017 19:00	81.9	
12/27/2017 20:00	80.5	
12/28/2017 11:00	80.7	3
12/28/2017 12:00	80.9	
12/28/2017 13:00	80.6	
12/28/2017 16:00	80.0	6
12/28/2017 17:00	82.6	
12/28/2017 18:00	84.6	
12/28/2017 19:00	83.8	
12/28/2017 20:00	82.4	
12/28/2017 21:00	80.6	
12/29/2017 9:00	80.8	13
12/29/2017 10:00	82.4	
12/29/2017 11:00	83.5	
12/29/2017 12:00	83.8	
12/29/2017 13:00	82.5	
12/29/2017 14:00	80.9	
12/29/2017 15:00	80.3	
12/29/2017 16:00	80.9	
12/29/2017 17:00	83.8	
12/29/2017 18:00	85.3	
12/29/2017 19:00	84.5	
12/29/2017 20:00	82.5	
12/29/2017 21:00	80.6	
12/30/2017 10:00	82.3	13
12/30/2017 11:00	84.5	
12/30/2017 12:00	83.4	
12/30/2017 13:00	83.0	
12/30/2017 14:00	82.1	
12/30/2017 15:00	81.8	
12/30/2017 16:00	82.1	
12/30/2017 17:00	84.3	
12/30/2017 18:00	86.0	

Date & Time	Load (MW)	Peak Duration (hours)
12/30/2017 19:00	85.3	
12/30/2017 20:00	85.5	
12/30/2017 21:00	83.4	
12/30/2017 22:00	81.4	
12/31/2017 10:00	81.8	6
12/31/2017 11:00	81.7	
12/31/2017 12:00	81.5	
12/31/2017 13:00	82.8	
12/31/2017 14:00	82.4	
12/31/2017 15:00	80.8	
12/31/2017 17:00	82.3	4
12/31/2017 18:00	83.5	
12/31/2017 19:00	83.4	
12/31/2017 20:00	81.3	

Exhibit 45 shows the maximum peak threshold that can be achieved for various curtailment durations (based on the 2017 load data):

Exhibit 45: Maximum Peak Load Thresholds (2017)

Threshold (MW)	Required Peak Duration (hours)
>80.0	13
>83.5	4
>84.3	3
>85.4	2
>85.5	1

In order to sustain a 6 MW curtailment (to reach an 80 MW peak), the length alone of one DR event must be able to last for 13 hours. This is an extended period of peak load occurrence which is beyond the typical duration of curtailment that can be achieved through direct load control. Typically, direct load control systems that do not include thermal storage and employ simple load shedding strategy can provide peak demand curtailment for only 4 hours at most. Load shedding of electric water heaters for example can be effective for the duration of time that a customer can rely upon stored hot water. The duration for water heater control is limited by the amount of time it takes for participants to run out of hot water. Sustaining an event beyond 4 hours increases the risk that customers will experience periods of discomfort. The snapback is another constraining factor, since a fleet of device being curtained simultaneously will draw load in a synchronized fashion at the end of the curtailment.

There are smart algorithms that can use temperature readings (space or hot water temperature) and develop sophisticated staggering or cycling approaches to both extend the duration of the curtailment and dampen the snap back, but they are relatively untested in Canada, and they reduce the curtailment that can be expected on a per-device basis (the normalized curtailment).

2.2 Preliminary Assessment of Potential Capacity DSM Options for Yukon

This section presents the broad range of preliminary options considered for capacity DSM, as introduced in the earlier 2018/2019 Capacity DSM Options report. In the selection of preliminary capacity DSM measures, absence of air conditioning load, and the high penetration of electric space heating and domestic hot water have been taken into consideration.

Several of the options below were removed from further consideration after research and analysis or discussion with market actors identified the limited potential in Yukon for these options. The preliminary assessment decision is noted in the final column of this table.

Exhibit 46: Preliminary Assessment of Capacity DSM Measure Options

#	Capacity DSM Option	Description	Preliminary Assessment Decision
Space Heating Control			
1	Electric Thermal Storage	Specialized electric heater that stores heat during off-peak hours, and then releases the stored heat when it is required.	**Recommended for further analysis** – This option was selected for further analysis as there is strong public interest in ETS by interested parties such as the Yukon Conservation Society. ETS units are able to store heat overnight and as such they are expected to meet YEC's needs to curtail demand over an extended 13 hour DR event. A jurisdictional scan of this measure showed there to be successful experiences with ETS in Summerside, PEI, Nova Scotia, and Alaska.
2	Utility-Controlled Line Voltage Thermostat	Web programmable electric heating thermostats for homes with baseboard heating allow for remote control and programming.	**Recommended for further analysis** – This option was selected for further analysis as there is an increasingly larger shift towards electric baseboard heating in new construction homes in Yukon and these homes are unable to rely upon standard web-programmable thermostat options due to their incompatibility with baseboard heating systems. A jurisdiction scan of this measure showed there to be examples of DR pilots in Quebec and BC using line voltage communicating thermostats.
3	Utility-Controlled Central Air Thermostats	Web programmable electric heating thermostats for homes with central air systems for remote control and programming.	**Recommended for further analysis** – This option was selected for further analysis as there is a large portion of existing homes that are electrically heated in Yukon and have central air heating systems.
Water Heater Control			
4	Three-Element Water Heaters	This is a passive technology (non-dispatchable) that was designed by a large Canadian water heater manufacturer to dampen the peak from the operation of a fleet of water heaters. The peak dampening simply occurs by effect of different control equipment and sequence built in the water heater. While the technology curtails demand, not energy, because it is not dispatchable,	**Removed from consideration under Capacity DSM –** This option was assessed as part of the regular DSM portfolio for Yukon due to this technology being non-dispatchable. Three-element water heaters manufactured by Giant were identified to

		this technology could also be part of a regular energy efficiency program rather than a DR program.	be adopted by Hydro Quebec as an instant rebate offer of $100[19].
5	Grid-Interactive Water Heater	Grid interactive water heating (GIWH) adds bi-directional control to electric resistance water heaters allowing the utility or third-party aggregator to rapidly and repeatedly turn them on and off, or incrementally ramp their power up and down to allow a fleet of water heaters to be utilized for energy storage	**Recommended for further analysis** – This option was selected for further analysis as the load profile analysis demonstrated the domestic hot water heating to make up a large portion of the load coincident with the peak. This option is one of three potential domestic hot water control options, with the other two being less sophisticated control options, instrumented control and non-instrumented DHW control. DHW control is a demand response technology with successful applications in many other jurisdictions across North America including demand response programs for DHW by BGE, PSE, and PowerShift Atlantic.
6	Utility-Controlled, Instrumented Water Heater	Temperature sensitive control switch installed on water heating system circuits or unit for utility or temperature controlled remote shut off or cycling control. The utility has the ability to control the water heaters remotely as a fleet.	**Recommended for further analysis** – This option was selected for further analysis as the load profile analysis showed domestic hot water heating to make up a large portion of the load coincident with the peak. Temperature sensitive DHW control has been successfully implemented in other jurisdictions, including a pilot study example in Minnesota in which controllers by the manufacturer Aquanta were shown to produce savings in the range of 2.3-9.3%[20].
7	Utility-Controlled, Non-Instrumented Water Heater	Control switch installed on water heating system circuits or unit for utility-controlled remote shut off or cycling control.	**Recommended for further analysis** – This option was selected for further analysis as the load profile analysis showed domestic hot water heating to

[19] http://www.hydroquebec.com/data/mieux-consommer/ecopeak/pdf/chauffe-eau-modalites-english.pdf

[20] Minnesota Department of Commerce. *Field Study of an Intelligent, Networked, Retrofittable Water Heater Controller.* 2018. http://mn.gov/commerce-stat/pdfs/card-water-heater-contoller.pdf

			make up a large portion of the load coincident with the peak.
Lighting Control			
8	Non-essential lighting control	Control system or switch installed on non-essential lighting plug loads and circuits (e.g. holiday lights, secondary lighting systems) for utility control during system critical events	**Recommended for further analysis** – This option was selected for further analysis as there is a very high lighting load in Yukon due to the limited hours of sunlight in the winter peaking season. Based on the load profile analysis, commercial lighting is highly peak coincident (estimated of making up ~30% of peak commercial load). Preliminary research shows there are a number of intelligent demand control and demand response options available for advanced LED lighting in commercial facilities, including network lighting control options that have been certified to meet specific requirements by the DLC (DesignLights Consortium).
9	Smart Street Lighting (SSL) Control	Outdoor lighting control system using an intelligent control system with digital networks and embedded sensors to provide remote utility monitoring and control of the level of light output from the light source.	**Removed from further consideration under Capacity DSM –** This option was removed from further consideration as a capacity DSM option. A public lighting program for LED Street Lighting has been recommended as part of the regular DSM portfolio. The public lighting DSM program will be a joint collaboration between YEC and ATCO.
Other, Multi-End Uses			
10	Behind the Meter Emergency Generator Control	Using a fleet of embedded emergency generators to relieve system constraints as an emergency DR solution.	**Recommended for further analysis** – This option was recommended for further analysis based on the capability to off-load energy for long periods of time, which is useful to the territory of Yukon with long extended peak occurrences.
11	Demand Response Alerts	This is a behavioural program using a smart grid system that uses residential customer response to email and SMS message alerts encouraging them to take action in reducing and/or deferring their electrical consumption during a critical peak period.	**Recommended for further analysis** – This is a demand response program with successful examples across many other jurisdictions in North America. The challenge identified in implementation of this program for YEC is the lack of advanced metering infrastructure. However, this option was selected for further analysis and consideration as the TAC meeting attendees showed great interest in behavioural programming and

			there is potential to integrate the delivery of the demand response alerts into the proposed home energy reporting DSM program for residential customers.
12	Energy Management System	An energy management hardware/software platform that can dynamically manage energy usage across multiple end use equipment for large commercial facilities through a DR event.	**Recommended for further analysis** – This option was selected for further analysis as the control of BAS allows for the cycling of HVAC equipment, lighting, and other business processes which collectively provide a significant level of contribution to the savings coincident with the peak in the commercial sector.
13	Pool and Hot Tub Pump Control	This is a control technology to lower the speed of variable speed pool and hot tub pumps. Unlike single speed pumps, variable speed pumps have the ability to lower pumping speed during critical peak period DR events.	**Removed from consideration –** This option was removed for further consideration based on the load profile analysis showing that the hot tub market represents a very small portion of the overall load (less than 10%). While there are examples of pool pump demand response in summer peaking jurisdictions, there were no identified examples of hot tub pump control for winter peaking jurisdictions.
14	Residential Battery Storage	This is home energy storage technology using a rechargeable lithium-ion battery for load shifting, back-up power and demand response during a utility DR event.	**Recommended for further analysis – Recommended for further analysis** This option was recommended for further analysis based on the capability to store energy for long periods of time, which is useful to the territory of Yukon with long extended peak occurrences.

Based on the above, from the initial list of fourteen DR technology options, there were eleven options that are recommended for further analysis under the capacity DSM feasibility assessment to quantify the curtailment potential and cost-effectiveness of each measure.

2.3 Capacity DSM Feasibility Assessment

This section presents the demand response energy modelling work that was conducted for the preliminary capacity DSM options selected for further analysis. This feasibility assessment was conducted to quantify the potential benefits of each option in terms of MW curtailment potential and to recommend measures to be included in the final recommended capacity DSM programs (as presented in the main body of this report).

2.3.1 Initial Measure Level Savings

Measure input assumptions and parameters include incremental costs, peak curtailment (kW), effective useful life.

Information on the cost of implementing each measure was compiled from primary and secondary sources. ICF reached out to direct manufacturers of the DR technologies to obtain equipment pricing estimates and to discuss technology limitations.

Similar to the scope 1 DSM measures, the full assumptions for each capacity DSM measure can be found in the technical resource manual documentation.

2.3.2 Initial Estimates of Peak Curtailment & Cost Effectiveness by Measure

The eleven demand response technologies were assessed for cost-effectiveness at a measure level. This assessment was completed to provide a simple TRC benefit-cost analysis basis upon which we were able to exclude capacity DSM measures that would not be able to withstand the utility cost-effectiveness test (UCT), including the impacts of program level incentives and participation.

It is important to emphasize that the actual curtailment impacts would vary for each participant in a program dependent on various factors including the size of the participating customers, and varying behavioural and occupancy patterns of participants. For the residential sector measures, peak curtailment estimates have been developed for an average Yukon dwelling. Since there is a greater level of variability in loads between commercial customers, these measures have been split into three categorizations to show the average peak load curtailment for a small, medium, and large commercial customer (based on estimates of floor space areas for each category).

The curtailment impacts presented below do not include the impacts of snapback or cold-load pickup, which can have the potential to increase demand after a DR event, potentially at a level significant enough to cause a larger peak. Snapback effects are discussed further in this appendix (section 2.3.5).

Exhibit 47: Initial Peak Curtailment & Cost-Effectiveness Assessment

Measure	Unit	Persistence in Program (Yr)	Measure Cost Estimate	kW Curtailment/ unit	Initial Cost Effectiveness B/C Ratio
Grid Integrated DHW - Residential	per control system	15	$3,600	1.3	2.5
Line Voltage Connected Thermostats - Residential	per dwelling	10	$1,490	2.0	7.7
Central Air Web Enabled Thermostats - Residential	per dwelling	10	$1,310	2.6	10.7
Text/Email Message Alert - Residential	per dwelling	5	$70	0.1	6.4
Baseboard Electric Thermal Storage - Residential	per ETS unit	15	$6,410	2.1	2.3
Emergency Generation - Small	per control system	10	$43,265	16.0	2.2
Emergency Generation - Med	per control system	10	$46,475	79.8	8.6
Emergency Generation - Large	per control system	10	$49,085	133.1	12.2
DHW Control - Instrumented	per control system	15	$1,555	0.8	3.7
DHW Control - Non-Instrumented	per control system	15	$1,405	0.6	3.1
Battery Storage - Residential	per dwelling	15	$25,070	1.6	0.5
EMS/BAS – Small C/I	per customer	10	$66,585	1.2	0.1
EMS/BAS – Med C/I	per customer	10	$73,005	6.2	0.5
EMS/BAS – Large C/I	per customer	10	$78,220	20.7	1.6
Network Controlled Lighting – Small C/I	per customer	10	$26,605	0.3	0.1
Network Controlled Lighting – Med C/I	per customer	10	$53,225	1.6	0.2
Network Controlled Lighting – Large C/I	per customer	10	$130,875	5.3	0.3

	Cost-Effective, recommended for detailed load impact analysis		Not recommended due to initial cost-ineffectiveness level assessment

2.3.2.1 DHW Control Selection

For the DHW control, there were 3 types of control options assessed including grid integrated DHW control, instrumented DHW control, and non-instrumented DHW control. All three of these measures were found to be cost-effective, however the peak curtailment potential for the grid-integrated option was found to be higher than the non-grid integrated control options.

The instrumented and non-instrumented water heater control options are controller-only options that can be installed on a retrofit basis (i.e. they don't require replacing the tank). The non-instrumented option consists of the use of an electrical load controller for an individual water heater, and as such this option is more limited in functionality (ie. on/off control with a solid state relay). In the case of an instrumented water heater, the DHW control approach is more sophisticated and involves temperature reading that allows the control system to prevent the water temperature level for a DHW tank to decrease below a certain threshold value. As such, the curtailment strategy can be more aggressive because the system prevents shortage of hot water. In this scenario, while most water heaters would switch off at the start of a DR event, a number of water heaters would start to switch back on during the event as that temperature threshold is crossed.

Grid Integrated Water Heater Control entails a full DHW tank replacement with a new DHW tank with 2.5" or more of foam insulation and a non-metallic inner tank that is fully instrumented with several temperature sensors and a more sophisticated controller. The insulating properties of this tank, the non-metallic nature of the inner-tank, and an addition of an anti-scalding mixing valve device allow for the water to be heated above the regular set-point temperature of a hot water tank to a temperature of 140 deg. F while ensuring that occupants are not at risk of being scalded.

Given that the Yukon integrated system would require a longer duration curtailment of domestic water heaters (as per the load analysis completed above), and to minimize the unsuccessful curtailment of a portion of participating units, the grid integrated option was selected for the detailed load curtailment analysis.

2.3.2.2 Measures that Showed Poor Cost-Effectiveness

Three of the assessed measures were found to be cost-ineffective including the following:

Commercial DR:

- **Network Controlled Lighting:** This measure was found to be the most cost-ineffective solution, with minimal curtailment potential. The cost of a lighting system is very labour-intensive and made up of a number of pieces of equipment which may be unique to each specific site. This includes high costs of electrical wiring, controllers, lamps, sensors, switches, network gear, and licensing. Business operations are expected to only allow for the dimming of the control of secondary lighting loads, which limits the curtailment potential for a network-controlled lighting solution. When the limited curtailment potential is weighed against the high system costs, this produces a very low cost-effectiveness result.
- **EMS/BAS Control:** Energy management system (EMS) or building automation system (BAS) control the building HVAC system. In the winter, most commercial building with a EMS/BAS system heat with heating oil or propane. The majority loads controlled that could be curtailed in most buildings during the winter peaks are pumps and fans, which do not represent a large load. There are a few exceptions, however. Refrigeration compressors installed in ice rinks and grocery stores could be of interest at a later date. They are typically not controllers by the EMS/BAS, as refrigeration most often has a separate control system. The Commercial DR system that would be deployed to control refrigeration contractor, however, is the same than that for the remote control of emergency generators.

Residential DR:

- **Residential Battery Storage:** The length of curtailment for residential battery storage is limited by the size of the battery. It was determined that an extended 13 hours of peak curtailment is possible to meet the minimum energy requirements of an average Yukon home, with approx. 27 kWh of battery storage units. However, a battery storage solution of this size was found to be cost-prohibitive with minimal curtailment potential producing a cost-effectiveness result below 1.

2.3.3 DR Event Design

The 2017 aggregate load data provided by YEC was used to develop estimates of peak curtailment for a simulated annual demand response event for the utility. The demand response event day was selected based on the date of highest peak demand occurrence in 2017, identified as December 30th 2017.

2.3.4 Load Shaving Duration

The next step in the DR energy modelling consisted of the selection of DR event load shaving periods for each measure. The event schedules were selected based on the maximum achievable length of curtailment for each measure.

- **Short Duration Peak Curtailment Measures (maximum 4-hour curtailment):** The duration of peak curtailment for these measures is limited by impacts upon customer comfort and business operational needs that do not allow for the switching off of equipment for long durations. From the remaining DR measures under analysis, this applies to the line voltage communicating thermostats and the central air thermostats. These measures may be used to support Yukon through shorter periods of peak occurrence or in conjunction with longer duration measures.
- **Longer Duration Peak Curtailment Measures (13-hour curtailment):** Measures with storage capabilities or off-loading to emergency generators are expected to allow for a longer duration of curtailment with limited impacts upon customer comfort, provided that the storage capacity or embedded generator capacity is sufficient.

Grid integrated water heater (GIWH) and grid interactive ETS systems rely upon a sophisticated DRMS system which is able to manage the needs of the Yukon Integrated System to intelligently cycle or ramp-up/ramp-down the output as needed

The limitations upon the length of curtailment from emergency generators can be impacted by the size of the generator, the fuel tank size, and licensing requirements. However, provided that the generator has the capacity to serve the needs of the building and that the above considerations are accounted for in the implementation of such a program, emergency generator control has the potential to sustain peak curtailment for extended periods of time.

2.3.5 Snapback

Post DR event load building is referred to as the snapback effect. In periods of snapback, the load ramps up after a DR event, in some cases being higher than it may have been in the absence of a DR event. This effect is of importance to Yukon due to the extended length of the peak.

The participation and dispatch sequence in such cases must be limited by the risk of creating of a second larger system peak. For example, to mitigate the risk of snapback the total participants may be divided into groups with each group having a different DR event dispatch sequence (i.e. staggering).

Managing participations for the DR measures will need to be carefully processed by the utility, keeping in consideration the combined and interactive impacts of the snapback effect from various capacity DSM assets. If the participation of a single measure, or a group of measures with the same dispatch sequence exceeds past a certain limit, this would have the potential to create a larger peak than present in the original pre-capacity DSM load.

There are a number of technology providers that offer optimization algorithms to get the highest curtailment out of a fleet of devices, while pacing the snapback to avoid creating a second system peak higher than the one the program was intended to avert. Ideally, such systems can manage multiple DR assets in a dynamic manner so that as the number of participants in a DR program increases, the dispatch sequence can be varied to smooth the post-event profile and prevent a rebound event from creating a new, and possibly larger, peak.

2.3.6 Modeled Periods of Peak Shaving & Snapback

In the modelling of snapback, the rate of peak shaving and snapback is assumed to occur at a constant and uniform rate. However, depending on the level of sophistication of the DR solutions and the use of a DRMS, the shaving and snapback effects may be modulated/optimized at a variable rate to meet the real-time needs of the entire YEC grid.

The following table presents the modeled periods of peak shaving and snapback, with details on the type of snapback for each measure category.

Exhibit 48: Modeled Periods of Peak Shaving & Snapback

Measure	Snapback Type	Shaving Hours	Snapback Hours
Space Heating Direct Load Control: • LVCT • Central Air Thermostats	The thermostat set-point can be increased prior to the start of a DR event for pre-heating. There is a rebound effect after DR event to regain thermal energy requirements.	9:00 – 12:00 17:00 – 20:00	07:00 – 08:00 (pre-heating) 13:00 – 14:00 (rebound) 15:00 – 16:00 (pre-heating) 21:00 – 22:00 (rebound)
Storage: • ETS	The ETS is charged and stores energy overnight. Stored Energy is released during the shaving hours specified. Most ETS systems allow for precise charge rates (0-100% wattage) and allow for setting target charge levels (based upon temperature).	10:00 – 22:00	This is not a snapback per-se. The ETS unit are storing heating during the following period 23:00 – 09:00
Water Heater Control: • Grid-Integrated Water Heater	The snapback would be fully controlled after the DR event because the water will remain warm enough to not cause a shortage of hot water in the home. The water heater would catch up overnight during the off-peak period as the average residential consumer is expected to have low usage of DHW during these hours.	10:00 – 22:00	24:00 – 06:00
Embedded Generation	No snapback – with the use of a DRMS system solution and automatic transfer switch there would be a seamless switchover between emergency generator to utility power	10:00 – 22:00	N/A
Other • Behavioural DR Alerts	Behavioural activities across residential customer base expected to vary throughout the DR event, the expected curtailment is minimal and this combined with staggered responses from customers are expected to minimize snapback effects (ie. the effects would be negligible on a system level impact)	10:00 – 22:00	N/A

2.3.7 System Level Peak Curtailment by Measure

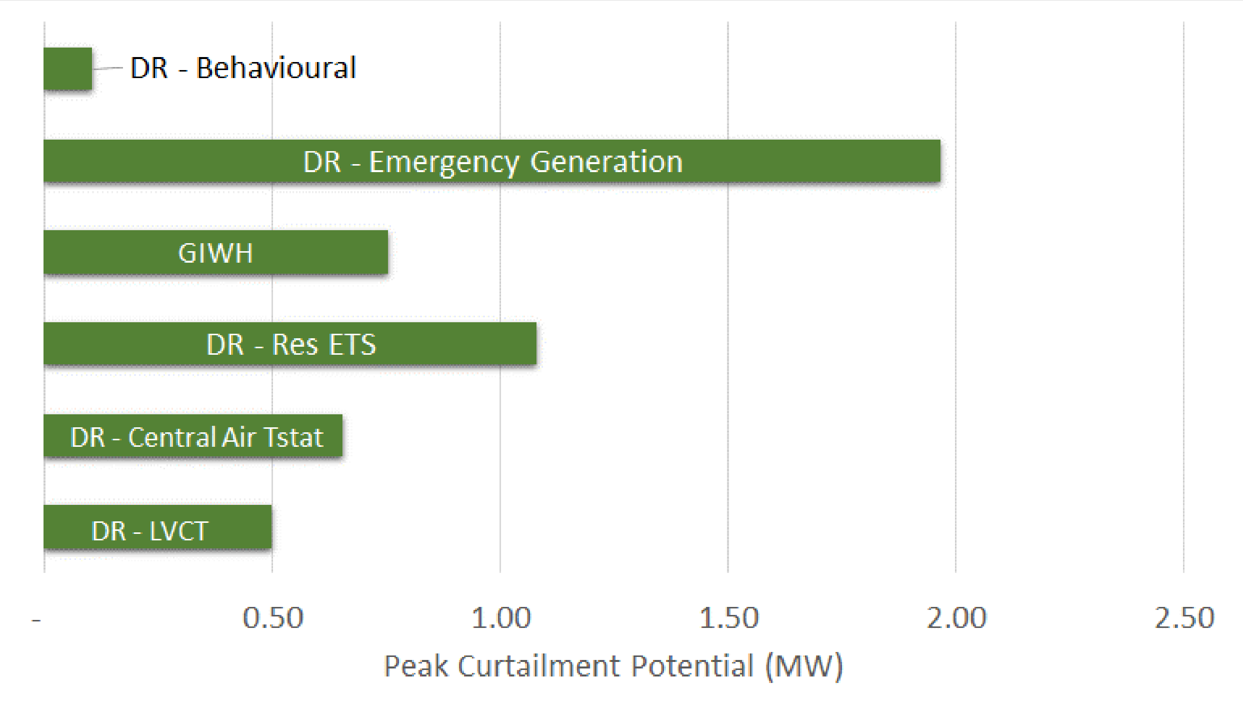
The measure level savings were scaled up and assessed as a simulated DR event (represented using the data from December 30th 2017) for the selected cost-effective measures. In estimating the load impacts, the average load curtailment for each measure was assessed as a block load curtailment during the specified hours of peak shaving and as a block load increase during the snapback periods (refer to the previous section for the modeled periods of shaving and snapback).

The following exhibits (Exhibit 49 and Exhibit 50) present the system level peak curtailment potential from each DR measure, for a cold winter design day:

Exhibit 49: System Level Peak Curtailment & Snapback for Winter Peak Day (MW)

Hour	DR - LVCT	DR - Central Air Tstat	DR - Res ETS	GIWH	DR - Emergency Generation	DR - Behavioural
1	-	-	(1.28)	(1.40)	-	-
2	-	-	(1.28)	(1.40)	-	-
3	-	-	(1.28)	(1.40)	-	-
4	-	-	(1.28)	(1.40)	-	-
5	-	-	(1.28)	(1.40)	-	-
6	-	-	(1.28)	(1.40)	-	-
7	(0.50)	(0.66)	(1.28)	-	-	-
8	(0.50)	(0.66)	(1.28)	-	-	-
9	0.50	0.66	(1.28)	-	-	-
10	0.50	0.66	1.08	0.75	1.96	0.11
11	0.50	0.66	1.08	0.75	1.96	0.11
12	0.50	0.66	1.08	0.75	1.96	0.11
13	(0.50)	(0.66)	1.08	0.75	1.96	0.11
14	(0.50)	(0.66)	1.08	0.75	1.96	0.11
15	(0.50)	(0.66)	1.08	0.75	1.96	0.11
16	(0.50)	(0.66)	1.08	0.75	1.96	0.11
17	0.50	0.66	1.08	0.75	1.96	0.11
18	0.50	0.66	1.08	0.75	1.96	0.11
19	0.50	0.66	1.08	0.75	1.96	0.11
20	0.50	0.66	1.08	0.75	1.96	0.11
21	(0.50)	(0.66)	1.08	0.75	1.96	0.11
22	(0.50)	(0.66)	1.08	0.75	1.96	0.11
23	-	-	(1.28)	-	-	-
24	-	-	(1.28)	(1.40)	-	-

Exhibit 50: Peak Curtailment Potential by Measure



In order to obtain the system level peak curtailment estimates presented above, the measure level curtailment was scaled based upon the expected participation for each DR measure. The assumptions regarding participation are detailed in the main program description for each program. Based on the per-unit curtailment and assumed participation levels, the system level curtailment potential is shown to be the highest for the GIWH, Emergency Generator Control, and residential ETS systems. While the curtailment potential is lower for the web-enabled thermostat measures, the resulting snapback effects in the hours preceding and post the short 4-hour events are insignificant on a system level. The snapback is an important limitation around the maximum curtailment that can be achieved from each of these measures, as it has the potential to create a second peak if the participation of a single measure or group of measures under the same dispatch sequence is too high.

It is important to note that the peak curtailment effects from all measures cannot be summed without accounting for adjustments required to participation under each DM offering and changes to the dispatch schedule to manage the interactive effects of the snapback across multiple DR assets.

Exhibit 51 provides an assessment of the peak curtailment from each DR measure applied to the December 30th 2017 load data (note, the post-DR load values are presented discretely for each measure):

Exhibit 51: Post-DR Load by Measure

Day	12/30/2017						
Hour	**Original Load**	**DR - LVCT**	**DR - Central Air Tstat**	**DR - Res ETS**	**GIWH**	**DR - Emergency Generation**	**DR - Behavioural**
1:00	71.45	71.45	71.45	72.73	72.85	71.45	71.45
2:00	69.96	69.96	69.96	71.24	71.36	69.96	69.96
3:00	69.15	69.15	69.15	70.43	70.55	69.15	69.15
4:00	68.98	68.98	68.98	70.26	70.38	68.98	68.98
5:00	69.29	69.29	69.29	70.57	70.69	69.29	69.29
6:00	70.07	70.07	70.07	71.35	71.47	70.07	70.07
7:00	71.87	72.37	72.52	73.15	71.87	71.87	71.87
8:00	75.42	75.92	76.07	76.70	75.42	75.42	75.42
9:00	78.69	78.19	78.03	79.97	78.69	78.69	78.69
10:00	82.31	81.81	81.66	81.23	81.56	80.35	82.21
11:00	84.45	83.95	83.80	83.37	83.70	82.49	84.35
12:00	83.35	82.85	82.70	82.27	82.60	81.39	83.25
13:00	82.99	83.49	83.64	81.91	82.23	81.02	82.88
14:00	82.11	82.61	82.76	81.03	81.35	80.14	82.00
15:00	81.82	82.32	82.47	80.74	81.06	79.85	81.71
16:00	82.07	82.57	82.73	80.99	81.32	80.11	81.97
17:00	84.30	83.80	83.64	83.22	83.54	82.33	84.19
18:00	86.04	85.54	85.38	84.96	85.28	84.07	85.93
19:00	85.32	84.82	84.67	84.24	84.57	83.36	85.22
20:00	85.45	84.95	84.80	84.37	84.70	83.49	85.35
21:00	83.45	83.95	84.10	82.37	82.69	81.48	83.34
22:00	81.37	81.87	82.03	80.29	80.62	79.41	81.27
23:00	78.83	78.83	78.83	80.11	78.83	78.83	78.83
0:00	75.73	75.73	75.73	77.01	77.13	75.73	75.73
Max Peak:	86.04	85.54	85.38	84.96	85.28	84.07	85.93
Peak Reduction:		**0.50**	**0.66**	**1.08**	**0.75**	**1.96**	**0.11**

This exhibit illustrates how the post-DR load is reduced during the specified shaving hours (for example, the original peak load of 86.04 MW at 6:00 pm is reduced to 84.96 with the ETS releasing stored energy at this time) and increased during the specified snapback hours (for example the original load of 75.73 MW is increased to 77.13 MW with the GIWH regaining thermal energy overnight). For each of the measures, the modeled snapback does not exceed the original load maximum of 86.04 MW. However, the snapback could have the potential to exceed this original load maximum if the combined DR assets are not appropriately staggered or cycled.

2.4 Recommended Capacity DSM Programs for Yukon

Based on the feasibility assessment of the capacity DSM options, the finalized list of measures was categorized into the following capacity DSM program solutions in 2019. These proposed programs were revisited in 2021 with updated avoided cost values and were re-prioritized based on their updated cost-effectiveness results. The conclusions and recommendations are presented in Exhibit 52. Two additional program offerings were developed in 2021 in response to new electrification programs offered by the Energy Branch: Dual Fuel Demand Response (see Section 3.3) and Demand Response EV Charging (see Section 3.4).

Exhibit 52: Recommended Capacity DSM Programs for Yukon

Program Name	Description with Eligible Technologies & Measures	2021 Review and Conclusion
InCharge Peak Alerts *(Behavioural Demand Response Program)*	This is a proposed behavioural DR pilot program to be delivered in parallel with the proposed DSM behavioural HER program. This pilot program will target all residential customers in the Yukon Integrated System. Measures under this pilot program would include: • Text/Email Message Alerts	This proposed program was not cost-effective in the revised test and was therefore removed from consideration.
InCharge Flexible Heating *(Demand Response Direct Load Control Program)*	This is a proposed direct load control DR pilot program to target all YEC residential customers. Measures under this pilot program would include: • Grid Integrated Domestic Hot Water System (GIWH) • Line Voltage Connected Thermostats (LVCT) • Central Air Web Enabled Thermostats • Grid-Interactive Electric Thermal Storage Room Units (ETS)	YEC delivered the Peak Smart Pilot in 2019-2021, which included LVCTs and non-instrumented electric water heater controllers. ICF recommends a full program (referred to as "Residential Demand Response" Program in this report, see Section 3.1). • GIWH was removed from consideration as it is more complex than the other utility-controlled DHW measures • ETS was removed from consideration at this time, but YEC will collaborate with the learnings from the ETS pilot being conducted by the Yukon Conservation Society and revisit

		including an ETS offering based on their findings.
InCharge Commercial DR *(Commercial DR)*	This is a proposed embedded generation control pilot program to target certain YEC commercial customers with back-up diesel emergency generators. Measures under this pilot program include: • Emergency Generator Control	Referred to as Commercial Demand Response Program in this report, see Section 3.5.

The program descriptions in the main body of the report provides a full overview for the specifics of each pilot program including: program description, target market, program implementation activities, impacts, cost-effectiveness, incentives, and budget.

Appendix B Programs Removed from the 2021 Portfolio Design

The following programs were designed in 2018/2019, but were removed from the proposed portfolio in 2021 after assessing the level of duplication with current Energy Branch offering as well as the updated cost-effectiveness results with current avoided cost data. They are included here for future reference.

1 Residential Programs

This section presents the cost-effectiveness test results for the residential programs removed from the 2021 Portfolio Design, followed by descriptions of each of the programs.

Exhibit 53: Cost-effectiveness by Program for a 3-Year Period

Program Name	TRC	UCT	PC	RIM	Levelized Cost ($/kWh)	Levelized Cost ($/kW)
InCharge Home Heating	0.4	0.8	2.3	0.4	$0.12	$465
InCharge Whole Home	0.6	1.0	8.7	0.3	$0.07	$531
InCharge Whole Home for Low-Income	0.3	0.4	3.4	0.2	$0.14	$1,267
InCharge Home Energy Report	0.2	0.4	NA	0.2	$0.12	$716
InCharge Winter Peak Alerts	0.6	0.6	1.0	0.6		$411

1.1 InCharge Home Heating

Non-Dispatchable Capacity & Energy Savings

1.1.1 Program Description

The proposed program is a residential heating, ventilation and air-conditioning (HVAC) program, a common type of DSM program in North America. The Program will focus on providing mail-in rebates for energy efficient equipment that requires the involvement of a contractor, such as water heaters.

There is no duplication between the proposed InCharge Home Heating and the Energy Branch's Good Energy Program. Different residential measures are eligible for each of the programs. For example, the heat pumps eligible for rebates in the Good Energy Heating Systems Program are excluded from InCharge Home Heating.

InCharge Home Heating will encourage the sale/purchase and installation of energy efficient heating and ventilation measures in households through prescriptive rebates. Measure will include: domestic hot water equipment, residential energy recovery ventilation and web-enabled advanced thermostats.

This program provides an opportunity for YEC to diversify the focus of the program administrator to include contractors (while still continuing to offer rebates directly to customers). YEC could collaborate with contractors to promote the Program to their customers by actively engaging with a local network water heater and heating/ventilation contractors, training/ on-boarding them on the Program, and developing collateral materials that they can use to promote the Program.

Contractors will have the option to fill out applications forms and generate the paperwork on behalf of their customers. As per the current Energy Branch offering, customers will still be eligible to complete the application forms on their own if they wish to do so without the support of a contractor. Incentive cheques will continue to be sent to customers regardless of whether the forms have been filled out by the contractor or directly by the customer. The additional level of outreach to include contractors and the collaboration with contractors is expected to boost participation and generate a change of contractor practice.

Residential contractors are critical partners of HVAC programs because the contractors are generally more knowledgeable regarding energy efficient home heating and DHW equipment options, they have a great degree of influence over the choice of system made by the home owners and, ultimately, on enrolling their customers into heating programs. Contractors have the most influence because they have the unique opportunity of having face-to-face meetings with the home owners at a critical moment when the home owners must make a choice regarding their home's mechanical systems. Contractors can also fill out program participation applications more easily than most customers.

There are multiple benefits to contractors enhancing the Program offering. For customers, participation in the program is easier and faster, which lead to higher customer satisfaction. For contractors, they benefit from the Program from upselling equipment, and gain a marketing edge over their competition not only in terms of sales but also in term of staff retention. Engaging contractors helps to build capacity, alter stocking habits, and ultimately transform the residential heating and ventilation market.

In addition to contractor-focused activities, the program administrator will also promote the program through media buys, direct installs, contractor breakfast events, cross-promotion through other programs and other mass-marketing means. Marketing activities to promote the program to customers will continue to operate as per the current program offering. These activities are necessary keep both contractors and customers interested. Contractors will see mass-market marketing as an attractive reason to be associated with the program boost.

1.1.2 Target Market

InCharge Home Heating will target all residential customers within the Yukon Integrated System. This includes detached homes and town houses, semi-detached and some suites within multi-unit residential buildings. Only the customer of YEC or ATCO can sign off on a participation form, but a renter may elect to provide the name and address of a landlord as recipient of the incentive. Contractors or suppliers offering leased heating equipment cannot benefit directly from the rebate, but the customer is still eligible for the rebate if leased equipment meet the technical eligibility criteria.

Contractors that qualify for the program may be required to complete an on-boarding training program. At a minimum, the participating contractors will be required to have all permits and licenses in good standing, as well as industry-standard insurances – no more or no less than required by locals, laws and regulations. With a standard qualification guideline and procedure for all contractors, the program will allow for inclusivity to all interested contractors.

We propose to have small businesses that use residential-grade water heating equipment eligible for this Program as well. Such incentive delivery would be tracked accordingly to distinguish between residential and general service participants to ensure proper cost allocation for future rate design. Participation from general services customers, however, is expected to be relatively low.

1.1.3 Approach to Implementation

YEC will act as the program administrator. YEC will engage with local contractors and to develop the trade relationships needed for the enhancement of the current offering.

YEC will collaborate with the Yukon Conservation Society for customer outreach and marketing to boost the current level of customer outreach under the Good Energy program. The Energy Branch and YEC will collaborate with HVAC distributors, the Yukon Contractors Association and the Whitehorse Chamber of Commerce to engage with heating and ventilation contractors.

YEC will exclusively fund incentives toward electricity conservation measures.

1.1.4 Eligible Technologies and Measures

The proposed initial measures, incentive levels, and projected participation levels are presented below:

Exhibit 54: Initial Measures List with Incentive Levels

Measure Code	Measure Name	Unit Definition	Incentive Level per unit
YEC0093	Web-enabled Advanced Thermostat - Central Air Furnace	per unit	85.00
YEC0094	ENERGY STAR Water Heater	per unit	700.00
YEC0095	Three Element Water Heater	per unit	160.00
YEC0097	Energy Recovery Ventilation	per 100 CFM	375.00

Exhibit 55: Measure Level Participation Projections

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0093	Web-enabled Advanced Thermostat - Central Air Furnace	per unit	16	9	8
YEC0094	ENERGY STAR Water Heater	per unit	32	19	15
YEC0095	Three Element Water Heater	per unit	64	38	30
YEC0097	Energy Recovery Ventilation	per 100 CFM	16	16	16

1.2 InCharge Whole Home

Non-Dispatchable Capacity & Energy Savings

1.2.1 Program Description

The proposed program is a whole-home program, a common type of DSM program, that will realize electricity savings by including free home energy kits and direct install measures. The Program can build on the pre-existing Energy Assessment program by offering additional electrical savings on a direct install basis or can be delivered separately.

The current Existing Home Rebate offering from the Energy Branch includes a home assessment as a pre-qualification step. Prior to applying for an insulation rebate, residential customers are required to complete a renovation upgrade service visit with an NRCan-certified CEA. The energy advisor service consists of trained energy auditors visiting homes to assess opportunities for home insulation measures.

Individuals who pursue home energy assessments are generally interested in receiving a variety of recommendations for how to save energy and would likely be receptive to low cost and minimally intrusive direct install measures. Furthermore, the direct install addition allows the customer to commit to the initial site visit without committing to pursue capital-intensive measures immediately.

Duplication would need to be avoided between the proposed InCharge Whole Home and the Energy Branch's Good Energy Program through the program delivery approach. The Energy Branch does not offer a direct install program. Some of the proposed measures are currently included in the Energy Branch's Quick Start Home Energy Kit, but these kits are not widely distributed. Collaboration and coordination between YEC and the Energy Branch could create a more streamlined experience for participants and could reduce cost of acquisition of participants for both program administrators. Two suggested approaches to delivering InCharge Whole Home are provided below:

1 [**Coordinated offering**] YEC works with the Energy Branch to expand the scope of the home energy assessments to look for additional energy efficiency opportunities, such as lighting upgrades, DHW pipe wraps, faucet aerators, advanced power strips and weather stripping (for electrically-heated homes). The home energy advisor will perform the direct installation of relevant electricity conservation measures on the spot at no cost to the participant; this is an approach known as "direct install". If it is not possible for the energy advisor to install the measures directly, the homeowner may instead be provided with a free home energy kit for the self-installation of certain measures. The home energy advisor will continue to provide the homeowner with a renovation upgrade report as per the current offering, however the boosted report will include recommendations for additional/deeper retrofit measures.

2 [**Independent offering**] YEC delivers InCharge Whole Home completely independently of the Good Energy Existing Home Rebate Program. InCharge Whole Home participants request a visit from a local energy advisor through YEC's program website and the energy advisor performs a walk through audit (not a full blower door test) and installs relevant electricity conservation measures on the spot at no cost to the participant. In addition, the advisor will distribute educational materials and cross-promote other programs while interacting with the residents on site, and survey energy-intensive equipment in the households while conducting their visits to complement the data already collected through the residential end-use survey, thereby a better understanding of the Yukon's residential building stock and potentially uncover other potential energy conservation measures

For the second approach (independent offering) ICF suggests the following approach to avoid double-dipping, where a participant tries to receive rebates or incentives on the same project from multiple program offerings:

1. Eligibility criteria to receive a Quick Start Home Energy Kit should specify that the participant must not receive incentives from other sources for the same measures, and eligibility criteria for InCharge Whole Home should stipulate that the participant has not already received a Quick Start Home Energy Kit.
2. Collaboration with the Energy Branch may be required to do periodic spot checks.

1.2.2 Target Market

The Program will target all residential customers in the Yukon Integrated System with an existing home. This includes detached homes and town houses, semi-detached and suites within multi-unit residential buildings (except for common spaces).

The YEC will target customers with greater energy consumption and/or electric space heating through collaboration with ATCO for the use of billing data to maximize potential savings per household.

1.2.3 Approach to Implementation

Assuming YEC will offer the InCharge Whole Home independently, YEC will act as the program administrator. YEC will exclusively fund incentives toward electricity conservation measures.

The Energy Branch and YEC will engage the current pool of NRCan certified energy auditors, who are expected to deliver the site inspections and installations. If required, YEC may contract energy auditors to increase the existing pool of energy advisors available to support this program.

YEC will collaborate with the Yukon Conservation Society and Yukon Housing for outreach and recruitment.

1.2.4 Eligible Technologies and Measures

The proposed initial measures, incentive levels, and projected participation levels are presented below:

Exhibit 56: Initial Measures List with Incentive Levels

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0001	Direct Install - ≤11W ENERGY STAR® Qualified LED A Shape (60W) (minimum 600 Lumen output)	per unit	5.00
YEC0002	Direct Install - ≤11W ENERGY STAR® Qualified LED MR 16 (minimum 400 Lumen output)	per unit	10.00
YEC0003	Direct Install - ≤14W ENERGY STAR® Qualified LED A Shape (75W) (minimum 800 Lumen output)	per unit	5.00
YEC0004	Direct Install - ≤16W ENERGY STAR® Qualified LED PAR 20 (minimum 600 Lumen output)	per unit	5.00
YEC0005	Direct Install - ≤16W ENERGY STAR® Qualified LED PAR30 & PAR38 (minimum 600 Lumen output)	per unit	10.00
YEC0006	Direct Install - ≤23W ENERGY STAR® Qualified LED A Shape (100W) (minimum 1600 Lumen output)	per unit	10.00

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0007	Direct Install - ≤23W ENERGY STAR® Qualified LED PAR (minimum 1100 Lumen output)	per unit	20.00
YEC0008	Direct Install - ≤6W ENERGY STAR® Qualified LED MR 16 / PAR 16 (minimum 250 Lumen output)	per unit	5.00
YEC0009	Direct Install - ENERGY STAR® LED Wet Location Rated PAR lamp ≤ 23 Watt (minimum 1100 Lumen output)	per unit	15.00
YEC0010	Direct Install - LED Downlight with Light Output >600 and <800 lumens (Retrofit Measure List)	per unit	45.00
YEC0011	Direct Install - LED Downlight with Light Output >800 lumens (Retrofit Measure List)	per unit	55.00
YEC0012	Direct Install - Efficient Aerators (Bathroom/Kitchen)	per unit	4.00
YEC0013	Direct Install - Efficient Showerhead (Standard/Handheld)	per unit	10.00
YEC0014	Direct Install - Smart Power Bar with Integrated Timer / Auto Shut-off	per unit	30.00
YEC0015	Direct Install - Hot Water Pipe Wrap	Per 3 ft	2.00
YEC0016	Direct Install - Block Heater Timers	per unit	0.00
YEC0017	Direct Install - Web-enabled Advanced Thermostat - Central Air Furnace	per unit	210.00
YEC0018	Direct Install - WEATHERSTRIPPING (DOOR FRAME)	per unit	15.00
YEC0019	Direct Install - WEATHERSTRIPPING (FOAM OR V-STRIP)	per unit	10.00
YEC0104	OUTDOOR LIGHTING TIMER	per unit	5.00
YEC0105	OUTDOOR MOTION SENSOR	per unit	10.00
YEC0304	Hardwired Exhaust fan Timer	per unit	10.00

Exhibit 57: Measure Level Participation Projections

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0001	Direct Install - ≤11W ENERGY STAR® Qualified LED A Shape (60W) (minimum 600 Lumen output)	per unit	1,093	981	785
YEC0002	Direct Install - ≤11W ENERGY STAR® Qualified LED MR 16 (minimum 400 Lumen output)	per unit	4	4	3
YEC0003	Direct Install - ≤14W ENERGY STAR® Qualified LED A Shape (75W) (minimum 800 Lumen output)	per unit	41	37	30
YEC0004	Direct Install - ≤16W ENERGY STAR® Qualified LED PAR 20 (minimum 600 Lumen output)	per unit	1	1	1
YEC0005	Direct Install - ≤16W ENERGY STAR® Qualified LED PAR30 & PAR38 (minimum 600 Lumen output)	per unit	9	8	6

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0006	Direct Install - ≤23W ENERGY STAR® Qualified LED A Shape (100W) (minimum 1600 Lumen output)	per unit	101	91	73
YEC0007	Direct Install - ≤23W ENERGY STAR® Qualified LED PAR (minimum 1100 Lumen output)	per unit	5	5	4
YEC0008	Direct Install - ≤6W ENERGY STAR® Qualified LED MR 16 / PAR 16 (minimum 250 Lumen output)	per unit	8	7	6
YEC0009	Direct Install - ENERGY STAR® LED Wet Location Rated PAR lamp ≤ 23 Watt (minimum 1100 Lumen output)	per unit	2	2	1
YEC0010	Direct Install - LED Downlight with Light Output >600 and <800 lumens (Retrofit Measure List)	per unit	2	2	1
YEC0011	Direct Install - LED Downlight with Light Output >800 lumens (Retrofit Measure List)	per unit	1	1	1
YEC0012	Direct Install - Efficient Aerators (Bathroom/Kitchen)	per unit	160	160	129
YEC0013	Direct Install - Efficient Showerhead (Standard/Handheld)	per unit	135	135	108
YEC0014	Direct Install - Smart Power Bar with Integrated Timer / Auto Shut-off	per unit	291	291	234
YEC0015	Direct Install - Hot Water Pipe Wrap	Per 3 ft	30	30	24
YEC0016	Direct Install - Block Heater Timers	per unit	13	13	10
YEC0017	Direct Install - Web-enabled Advanced Thermostat - Central Air Furnace	per unit	18	18	14
YEC0018	Direct Install - WEATHERSTRIPPING (DOOR FRAME)	per unit	35	74	88
YEC0019	Direct Install - WEATHERSTRIPPING (FOAM OR V-STRIP)	per unit	35	74	88
YEC0104	OUTDOOR LIGHTING TIMER	per unit	-	-	-
YEC0105	OUTDOOR MOTION SENSOR	per unit	121	304	274
YEC0304	Hardwired Exhaust fan Timer	per unit	211	211	169

1.3 InCharge Whole Home for Low-Income Households

Non-Dispatchable Capacity & Energy Savings

1.3.1 Program Description

The proposed Program is a low-income energy efficiency program, a common type of DSM program. The Program is developed as a second track to the InCharge Whole Home Program. The Program will offer the same energy assessment and direct install measure and will be propelled by the same trained energy auditors. The auditor will visit homes to assess the energy savings opportunities. The InCharge Whole Home for Low-Income Households will waive the $50 fee for the home energy assessment.

In addition to waiving the cost for the site visits, InCharge Whole Home for Low-Income Households will differ from InCharge Whole Home in that only low-income households will be eligible. For low-income households, the program will increase the number of direct install measures that participants will be eligible for. Furthermore, participants in the will be directed to Yukon Housing's pre-existing loan program (a low interest rate financing program), which they will be able to leverage to fund costly home renovations.

Duplication would need to be avoided between the proposed InCharge Whole Home for Low-Income Households and the Energy Branch's Good Energy Program, by the target audience and the program delivery approach. The Energy Branch does not currently offer a program targeted to low-income households. It also does not offer a direct install program.

InCharge Whole Home for Low-Income Households increases the access to DSM for low-income households. Low-income households typically have greater need for energy improvements as they often lack the resources to purchase new efficient appliances and lightbulbs, and often live in poorly insulated homes in need of repair. As such, the electricity savings potential is typically higher than that for regular homes. However, the need for financial support to realize savings is also higher. In most low-income DSM programs, program administrators and their respective utilities commissions agree to higher spending relative to the savings. Low-income programs offer relief to those who are most impacted by rate increases resulting from new infrastructure spending and DSM spending. Finally, low-income households often do not have the means to participate in regular energy efficiency programs. A low-income program is meant to address that gap and ensure fairness in the distribution of DSM benefits.

During site visits, the auditors will perform a walk-through audit (not a full blower door test) and install relevant electricity conservation measures on the spot at no cost to the participant. In addition, the advisor will distribute educational materials and cross-promote other programs while interacting with the residents on site, and survey energy-intensive equipment in the households while conducting their visits to complement the data already collected through the residential end-use survey, thereby a better understanding of the Yukon's residential building stock and potentially uncover other potential energy conservation measures.

We suggest the following approach to avoid double-dipping, where a participant tries to receive rebates or incentives on the same project from multiple program offerings:

1. Eligibility criteria should specify that the participant must not receive incentives from other sources for the same project
2. Collaboration with the Energy Branch would be required to do periodic spot checks.

1.3.2 Target Market

The Program will target all residential households in the Yukon Integrated System who have a proven income lower than the low-income cut-off (LICO) living in an existing home. A pre-existing program may be necessary to prove LICO. Detached homes, semi-detached and town houses, and suites within multi-unit residential buildings will all be eligible under the program. Residents in buildings owned by Yukon Housing will not be eligible.

YEC will target customers with greater energy consumption and/or electric space heating through collaboration with ATCO the use of billing data to maximize potential savings per household.

1.3.3 Approach to Implementation

YEC will act as the program administrator. YEC will exclusively fund incentives toward electricity conservation measures. The Energy Branch with the support of YEC will contract with equipment suppliers to procure direct install measures.

YEC will collaborate with Yukon Housing and the Anti-Poverty Coalition to train the energy auditors on how to engage with low-income households.

YEC will collaborate with Yukon Housing and the Anti-Poverty Coalition to identify low-income households. For instance, certain community events and neighborhoods could be targeted in priority.

YEC will partner with the Anti-Poverty Coalition or potentially Yukon Housing to verify the compliance of participants with the LICO test. Alternatively, participants may be asked to identify as a low income household, which would be later verified against the available database of low income housing customers with Yukon Housing or other low income programming.

1.3.4 Eligible Technologies and Measures

The proposed initial measures, incentive levels, and projected participation levels are presented below:

Exhibit 58: Initial Measures List with Incentive Levels

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0039	Direct Install - ≤11W ENERGY STAR® Qualified LED A Shape (60W) (minimum 600 Lumen output)	per unit	5.00
YEC0040	Direct Install - ≤11W ENERGY STAR® Qualified LED MR 16 (minimum 400 Lumen output)	per unit	10.00
YEC0041	Direct Install - ≤14W ENERGY STAR® Qualified LED A Shape (75W) (minimum 800 Lumen output)	per unit	5.00
YEC0042	Direct Install - ≤16W ENERGY STAR® Qualified LED PAR 20 (minimum 600 Lumen output)	per unit	5.00
YEC0043	Direct Install - ≤16W ENERGY STAR® Qualified LED PAR30 & PAR38 (minimum 600 Lumen output)	per unit	10.00
YEC0044	Direct Install - ≤23W ENERGY STAR® Qualified LED A Shape (100W) (minimum 1600 Lumen output)	per unit	10.00
YEC0045	Direct Install - ≤23W ENERGY STAR® Qualified LED PAR (minimum 1100 Lumen output)	per unit	20.00
YEC0046	Direct Install - ≤6W ENERGY STAR® Qualified LED MR 16 / PAR 16 (minimum 250 Lumen output)	per unit	5.00
YEC0047	Direct Install - ENERGY STAR® LED Wet Location Rated PAR lamp ≤ 23 Watt (minimum 1100 Lumen output)	per unit	15.00
YEC0048	Direct Install - LED Downlight with Light Output >600 and <800 lumens (Retrofit Measure List)	per unit	45.00
YEC0049	Direct Install - LED Downlight with Light Output >800 lumens (Retrofit Measure List)	per unit	55.00

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0050	Direct Install - Efficient Aerators (Bathroom/Kitchen)	per unit	4.00
YEC0051	Direct Install - Efficient Showerhead (Standard/Handheld)	per unit	10.00
YEC0052	Direct Install - Smart Power Bar with Integrated Timer / Auto Shut-off	per unit	30.00
YEC0053	Direct Install - Hot Water Pipe Wrap	Per 3 ft	2.00
YEC0054	Direct Install - DHW Tank Insulation	per unit	40.00
YEC0055	Direct Install - Block Heater Timers	per unit	40.00
YEC0056	Direct Install - Web-enabled Advanced Thermostat - Central Air Furnace	per unit	210.00
YEC0057	Direct Install - WEATHERSTRIPPING (DOOR FRAME)	per unit	15.00
YEC0058	Direct Install - WEATHERSTRIPPING (FOAM OR V-STRIP)	per unit	10.00
YEC0059	Direct Install - ENERGY STAR Clothes Washers	per unit	930.00
YEC0060	Direct Install - ENERGY STAR Clothes Dryers	per unit	1180.00
YEC0061	Direct Install - ENERGY STAR Refrigerators	per unit	870.00
YEC0062	Direct Install - ENERGY STAR Freezer	per unit	680.00
YEC0068	Wall Insulation - Electric heating	per Sq.ft	2.00
YEC0069	Attic Insulation - Electric heating	per Sq.ft	2.00
YEC0070	Basement Insulation - Electric heating	per Sq.ft	2.00

Exhibit 59: Measure Level Participation Projections

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0039	Direct Install - ≤11W ENERGY STAR® Qualified LED A Shape (60W) (minimum 600 Lumen output)	per unit	932	837	669
YEC0040	Direct Install - ≤11W ENERGY STAR® Qualified LED MR 16 (minimum 400 Lumen output)	per unit	4	3	3
YEC0041	Direct Install - ≤14W ENERGY STAR® Qualified LED A Shape (75W) (minimum 800 Lumen output)	per unit	35	32	25
YEC0042	Direct Install - ≤16W ENERGY STAR® Qualified LED PAR 20 (minimum 600 Lumen output)	per unit	1	1	1
YEC0043	Direct Install - ≤16W ENERGY STAR® Qualified LED PAR30 & PAR38 (minimum 600 Lumen output)	per unit	8	7	6
YEC0044	Direct Install - ≤23W ENERGY STAR® Qualified LED A Shape (100W) (minimum 1600 Lumen output)	per unit	87	78	62
YEC0045	Direct Install - ≤23W ENERGY STAR® Qualified LED PAR (minimum 1100 Lumen output)	per unit	5	4	3
YEC0046	Direct Install - ≤6W ENERGY STAR® Qualified LED MR 16 / PAR 16 (minimum 250 Lumen output)	per unit	7	6	5
YEC0047	Direct Install - ENERGY STAR® LED Wet Location Rated PAR lamp ≤ 23 Watt (minimum 1100 Lumen output)	per unit	2	2	1

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0048	Direct Install - LED Downlight with Light Output >600 and <800 lumens (Retrofit Measure List)	per unit	1	1	1
YEC0049	Direct Install - LED Downlight with Light Output >800 lumens (Retrofit Measure List)	per unit	1	1	1
YEC0050	Direct Install - Efficient Aerators (Bathroom/Kitchen)	per unit	12	11	9
YEC0051	Direct Install - Efficient Showerhead (Standard/Handheld)	per unit	7	6	5
YEC0052	Direct Install - Smart Power Bar with Integrated Timer / Auto Shut-off	per unit	6	5	4
YEC0053	Direct Install - Hot Water Pipe Wrap	Per 3 ft	5	5	4
YEC0054	Direct Install - DHW Tank Insulation	per unit	37	33	27
YEC0055	Direct Install - Block Heater Timers	per unit	6	6	5
YEC0056	Direct Install - Web-enabled Advanced Thermostat - Central Air Furnace	per unit	4	4	3
YEC0057	Direct Install - WEATHERSTRIPPING (DOOR FRAME)	per unit	18	37	44
YEC0058	Direct Install - WEATHERSTRIPPING (FOAM OR V-STRIP)	per unit	18	37	44
YEC0059	Direct Install - ENERGY STAR Clothes Washers	per unit	28	25	20
YEC0060	Direct Install - ENERGY STAR Clothes Dryers	per unit	-	-	-
YEC0061	Direct Install - ENERGY STAR Refrigerators	per unit	28	25	20
YEC0062	Direct Install - ENERGY STAR Freezer	per unit	-	-	-
YEC0068	Wall Insulation - Electric heating	per Sq.ft	76	68	55
YEC0069	Attic Insulation - Electric heating	per Sq.ft	2,569	2,305	1,844
YEC0070	Basement Insulation - Electric heating	per Sq.ft	169	151	121

1.4 InCharge Home Energy Report

Dispatchable Capacity Program

1.4.1 Program Description

YEC proposes to launch and operate a new home energy reports (HER) program, the InCharge Home Energy Report program. HER programs are a ubiquitous form of residential behavioural DSM that aims to influence household habits and decision making on energy consumption through quantitative and/or graphical feedback on consumption.

There is no duplication between the proposed InCharge Home Energy Report and the Energy Branch's Good Energy Program. The Energy Branch does not offer any behavioural DSM programs.

HER programs operate on social science theories of behaviour change and the principles of feedback and social norms comparison. Reports are sent through mail or email to residential customers periodically. These reports compare the households' energy use to that of similar homes. When exposed to such comparison, participants tend to reduce their consumption in order to fall in line with their neighbours. Many of participants that performed well in the first place typically get excited by the reports. They have been shown to encourage many participants to perform better by appealing to their spirit of competitiveness.

The key component of the reports is the normative-comparative reporting component, which is the part that has been demonstrated to be effective. That part of the report typically requires relatively little space, leaving much space for additional content. Reports also typically include a summary of recent and historical energy usage, energy-efficiency tips, as well as customer communication and cross-promotional content. YEC, ATCO, the Energy Branch and/or other interested partners would be keen to make use of the remainder of the space to engage with customers and cross promote other regular DSM and capacity DSM programs. The ability to add (uncritical) customer engagement content in the reports is an attractive feature of HER programs and the reason why ATCO is interested in enabling the Program.

YEC proposes an opt-out HER program design (i.e. all suitable residential accounts would be enrolled by default unless they opt-out) to capture as many residential accounts as possible across which the cost of the HER platform can be amortized. The fixed cost of deploying a HER technology solution is substantial, and there is a need to enroll as many of the Yukon residential customers as possible to achieve acceptable cost-effectiveness. Residential customers will be properly warned before being sent a first report. Opt-outs are important to YEC, ought to be respected, and will be handled with care.

YEC's HER program will send reports to customers mostly during the summer shoulder season and the winter (October to March). The period leading to winter is when households ought to winterize their house, clean their filters and set their thermostat. Winter is when most electricity is being used in Yukon. This is the most appropriate period to send reports to maximize impact.

The proposed DSM behavioural HER program can be delivered in parallel with a behavioural DR program. The DR program would consist of sending emails and – more importantly – SMS text messages to customers during a DR period. SMS messages would only be sent on an opt-in basis to customers who provided their contact information.

1.4.2 Target Market

The Program will target all residential customers in the Yukon Integrated System. Reports will be delivered on an opt-out basis. Some residential accounts may not be suitable for HERs based on availability of building characteristic data or unusual pattern in their energy usage.

1.4.3 Approach to Implementation

YEC will deliver the HER program. YEC will collaborate with ATCO to access residential electricity consumption data and contact information. YEC and ATCO have had preliminary discussions and ATCO was supportive of the program concept. YEC will retain a HER technology supplier to deliver a solution. This will include: developing behavioral reports, analyzing data, and sending reports. YEC must select a seasoned HER provider and follow standard practice to ensure that savings will be realized.

ATCO will collaborate with YEC and the designated HER technology supplier. ATCO will be required to allow database integration between their billing database and YEC's chosen vendor. The chosen vendor will be liable and ought to prevent any external party, including YEC and the Energy Branch, to access to the billing data.

Other parties such as the Energy Branch or the Yukon Conservation Society will be allowed to promote the program if wished.

YEC and ATCO may, from time to time, allow other collaborating parties, such as the Energy Branch, the Yukon Conservation Society and Yukon Housing, to provide content for the reports.

The proposed method of delivery for home energy reports will provide customers with the option to receive reports online or by paper. For customers that have enrolled to view their bills online via ATCO's 'MyAccount' portal, the HER will be accessible within the same portal (provided that the support of ATCO as a collaboration partner can be obtained).

1.4.4 Eligible Technologies and Measures

The measures associated with implementing a behavioral HER program differ from a typical DSM programs. For the DSM HER program, the treatment will be delivered via email and / or paper postal mail. The projected participation (on an opt-out basis) is presented below:

Exhibit 60: Measure Level Participation Projections

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0100	Home Energy Reports	per home	11,542	11,759	11,981

1.5 InCharge Winter Peak Alerts

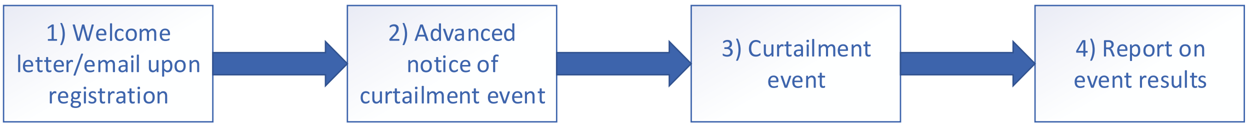
Dispatchable Capacity Program

1.5.1 Program Description

InCharge Winter Peak Alerts is a behavioural demand response pilot program that will encourage participants to reduce their energy usage during demand response curtailment periods, by providing tips and tricks, and education on the environmental impacts and system benefits associated to reduced peak consumption. The program would be delivered in conjunction with the InCharge Home Energy Reports (HER) Program, proposed as a potential program under the Residential Programs section of this document. Through the HER program, participants would have the option to opt-in for the demand response component which would enable the YEC to include them in DR events. Notification would be delivered to participants using various channels of communication to appeal to customers to curtail usage, most commonly using text message or email notifications, however, some solution providers also use apps or 'voice assistant' technology to engage participants through these platforms.

There is no duplication between the proposed InCharge Winter Peak Alerts and the Energy Branch's Good Energy Program. The Energy Branch does not offer any behavioural programs.

Generally, participation in these programs involves the following steps:



1 Welcome Letter: Upon registering, participants are provided with a welcome letter or email to explain the program.

2 Advanced Notice: Notices are generally sent to participants a day, then an hour, in advance of a curtailment event to remind people to reduce consumption leading up to an event.

3 Curtailment Event: During curtailment events, utilities realize between 1.5% to 3% demand reduction that is attributed to the program.

4 Report on Event Results: Based on individual usage data, a follow-up report is provided to participants to provide a summary of how they performed during the event. For demand response events 'neighbourhood comparison reports', that compare individual usage and rank participants relative to similar homes in their neighbourhood, are often used to encourage behavior change.

A number of solutions providers offer the analytics platforms to enable utilities to deliver these programs, to name a few; Bidgely, O Power, Lightspark, EnergyX Solutions, Powerley, and PlanetEcosystems. The platforms ingest granular utility meter data and analyze this data to provide insights to customers which encourage them to reduce energy usage by identifying how loads in the house could be curtailed. A number of social science principles are employed to influence behaviour, including; feedback on usage, social normative comparison, gamification of events (games, prizes), prompts, loss aversion, competition, public commitment, and goal setting. These programs use randomized control trials to attempt to quantify the energy curtailment achieved by each participant when a demand response event occurs. These technology platforms and customer engagement programs consistently achieve between 1.5% and 3% curtailment when events take place.

Given advanced metering infrastructure is currently not available in the Yukon, the following limitations must to be considered:

- First, it would not be possible to quantify the demand savings achieved by participants during a curtailment event, and detailed measurement and verification of program results would not be possible. These types of programs have consistently achieved results, and the proposed program would rely on similar strategies. So a deemed savings approach is recommended, whereby it is assumed the program would have a similar level of influence on those subject to the utility's engagements through the platform.
- Second, feedback on individual performance following a curtailment event could not be provided to participants. Energy use curtailment is frequently attributed to these personalized insights, involving behavioural principles of feedback, social comparison, goal setting. However, other behavioural principles, such as gamification and public commitment, are also considered a driving factors for behavior change in these programs and could be employed to engage people in absence of granular meter data. The YEC could offer random draws for enrollment or for sharing of stories on social media about how energy use was curtailed, offering energy efficient smart home appliances as rewards for participation. There are alternative engagement strategies that could be employed to influence behaviour in absence of advanced analytical insights.

1.5.2 Target Market

The target market for this program includes all participants of the InCharge Homes Energy Reports program.

1.5.3 Approach to Implementation

This program is only recommended if coupled with the InCharge Home Energy Reports program. If the incremental cost of the demand response messaging functionality does not exceed acceptable cost-effectiveness thresholds, as outlined in the sensitivity analysis below.

The cost of the technology platforms required to deliver these programs varies but based on a suite of recently evaluated Canadian utility programs, delivery costs range from $2.3 to $5MM. Based on informal estimates provided by these service providers the cost to setup a platform would range between $600K to $1MM. Given there is currently no advanced metering infrastructure (AMI) in the Yukon the functionality of these platforms would be limited in the context of demand response, and it would not be possible to verify savings that are achieved.

A primary requirement for rigorous analytics in other utility programs is so that they can meet the measurement and verification requirements utilities they are held to by regulators, which enables them to recover the costs associated to program delivery. However, now that a number of programs have demonstrated savings are achievable and that people respond to these engagement strategies the Yukon should consider implementing a similar program despite the lack of granular meter data to generate robust measurement and verification results that require randomized control groups.

Rather than rely on advanced analytics and household specific insights the proposed program would provide generic insights based on typical household consumption and follow best-practices from other programs in terms of tips and trick and educational information that is provided to customers. Because best practices from establish behavioural DR programs would be applied it is anticipated similar outcomes could be achieved.

1.5.4 Eligible Technologies and Measures

The proposed measure under this program with projected participation levels is presented below:

Exhibit 61: Measure Level Participation Projections

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0284	Text Message Alert	per home	855	855	855

2 Commercial Programs

This section presents the cost-effectiveness test results for the commercial programs removed from the 2021 Portfolio Design, followed by descriptions of each of the programs.

Exhibit 62: Cost-effectiveness by Program for a 3-Year Period

Program Name	TRC	UCT	PC	RIM	Levelized Cost ($/kWh)	Levelized Cost ($/kW)
InCharge Commercial Retrofit	0.5	1.3	2.8	0.4	$0.05	$428
Small Business Energy Assessment	0.4	0.5	3.5	0.3	$0.15	$810
Super-Insulated New Buildings	0.9	1.2	7.4	0.2	$0.03	$158
Street Lighting Upgrade	0.4	0.6	1.9	0.3	$0.00	$698

2.1 InCharge Commercial Retrofit

Non-Dispatchable Capacity & Energy Savings

2.1.1 Program Description

The proposed InCharge Commercial Retrofit program is a commercial prescriptive incentive program, a very common type of DSM program that will be offered to all general service customers on the Yukon Integrated System that own or operate existing commercial buildings. Herein, “commercial” will refer to both businesses and institutional/government customers in all general services rate classes.

Duplication would have to be avoided between the proposed InCharge Commercial Retrofit and the Energy Branch’s Good Energy Program upgrades and retrofit rebates for commercial and institutional buildings by the program delivery approach. The Energy Branch does not currently offer prescriptive incentives to commercial and institutional buildings.

Under the existing Good Energy Program, rebates are offered for a variety of listed upgrade measures for existing commercial and institutional customers, and the Energy Branch is also open to reviewing and approving any measures that are not currently listed. The rebate amount is based on a percentage of eligible project costs, and require pre-approval for projects with a proposed rebate value of $5,000 or more. Participants must also provide 3 years of fuel and electric bills with their application. This can be an onerous process for commercial customers.

By offering prescriptive incentives, the proposed InCharge Commercial Retrofit program will offer simple, easy-to-communicate, low-effort access to financial support. Prescriptive incentives are paid as a flat rate per eligible equipment installed. Typical measures include: lighting and lighting controls, heating and/or ventilation systems, DHW, commercial food service, refrigeration, office equipment and other plug-load equipment.

As is the case with the current commercial program offering from the Energy Branch, the commercial customers interested in participating will have to complete a pre-approval application and submit it to YEC for processing prior to proceeding with the retrofit if the estimated rebate value is equal to or greater than $5,000. After completion of the retrofit, commercial customers will be required to fill out an incentive claim application and provide the base case and project case details. Supporting documentation will be required to prove that eligibility criteria have been met, when necessary. It is common practice in other jurisdictions to waive the base case equipment reporting requirement (i.e. existing equipment details) to access the prescriptive incentives. In continuation with current practice, measures will be DLC or ENERGY STAR compliant, on a pre-qualified list, CSA approved, and comply with local laws and regulations. The YEC will fulfill the incentive directly with the participating building owner or manager.

In general, the program will deploy a number of technical assistance, outreach, and account management approaches targeting both suppliers and electricity end-users which, in addition to the incentives themselves, will minimize market barriers to energy efficiency implementation. These barriers include: lack of understanding about the business case of energy efficiency, and/or lack of awareness of technologies.

The program administrator will stimulate program participation through direct engagement with local building owners and managers. Marketing could also include mail inserts, inserts in newsletters targeting local businesses, engaging with trade allies (lighting and HVAC distributors, as well as local HVAC and electrical contractors), with the Yukon Contractors Association and the Whitehorse Chamber of Commerce, as well as participating in and advertising at local business gatherings.

The Program is expected to generate most of its savings from lighting retrofits as most C&I Custom and Prescriptive incentive programs do. After achieving success with lighting during the two first years of operation, the program will vigorously pursue "non-lighting" measures such as heating, ventilation and DHW to ensure the full potential of a C&I Customer and Prescriptive Incentive program is reached.

We suggest the following approach to avoid double-dipping, where a participant tries to receive rebates or incentives on the same project from multiple program offerings:

1 Eligibility criteria should specify that the participant must not receive incentives from other sources for the same project

2 Collaboration with the Energy Branch would be required to do periodic spot checks.

2.1.2 Target Market

The InCharge Commercial Retrofit program will target all General Service customers (government and non-government) on the Yukon Integrated System.

Commercial prescriptive incentive programs tend to have more successes with larger businesses and organizations. A greater level of participation from these businesses is to be expected. Small businesses will be offered access to DSM benefits through the Small Business Energy Assessment Program.

There is also potential to target agricultural business customers on the Yukon Integrated system with measures specific to agribusiness processes.

2.1.3 Approach to Implementation

The YEC will act as the program administrator. YEC will exclusively fund incentives toward electricity conservation measures.

2.1.4 Eligible Technologies and Measures

The following table presents a list of the prescriptive track measures under the proposed program. It is to be noted that the lighting measures in this list will be assessed for DLC/ENERGY STAR eligibility criteria.

Exhibit 63: Initial Measures List with Incentive Levels

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0111	GS LED lamps - Incandescent equivalent 60W and lower	per bulb	1.00
YEC0112	GS LED lamps - Incandescent equivalent 61 to 150W	per bulb	2.00
YEC0113	Reflector and specialty LED lamps	per bulb	5.00
YEC0114	LED for HID replacement - Lamp being replaced of 70 to 249W	per bulb	25.00
YEC0115	LED for HID replacement - Lamp being replaced of 250W or more	per bulb	40.00
YEC0116	Downlight fixtures & retrofit kits - Small	per fixture	10.00
YEC0117	Downlight fixtures and retrofit kits - 600 to 799 lumens	per fixture	10.00
YEC0118	Downlight fixtures and retrofit kits - 800 lumens or more	per fixture	10.00
YEC0119	LED exit sign	per sign	15.00
YEC0120	Linear fixtures - Less than 3,000 lumens	per fixture	20.00
YEC0121	Linear fixtures - 3,000 to 4,499 lumens	per fixture	35.00
YEC0122	Linear fixtures - 4,500 to 5,999 lumens	per fixture	55.00
YEC0123	Linear fixtures - 6,000 to 7,499 lumens	per fixture	75.00
YEC0124	Linear fixtures - 7,500 lumens or more	per fixture	130.00
YEC0125	Troffer fixtures and retrofit kits - 2x2 troffer	per fixture	35.00
YEC0126	Troffer fixtures and retrofit kits - 1x4 troffer	per fixture	30.00
YEC0127	Troffer fixtures and retrofit kits - 2x4 troffer	per fixture	40.00
YEC0128	LED for FTL replacement - Two feet	per bulb	5.00
YEC0129	LED for FTL replacement - Four feet	per bulb	10.00
YEC0130	LED for FTL replacement - Two feet UL Type B	per bulb	5.00
YEC0131	LED for FTL replacement - Four feet UL Type B	per bulb	10.00
YEC0132	Low-bay & medium-bay & high-bay fixtures and retrofit kits - less than 10,000 lumens	per fixture	75.00
YEC0133	Low-bay & medium-bay & high-bay fixtures and retrofit kits - 10,000 to 14,999 lumens	per fixture	100.00
YEC0134	Low-bay & medium-bay & high-bay fixtures and retrofit kits - 15,000 to 19,999 lumens	per fixture	145.00
YEC0135	Low-bay & medium-bay & high-bay fixtures and retrofit kits - 20,000 lumens or more	per fixture	230.00
YEC0136	LED accent/track lighting fixtures	per fixture	30.00
YEC0137	Horizontal and vertical refrigerated case lighting - Refrigerator	per foot	5.00
YEC0138	Exterior LED fixtures and retrofit kits - Less than 5,000 lumens	per fixture	95.00

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0139	Exterior LED fixtures and retrofit kits - 5,000 to 9,999 lumens	per fixture	145.00
YEC0140	Exterior LED fixtures and retrofit kits - 10,000 to 14,999 lumens	per fixture	195.00
YEC0141	Exterior LED fixtures and retrofit kits - 15,000 lumens or more	per fixture	395.00
YEC0142	Exterior LED wall packs and canopy luminaires - Less than 5,000 lumens	per fixture	95.00
YEC0143	Exterior LED wall packs and canopy luminaires - 5,000 to 9,999 lumens	per fixture	145.00
YEC0144	Exterior LED wall packs and canopy luminaires - 10,000 lumens or more	per fixture	195.00
YEC0148	Interior daylight controls - Fixture mounted dual occupancy and daylight controls	per sensor	45.00
YEC0149	Interior daylight controls - Ceiling or wall remote mounted	per sensor	30.00
YEC0150	Interior daylight controls - Switch or fixture mounted	per sensor	30.00
YEC0151	Interior occupancy controls - Ceiling or remote mounted sensor	per sensor	45.00
YEC0152	Interior occupancy controls - Wall/switch mounted sensor	per sensor	20.00
YEC0153	Interior occupancy controls - Fixture mounted sensor	per sensor	40.00
YEC0154	Interior occupancy controls - Refrigerated or freezer case sensor	per sensor	25.00
YEC0155	Exterior occupancy sensors	per sensor	35.00
YEC0156	High-efficiency furnaces - Efficiency 96% or more	per MBTU/h	5.00
YEC0157	VFD for pumps and motors - 0.10 hp to 4.99 hp	per hp	265.00
YEC0158	VFD for pumps and motors - 5.00 hp to 19.99 hp	per hp	120.00
YEC0159	VFD for pumps and motors - 20.00 hp to 49.99 hp	per hp	95.00
YEC0160	VFD for pumps and motors - 50.00 hp to 99.99 hp	per hp	85.00
YEC0161	Destratification fans	per fan	3055.00
YEC0163	Griddles - Electric - ENERGY STAR® certified	per unit	1180.00
YEC0164	Combination ovens - Electric - ENERGY STAR® certified	per unit	2100.00
YEC0165	Convection ovens - Electric - ENERGY STAR® certified	per unit	545.00
YEC0166	Fryers - Electric - ENERGY STAR® certified	per unit	655.00
YEC0167	Electric hot food cabinets - 16 cft or more - ENERGY STAR® certified	per unit	655.00
YEC0168	Electric hot food cabinets - 10 to less than 16 cft - ENERGY STAR® certified	per unit	985.00
YEC0169	Electric hot food cabinets - 10 cft or less - ENERGY STAR® certified	per unit	820.00

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0170	Steam cookers - Electric - ENERGY STAR® certified	per unit	1360.00
YEC0171	Dishwashers - Undercounter - ENERGY STAR® certified	per unit	65.00
YEC0172	Dishwashers - Single tank door/upright - ENERGY STAR® certified	per unit	420.00
YEC0173	Dishwashers - Single tank conveyor - ENERGY STAR® certified	per unit	1120.00
YEC0174	Demand control kitchen ventilation (DCKV)	per sensor	1085.00
YEC0175	Load sensing plug strips	per unit	10.00
YEC0177	ENERGY STAR Ice Machines	Per unit	260.00
YEC0178	Beverage Vending Machine Controls	per unit	90.00
YEC0179	Open Drip Proof Motors	per HP	10.00
YEC0180	Totally Enclosed Fan-Cooled (TEFC) Motors	per HP	20.00
YEC0181	ENERGY STAR Freezer	per unit	90.00
YEC0182	ENERGY STAR Refrigerator	per unit	90.00
YEC0183	Network PC Power Management Software	per Software	5.00
YEC0184	Refrigeration - ECM motors for evaporator fans for reach-in coolers and freezers	per motor	55.00
YEC0185	Refrigeration - ECM motors for evaporator fans for walk-in coolers and freezers	per motor	55.00
YEC0186	Refrigeration - Anti-sweat heater controls	per door	110.00
YEC0187	Refrigeration - Energy Efficient Case Doors	per foot	70.00
YEC0188	Refrigeration - Cooler Night Curtains, Open Coolers	per foot	25.00
YEC0189	Refrigeration - Strip Curtains for Walk-in Freezers and Coolers	per unit	5.00

Exhibit 64: Measure Level Participation Projections

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0111	GS LED lamps - Incandescent equivalent 60W and lower	per bulb	407	427	438
YEC0112	GS LED lamps - Incandescent equivalent 61 to 150W	per bulb	16	17	18
YEC0113	Reflector and specialty LED lamps	per bulb	169	177	182
YEC0114	LED for HID replacement - Lamp being replaced of 70 to 249W	per bulb	1	1	1

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0115	LED for HID replacement - Lamp being replaced of 250W or more	per bulb	2	2	2
YEC0116	Downlight fixtures & retrofit kits - Small	per fixture	4	4	4
YEC0117	Downlight fixtures and retrofit kits - 600 to 799 lumens	per fixture	10	11	11
YEC0118	Downlight fixtures and retrofit kits - 800 lumens or more	per fixture	37	39	40
YEC0119	LED exit sign	per sign	8	9	9
YEC0120	Linear fixtures - Less than 3,000 lumens	per fixture	14	15	15
YEC0121	Linear fixtures - 3,000 to 4,499 lumens	per fixture	31	33	34
YEC0122	Linear fixtures - 4,500 to 5,999 lumens	per fixture	45	47	48
YEC0123	Linear fixtures - 6,000 to 7,499 lumens	per fixture	16	17	18
YEC0124	Linear fixtures - 7,500 lumens or more	per fixture	48	50	52
YEC0125	Troffer fixtures and retrofit kits - 2x2 troffer	per fixture	67	70	72
YEC0126	Troffer fixtures and retrofit kits - 1x4 troffer	per fixture	70	73	75
YEC0127	Troffer fixtures and retrofit kits - 2x4 troffer	per fixture	174	182	187
YEC0128	LED for FTL replacement - Two feet	per bulb	10	10	11
YEC0129	LED for FTL replacement - Four feet	per bulb	3,807	3,997	4,097
YEC0130	LED for FTL replacement - Two feet UL Type B	per bulb	1	1	1
YEC0131	LED for FTL replacement - Four feet UL Type B	per bulb	439	461	472
YEC0132	Low-bay & medium-bay & high-bay fixtures and retrofit kits - less than 10,000 lumens	per fixture	15	16	17
YEC0133	Low-bay & medium-bay & high-bay fixtures and retrofit kits - 10,000 to 14,999 lumens	per fixture	39	41	42
YEC0134	Low-bay & medium-bay & high-bay fixtures and retrofit kits - 15,000 to 19,999 lumens	per fixture	33	35	36
YEC0135	Low-bay & medium-bay & high-bay fixtures and retrofit kits - 20,000 lumens or more	per fixture	340	357	366
YEC0136	LED accent/track lighting fixtures	per fixture	8	9	9
YEC0137	Horizontal and vertical refrigerated case lighting - Refrigerator	per foot	1	1	1
YEC0138	Exterior LED fixtures and retrofit kits - Less than 5,000 lumens	per fixture	21	22	22
YEC0139	Exterior LED fixtures and retrofit kits - 5,000 to 9,999 lumens	per fixture	15	15	16

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0140	Exterior LED fixtures and retrofit kits - 10,000 to 14,999 lumens	per fixture	10	10	11
YEC0141	Exterior LED fixtures and retrofit kits - 15,000 lumens or more	per fixture	47	50	51
YEC0142	Exterior LED wall packs and canopy luminaires - Less than 5,000 lumens	per fixture	14	15	15
YEC0143	Exterior LED wall packs and canopy luminaires - 5,000 to 9,999 lumens	per fixture	15	15	16
YEC0144	Exterior LED wall packs and canopy luminaires - 10,000 lumens or more	per fixture	9	10	10
YEC0148	Interior daylight controls - Fixture mounted dual occupancy and daylight controls	per sensor	2	2	2
YEC0149	Interior daylight controls - Ceiling or wall remote mounted	per sensor	1	1	1
YEC0150	Interior daylight controls - Switch or fixture mounted	per sensor	1	1	1
YEC0151	Interior occupancy controls - Ceiling or remote mounted sensor	per sensor	1	1	1
YEC0152	Interior occupancy controls - Wall/switch mounted sensor	per sensor	3	3	3
YEC0153	Interior occupancy controls - Fixture mounted sensor	per sensor	21	22	23
YEC0154	Interior occupancy controls - Refrigerated or freezer case sensor	per sensor	1	1	1
YEC0155	Exterior occupancy sensors	per sensor	1	1	1
YEC0156	High-efficiency furnaces - Efficiency 96% or more	per MBTU/h	1	1	1
YEC0157	VFD for pumps and motors - 0.10 hp to 4.99 hp	per hp	1	1	1
YEC0158	VFD for pumps and motors - 5.00 hp to 19.99 hp	per hp	4	4	4
YEC0159	VFD for pumps and motors - 20.00 hp to 49.99 hp	per hp	5	6	6
YEC0160	VFD for pumps and motors - 50.00 hp to 99.99 hp	per hp	5	6	6
YEC0161	Destratification fans	per fan	1	1	1
YEC0163	Griddles - Electric - ENERGY STAR® certified	per unit	2	2	2
YEC0164	Combination ovens - Electric - ENERGY STAR® certified	per unit	2	2	2
YEC0165	Convection ovens - Electric - ENERGY STAR® certified	per unit	2	2	2
YEC0166	Fryers - Electric - ENERGY STAR® certified	per unit	2	2	2

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0167	Electric hot food cabinets - 16 cft or more - ENERGY STAR® certified	per unit	2	2	2
YEC0168	Electric hot food cabinets - 10 to less than 16 cft - ENERGY STAR® certified	per unit	2	2	2
YEC0169	Electric hot food cabinets - 10 cft or less - ENERGY STAR® certified	per unit	2	2	2
YEC0170	Steam cookers - Electric - ENERGY STAR® certified	per unit	2	2	2
YEC0171	Dishwashers - Undercounter - ENERGY STAR® certified	per unit	2	2	2
YEC0172	Dishwashers - Single tank door/upright - ENERGY STAR® certified	per unit	2	2	2
YEC0173	Dishwashers - Single tank conveyor - ENERGY STAR® certified	per unit	2	2	2
YEC0174	Demand control kitchen ventilation (DCKV)	per sensor	2	2	2
YEC0175	Load sensing plug strips	per unit	13	13	14
YEC0177	ENERGY STAR Ice Machines	Per unit	2	2	2
YEC0178	Beverage Vending Machine Controls	per unit	2	2	2
YEC0179	Open Drip Proof Motors	per HP	2	2	2
YEC0180	Totally Enclosed Fan-Cooled (TEFC) Motors	per HP	2	2	2
YEC0181	ENERGY STAR Freezer	per unit	2	2	2
YEC0182	ENERGY STAR Refrigerator	per unit	2	2	2
YEC0183	Network PC Power Management Software	per Software	1	1	1
YEC0184	Refrigeration - ECM motors for evaporator fans for reach-in coolers and freezers	per motor	2	2	2
YEC0185	Refrigeration - ECM motors for evaporator fans for walk-in coolers and freezers	per motor	2	2	2
YEC0186	Refrigeration - Anti-sweat heater controls	per door	2	2	2
YEC0187	Refrigeration - Energy Efficient Case Doors	per foot	2	2	2
YEC0188	Refrigeration - Cooler Night Curtains, Open Coolers	per foot	2	2	2
YEC0189	Refrigeration - Strip Curtains for Walk-in Freezers and Coolers	per unit	2	2	2

2.2 Small Business Energy Assessment Program

Non-Dispatchable Capacity & Energy Savings

2.2.1 Program Description

The Small Business Energy Assessment Program is a small business direct install program, a ubiquitous type of DSM program. The Program will bring energy efficiency benefits to small-business general service customers, which are typically harder to reach. While small businesses are eligible for commercial retrofit incentive programs, they tend to self-select themselves out of these programs because they do not have the resources – both in terms of management and finances – to participate. Small businesses require a more hands-on approach from program administrators and more generous incentives than larger general service customers.

Duplication would need to be avoided between the proposed Small Business Energy Assessment Program and the Energy Branch's Good Energy Program, by the target audience and the program delivery approach. The Energy Branch does not currently offer a program targeted to small businesses. It also does not offer a direct install program.

The Program will consist of a network of electrical and refrigeration contractors under contract with YEC, visiting businesses to deliver conservation measures on a direct-install basis and identifying additional measures of interest for future building renovation. The contractor will charge $100 per site visit to the customer. There would be two types of participants in the program:

Type 1: One-Visit Participation. The contractor will perform one visit to the business and directly install relevant electricity conservation measures on the spot at no cost to the participant: mostly lighting measures, advanced power strips, domestic hot water measures and commercial refrigeration measures. Some measures may require a follow-up visit by the same contractor or by a second contractor for installation, like for instance commercial refrigeration measures. The participant can simply stop after the one visit – that is, a Type-1 Participant -- or may pursue their journey through the Program by expanding the scope of the one initial site visit – a Type-2 Participant.

Type 2: Pre and Post Site Visit Participation. If a participant is keen on proceeding with deeper retrofits, the initial contractor will perform a more thorough inspection of the building and suggest additional lighting, refrigeration, and heat recovery ventilation (HRV) retrofits. Based on test results, the contractor will recommend a suite of additional measures to the Type-2 participant along with eligible incentives to offset the cost of the measures. The participant must have the contractor return to do a post-installation inspection, "post site visit," to confirm the installation of recommended measures. Only then will the Type-2 participant be paid the additional eligible incentive. YEC would fund only incentives associated with electric savings.

The newly proposed Program offers electrical conservation measures (some rebated, and some on a direct-install basis). By offering a one-off site visit approach (Type 1 participation), it will be easy for small businesses to participate. Their initial participation may entice them to pursue their journey in the program with deeper retrofits.

The new Program will take a more pro-active approach to engaging potential participants than past programs. YEC will actively market the program and engage directly with small businesses to boost program participation.

During site visits, the contractors will (1) distribute educational material and cross-promote other programs while interacting with the building operators on site, and (2) survey energy-intensive equipment in small businesses to complement the data collected through the commercial end-use survey, thereby developing a better understanding of the Yukon's commercial building stock and potentially uncover other energy conservation measures.

We suggest the following approach to avoid double-dipping, where a participant tries to receive rebates or incentives on the same project from multiple program offerings:

1 Eligibility criteria should specify that the participant must not receive incentives from other sources for the same project

2 Collaboration with the Energy Branch would be required to do periodic spot checks.

2.2.2 Target Market

The Program will target all General Service customers with a building located in the Yukon Integrated System that consume 15 to 150 MWh per year in one location (one premise ID). Typical sectors that find themselves in the small business category entail: small retailers, restaurants, commercial food services, convenience stores, small offices, community centers, clinics, car dealerships, as well garages and gas stations. YEC can determine whether to exclude chain companies from this program. Chain companies are centrally owned by large corporations and are likely to have corporate support and assistance to pursue DSM that other locally-owned small businesses do not.

Small businesses or organizations operating from homes (residential customers) will not have access to the Small Business Energy Assessment Program. They will, however, have access to the suite of residential programs.

2.2.3 Approach to Implementation

The YEC will act as the program administrator. YEC will exclusively fund incentives toward electricity conservation measures. YEC will procure certified energy auditors who will deliver the site inspections and installations. YEC will contract with contractors (or a network of contractors) to procure direct install measures. Ideally, YEC will work with the Energy Branch and its established Good Energy Network list.

2.2.4 Eligible Technologies and Measures

The proposed initial measures, incentive levels, and projected participation levels are presented below:

Exhibit 65: Initial Measures List with Incentive Levels

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0190	Heat Recovery Ventilation	per 100 CFM	425.00
YEC0191	Advanced Thermostats	per unit	210.00
YEC0192	Strip Curtain Walk-in Cooler	per foot	50.00
YEC0193	Strip Curtain Walk-in Freezer	per foot	50.00
YEC0194	Night Curtains - Coolers	per foot	35.00
YEC0195	LED Case Lighting	per linear ft	20.00
YEC0196	LED A19 Lamps - Over 60W	per lamp	15.00

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0197	LED A19 Lamps - 60W Eqvt. Or lower	per lamp	10.00
YEC0198	Door Gaskets - Walk-In Cooler	per linear ft	5.00
YEC0199	Door Gaskets - Walk-In Freezer	per linear ft	5.00
YEC0200	Door Auto Closers - Walk-In Cooler	per door	230.00
YEC0201	Door Auto Closers - Walk-In Freezer	per door	230.00
YEC0202	ENERGY STAR® Qualified LED PAR 16 pin or screw base, ≤ 6W Minimum 250 Lumen Output	per unit	20.00
YEC0203	ENERGY STAR® Qualified LED MR 16 pin or screw base, ≤ 6W Minimum 250 Lumen Output	per unit	20.00
YEC0204	ENERGY STAR® Qualified LED PAR 16 pin or screw base, ≤ 8W Minimum 400 Lumen Output	per unit	20.00
YEC0205	ENERGY STAR® Qualified LED MR 16 pin or screw base, ≤ 8W Minimum 400 Lumen Output	per unit	20.00
YEC0206	ENERGY STAR® Qualified LED PAR 20, ≤ 7W Minimum 500 Lumen Output	per unit	15.00
YEC0207	ENERGY STAR® Qualified LED BR20, ≤ 7W Minimum 500 Lumen Output	per unit	15.00
YEC0208	ENERGY STAR® Qualified LED PAR 30, ≤ 12W Minimum 600 Lumen Output	per unit	25.00
YEC0209	ENERGY STAR® Qualified LED BR 30, ≤ 12W Minimum 600 Lumen Output	per unit	25.00
YEC0210	ENERGY STAR® Qualified LED PAR 30, ≤ 16W Minimum 800 Lumen Output	per unit	25.00
YEC0211	ENERGY STAR® Qualified LED BR 30, ≤ 16W Minimum 800 Lumen Output	per unit	20.00
YEC0212	ENERGY STAR® Qualified LED PAR 38, ≤ 12W Minimum 600 Lumen Output	per unit	30.00
YEC0213	ENERGY STAR® Qualified LED BR40, ≤ 12W Minimum 600 Lumen Output	per unit	20.00
YEC0214	ENERGY STAR® Qualified LED PAR 38, ≤ 14W Minimum 800 Lumen Output	per unit	30.00
YEC0215	ENERGY STAR® Qualified LED BR40, ≤ 14W Minimum 800 Lumen Output	per unit	20.00
YEC0216	ENERGY STAR® Qualified LED PAR 38, ≤ 19W Minimum 1100 Lumen Output	per unit	30.00
YEC0217	ENERGY STAR® Qualified LED BR40, ≤ 19W Minimum 1100 Lumen Output	per unit	25.00
YEC0218	ENERGY STAR® Qualified LED A Shape, ≤ 9W Minimum 450 Lumen Output	per unit	15.00

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0219	ENERGY STAR® Qualified LED A Shape, ≤ 11W Minimum 800 Lumen Output	per unit	15.00
YEC0220	ENERGY STAR® Qualified LED A Shape, ≤ 16W Minimum 1200 Lumen Output	per unit	20.00
YEC0221	ENERGY STAR® Qualified LED Decorative Bulb E12 Candelabra or E26 Base, ≤ 5W Minimum 250 Lumen Output	per unit	15.00
YEC0222	ENERGY STAR® Qualified LED Decorative Bulb E12 Candelabra or E26 Base, ≤ 8W Minimum 400 Lumen Output	per unit	15.00
YEC0223	ENERGY STAR® Qualified Globe Lamp, ≤ 6W Minimum 250 Lumen Output	per unit	15.00
YEC0224	ENERGY STAR® Qualified Filament Lamp, ≤ 7W Minimum 250 Lumen Output	per unit	10.00
YEC0225	ENERGY STAR® Qualified Filament Lamp, ≤ 9W Minimum 500 Lumen Output	per unit	10.00
YEC0232	High Bay LED (≤139W),	per unit	425.00
YEC0233	High Bay LED (>139W to ≤175W),	per unit	485.00
YEC0234	1 Lamp LED Tube Re-Lamp, ≤12W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	30.00
YEC0235	2 Lamp LED Tube Re-Lamp, ≤12W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	60.00
YEC0236	3 Lamp LED Tube Re-Lamp, ≤12W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	90.00
YEC0237	4 Lamp LED Tube Re-Lamp, ≤12W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	120.00
YEC0238	1 Lamp LED Tube Re-Lamp, ≤15W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	20.00
YEC0239	2 Lamp LED Tube Re-Lamp, ≤15W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	45.00
YEC0240	3 Lamp LED Tube Re-Lamp, ≤15W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	65.00
YEC0241	4 Lamp LED Tube Re-Lamp, ≤15W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	90.00
YEC0242	1 Lamp LED Tube Re-Lamp, ≤ 22W (Nominal Lamp Wattage) Minimum 2200 Lumen Output Per Lamp	per unit	30.00
YEC0243	2 Lamp LED Tube Re-Lamp, ≤ 22W (Nominal Lamp Wattage) Minimum 2200 Lumen Output Per Lamp	per unit	60.00
YEC0244	3 Lamp LED Tube Re-Lamp, ≤ 22W (Nominal Lamp Wattage) Minimum 2200 Lumen Output Per Lamp	per unit	85.00

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0245	4 Lamp LED Tube Re-Lamp, ≤ 22W (Nominal Lamp Wattage) Minimum 2200 Lumen Output Per Lamp	per unit	85.00
YEC0246	2 Lamp LED Tube Re-Lamp, ≤44W (Nominal Lamp Wattage) Min. 4400 Lumen Output, 8' Length	per unit	100.00
YEC0247	1 Lamp LED Tube Re-Lamp, ≤44W (Nominal Lamp Wattage) Min. 4400 Lumen Output, 8' Length	per unit	50.00
YEC0248	2 Lamp LED Tube Re-Lamp, ≤35W (Nominal Lamp Wattage) Min. 3500 Lumen Output, 8' Length	per unit	100.00
YEC0249	1 Lamp LED Tube Re-Lamp, ≤35W (Nominal Lamp Wattage) Min. 3500 Lumen Output, 8' Length	per unit	50.00
YEC0250	4-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤14W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	90.00
YEC0251	3-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤14W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	100.00
YEC0252	2-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤14W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	80.00
YEC0253	1-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤14W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	55.00
YEC0254	4-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤20W (Nominal Lamp Wattage) Minimum 2000 Lumen Output Per Lamp	per unit	90.00
YEC0255	3-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤20W (Nominal Lamp Wattage) Minimum 2000 Lumen Output Per Lamp	per unit	75.00
YEC0256	2-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤20W (Nominal Lamp Wattage) Minimum 2000 Lumen Output Per Lamp	per unit	60.00
YEC0257	1-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤20W (Nominal Lamp Wattage) Minimum 2000 Lumen Output Per Lamp	per unit	40.00
YEC0258	Outdoor Wall-mounted Area LED fixture (≤30W), ≤30W and ≥400 Lumens	per unit	150.00
YEC0259	Outdoor Wall-mounted Area LED fixtureLED fixture (≤60W), ≤60W and >2,850 Lumens	per unit	300.00
YEC0260	Outdoor Wall-mounted Area LED fixture LED fixture (≤120W), ≤120W and >5,700 Lumens	per unit	375.00
YEC0261	Refrigerated Display Case LED Fixture - Horizontal Installation (Undershelf), <13W, Nominal 24" to 48" LED Fixture	per unit	75.00
YEC0262	Refrigerated Display Case LED Fixture - Vertical Installation, <30W, Nominal 48" to 72" LED fixture	per unit	135.00
YEC0263	LED Exit Sign Retrofit Kit or New Sign, ≤3W	per unit	35.00
YEC0264	Design Lights Consortium Listed 4-Pin LED Replacement Lamp, ≤ 10W Minimum 900 Lumen Output Lamp	per unit	20.00

Measure Code	Measure Name	Unit Definition	Incentive per unit
YEC0265	Design Lights Consortium Listed 4-Pin LED Replacement Lamp, ≤ 10W Minimum 900 Lumen Output Lamp	per unit	20.00
YEC0266	2' x 4' Integral LED Troffer or 4' Linear Ambient Luminaire, ≥6000 Lumen Output	per unit	240.00
YEC0267	2' x 4' Integral LED Troffer or 4' Linear Ambient Luminaire, ≥3000 Lumen Output	per unit	220.00
YEC0268	1' x 4' Integral LED Troffer, 2' x 2' Integral LED Troffer or 4' Linear Ambient Luminaire, ≥1500 Lumen Output	per unit	190.00
YEC0269	8' Linear Ambient Luminaire, ≥4500 Lumen Output	per unit	130.00
YEC0270	8' Linear Ambient Luminaire, ≥9000 Lumen Output	per unit	155.00

Exhibit 66: Measure Level Participation Projections

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0190	Heat Recovery Ventilation	per 100 CFM	4	5	5
YEC0191	Advanced Thermostats	per unit	38	41	39
YEC0192	Strip Curtain Walk-in Cooler	per foot	4	5	5
YEC0193	Strip Curtain Walk-in Freezer	per foot	4	5	5
YEC0194	Night Curtains - Coolers	per foot	4	5	5
YEC0195	LED Case Lighting	per linear ft	4	5	5
YEC0196	LED A19 Lamps - Over 60W	per lamp	45	50	47
YEC0197	LED A19 Lamps - 60W Eqvt. Or lower	per lamp	45	50	47
YEC0198	Door Gaskets - Walk-In Cooler	per linear ft	3	4	4
YEC0199	Door Gaskets - Walk-In Freezer	per linear ft	3	4	4
YEC0200	Door Auto Closers - Walk-In Cooler	per door	4	5	5
YEC0201	Door Auto Closers - Walk-In Freezer	per door	4	5	5
YEC0202	ENERGY STAR® Qualified LED PAR 16 pin or screw base, ≤ 6W Minimum 250 Lumen Output	per unit	113	124	118
YEC0203	ENERGY STAR® Qualified LED MR 16 pin or screw base, ≤ 6W Minimum 250 Lumen Output	per unit	113	124	118
YEC0204	ENERGY STAR® Qualified LED PAR 16 pin or screw base, ≤ 8W Minimum 400 Lumen Output	per unit	18	20	19
YEC0205	ENERGY STAR® Qualified LED MR 16 pin or screw base, ≤ 8W Minimum 400 Lumen Output	per unit	18	20	19
YEC0206	ENERGY STAR® Qualified LED PAR 20, ≤ 7W Minimum 500 Lumen Output	per unit	27	30	29
YEC0207	ENERGY STAR® Qualified LED BR20, ≤ 7W Minimum 500 Lumen Output	per unit	27	30	29
YEC0208	ENERGY STAR® Qualified LED PAR 30, ≤ 12W Minimum 600 Lumen Output	per unit	27	30	29
YEC0209	ENERGY STAR® Qualified LED BR 30, ≤ 12W Minimum 600 Lumen Output	per unit	27	30	29

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0210	ENERGY STAR® Qualified LED PAR 30, ≤ 16W Minimum 800 Lumen Output	per unit	14	15	14
YEC0211	ENERGY STAR® Qualified LED BR 30, ≤ 16W Minimum 800 Lumen Output	per unit	14	15	14
YEC0212	ENERGY STAR® Qualified LED PAR 38, ≤ 12W Minimum 600 Lumen Output	per unit	27	30	29
YEC0213	ENERGY STAR® Qualified LED BR40, ≤ 12W Minimum 600 Lumen Output	per unit	27	30	29
YEC0214	ENERGY STAR® Qualified LED PAR 38, ≤ 14W Minimum 800 Lumen Output	per unit	14	15	14
YEC0215	ENERGY STAR® Qualified LED BR40, ≤ 14W Minimum 800 Lumen Output	per unit	14	15	14
YEC0216	ENERGY STAR® Qualified LED PAR 38, ≤ 19W Minimum 1100 Lumen Output	per unit	14	15	14
YEC0217	ENERGY STAR® Qualified LED BR40, ≤ 19W Minimum 1100 Lumen Output	per unit	14	15	14
YEC0218	ENERGY STAR® Qualified LED A Shape, ≤ 9W Minimum 450 Lumen Output	per unit	135	149	141
YEC0219	ENERGY STAR® Qualified LED A Shape, ≤ 11W Minimum 800 Lumen Output	per unit	135	149	141
YEC0220	ENERGY STAR® Qualified LED A Shape, ≤ 16W Minimum 1200 Lumen Output	per unit	90	99	94
YEC0221	ENERGY STAR® Qualified LED Decorative Bulb E12 Candelabra or E26 Base, ≤ 5W Minimum 250 Lumen Output	per unit	23	25	23
YEC0222	ENERGY STAR® Qualified LED Decorative Bulb E12 Candelabra or E26 Base, ≤ 8W Minimum 400 Lumen Output	per unit	23	25	23
YEC0223	ENERGY STAR® Qualified Globe Lamp, ≤ 6W Minimum 250 Lumen Output	per unit	9	10	9
YEC0224	ENERGY STAR® Qualified Filament Lamp, ≤ 7W Minimum 250 Lumen Output	per unit	9	10	9
YEC0225	ENERGY STAR® Qualified Filament Lamp, ≤ 9W Minimum 500 Lumen Output	per unit	9	10	9
YEC0232	High Bay LED (≤139W),	per unit	45	50	47
YEC0233	High Bay LED (>139W to ≤175W),	per unit	45	50	47
YEC0234	1 Lamp LED Tube Re-Lamp, ≤12W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	75	83	79
YEC0235	2 Lamp LED Tube Re-Lamp, ≤12W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	45	50	47
YEC0236	3 Lamp LED Tube Re-Lamp, ≤12W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	23	25	23
YEC0237	4 Lamp LED Tube Re-Lamp, ≤12W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	11	13	12
YEC0238	1 Lamp LED Tube Re-Lamp, ≤15W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	19	21	20

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0239	2 Lamp LED Tube Re-Lamp, ≤15W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	18	20	19
YEC0240	3 Lamp LED Tube Re-Lamp, ≤15W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	8	9	8
YEC0241	4 Lamp LED Tube Re-Lamp, ≤15W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	30	34	32
YEC0242	1 Lamp LED Tube Re-Lamp, ≤ 22W (Nominal Lamp Wattage) Minimum 2200 Lumen Output Per Lamp	per unit	19	21	20
YEC0243	2 Lamp LED Tube Re-Lamp, ≤ 22W (Nominal Lamp Wattage) Minimum 2200 Lumen Output Per Lamp	per unit	18	20	19
YEC0244	3 Lamp LED Tube Re-Lamp, ≤ 22W (Nominal Lamp Wattage) Minimum 2200 Lumen Output Per Lamp	per unit	8	9	8
YEC0245	4 Lamp LED Tube Re-Lamp, ≤ 22W (Nominal Lamp Wattage) Minimum 2200 Lumen Output Per Lamp	per unit	26	28	28
YEC0246	2 Lamp LED Tube Re-Lamp, ≤44W (Nominal Lamp Wattage) Min. 4400 Lumen Output, 8' Length	per unit	11	13	13
YEC0247	1 Lamp LED Tube Re-Lamp, ≤44W (Nominal Lamp Wattage) Min. 4400 Lumen Output, 8' Length	per unit	11	13	13
YEC0248	2 Lamp LED Tube Re-Lamp, ≤35W (Nominal Lamp Wattage) Min. 3500 Lumen Output, 8' Length	per unit	8	9	8
YEC0249	1 Lamp LED Tube Re-Lamp, ≤35W (Nominal Lamp Wattage) Min. 3500 Lumen Output, 8' Length	per unit	18	20	19
YEC0250	4-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤14W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	19	21	20
YEC0251	3-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤14W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	19	21	20
YEC0252	2-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤14W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	19	21	20
YEC0253	1-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤14W (Nominal Lamp Wattage) Minimum 1500 Lumen Output Per Lamp	per unit	19	21	20
YEC0254	4-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤20W (Nominal Lamp Wattage) Minimum 2000 Lumen Output Per Lamp	per unit	23	25	23
YEC0255	3-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤20W (Nominal Lamp Wattage) Minimum 2000 Lumen Output Per Lamp	per unit	23	25	23
YEC0256	2-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤20W (Nominal Lamp Wattage) Minimum 2000 Lumen Output Per Lamp	per unit	23	25	23
YEC0257	1-Lamp Double-Ended UL Type B LED Tube Retrofit, ≤20W (Nominal Lamp Wattage) Minimum 2000 Lumen Output Per Lamp	per unit	23	25	23

Measure Code	Measure Name	Unit Definition	Y1	Y2	Y3
YEC0258	Outdoor Wall-mounted Area LED fixture (≤30W), ≤30W and ≥400 Lumens	per unit	15	17	16
YEC0259	Outdoor Wall-mounted Area LED fixtureLED fixture (≤60W), ≤60W and >2,850 Lumens	per unit	16	17	17
YEC0260	Outdoor Wall-mounted Area LED fixture LED fixture (≤120W), ≤120W and >5,700 Lumens	per unit	10	11	10
YEC0261	Refrigerated Display Case LED Fixture - Horizontal Installation (Undershelf), <13W, Nominal 24" to 48" LED Fixture	per unit	9	10	9
YEC0262	Refrigerated Display Case LED Fixture - Vertical Installation, <30W, Nominal 48" to 72" LED fixture	per unit	9	10	9
YEC0263	LED Exit Sign Retrofit Kit or New Sign, ≤3W	per unit	8	9	8
YEC0264	Design Lights Consortium Listed 4-Pin LED Replacement Lamp, ≤ 10W Minimum 900 Lumen Output Lamp	per unit	9	10	9
YEC0265	Design Lights Consortium Listed 4-Pin LED Replacement Lamp, ≤ 10W Minimum 900 Lumen Output Lamp	per unit	9	10	9
YEC0266	2' x 4' Integral LED Troffer or 4' Linear Ambient Luminaire, ≥6000 Lumen Output	per unit	92	101	95
YEC0267	2' x 4' Integral LED Troffer or 4' Linear Ambient Luminaire, ≥3000 Lumen Output	per unit	92	101	95
YEC0268	1' x 4' Integral LED Troffer, 2' x 2' Integral LED Troffer or 4' Linear Ambient Luminaire, ≥1500 Lumen Output	per unit	144	158	150
YEC0269	8' Linear Ambient Luminaire, ≥4500 Lumen Output	per unit	9	10	9
YEC0270	8' Linear Ambient Luminaire, ≥9000 Lumen Output	per unit	9	10	9

2.3 Super-Insulated New Buildings

Non-Dispatchable Capacity & Energy Savings

2.3.1 Program Description

The proposed Program is a commercial new construction program, a common type of DSM program. The Program will offer incentives for building commercial buildings with superior energy performance.

Building owners/managers will receive an incentive for electricity-efficient new building construction. YEC will offer an incentive only if the building is to heat space and water with electricity in full.

Duplication would need to be avoided between the proposed Super-Insulated New Buildings and the Energy Branch's Good Energy Program. Only renewable energy generating systems or renewable heating system upgrades are eligible for new commercial buildings in the Good Energy Program, and these measures are excluded from this proposed program. The Energy Branch offers a similar program for new homes, called ZeroPath rebate, and while this is currently only available to new residential buildings, the Energy Branch may wish to expand the ZeroPath program to commercial buildings.

The incentive will have two paths:

Prescriptive Path. Prescriptive incentives will be determined using a dollar per square foot rate if the building complies with a certain standard. The standard will be designed to be slightly more stringent than the Model National Energy Building code minus 25% (MNEBC -25%) and the City of Whitehorse's Building and Plumbing Bylaw. Typical focus areas include: building systems, insulation, and infiltration. Savings will be determined via a deemed savings approach. Project incentive amounts will be capped at 30% of the eligible project costs.

Custom Path. Custom incentives will be determined using a dollar per kilowatt-hour of annual savings rate for each kilowatt-hour of savings that are realized above the modeled base case energy savings (greater than 25%). Savings will be determined via building energy modelling. The modelling requirements will be the same as for the Canadian Green Building Council's LEED building certification. Participation in the custom incentive track will be set up to be in lockstep with LEED building certification to minimize transaction cost for the participants. Project incentive amounts will be capped at 30% of the eligible project costs.

Compliance for the prescriptive path can be proved through two approaches. The first is by a list of prescriptive requirements, similar to but superior to the City of Whitehorse's Building and Plumbing Bylaw. The second is by meeting a minimum performance threshold when using the NRCan EE4 Screening Tool.

The participation process will first require a pre-approval step in order to check eligibility criteria and estimate the incentive amount for a single building or set of buildings. The construction work will not start before the project is pre-approved. Once pre-approval is received, construction can begin. After completion of the installation work, the participant will submit a completion form and provide backup documentation, this may include building permit documentation, the as-built project documentation, as-built building energy model, supporting model documentation and energy modelling report to receive their incentive payment. Incentives will be fulfilled to participating building owners/managers.

YEC will disseminate information, train and receive feedback from building owners/managers, the building industry actors through multiple means. To promote Program uptake, YEC will focus primarily with the architectural and engineering firms, local construction contractors and property managers; and then from the local construction contractors to the developers and their clients. YEC will also use these interactions to cross-promote other relevant program offerings, such as demand management programs and pilots.

The program should not encourage electric heating over other sources of energy. The assumption is that the incentive level will be substantial enough to justify increasing the performance of the building, but not be substantial enough to justify using electricity for space and water heating rather than thermal sources of energy.

2.3.2 Target Market

The primary target market is new commercial buildings in the Yukon Integrated System. Participants must be general service, non-residential customers.

2.3.3 Approach to Implementation

YEC will collaborate with the Whitehorse Chamber of Commerce and the Yukon Contractor Association to gain access to architects, engineers, builders and building portfolio managers.

2.3.4 Eligible Technologies and Measures

The proposed initial measures, incentive levels, and projected participation levels are presented below:

Exhibit 67: Initial Measures List with Incentive Levels and Participation Projections

Measure Code	Measure Name	Unit Definition	Incentive per unit	Y1	Y2	Y3
YEC0271	Whole Building Design – 25% Better than Current Practice	per Sq.ft	$1.00	-	60,000	60,000
YEC0272	Whole Building Design – 40% Better than Current Practice	per Sq.ft	$2.00	-	40,000	40,000

2.4 Street Lighting Upgrade

Non-Dispatchable Capacity & Energy Savings

2.4.1 Program Description

YEC proposes that all mercury vapor and high-pressure sodium street lights in Yukon be replaced by new LED fixtures. YEC is already proceeding with retrofitting its own assets to LED. We propose that ATCO do the same. As demonstrated through the cost-effectiveness tests results, there is a business case for ratepayers to fund the retrofitting of all public street lamps in short order. The business case is attractive because public lighting load is a direct contributor to the system peak. The program is a street light retrofit Project across all of ATCO service territory and will replace the small number of YEC's remaining HPS street lights. It is proposed that ATCO would act as a contractor under a contract with YEC. YEC would cover 100% of the cost and get cost recovery through its rate along with other DSM expenditures.

Ratepayer money would be used to retrofit ATCO's equipment to both reduce the overall electricity consumption in Yukon and the winter peak, which would lead to an overall reduction in revenue requirements and thereby electricity bills.

Furthermore, ATCO may consider redesigning its street lighting rate structures (municipal, energy only, and private) to move away from a demand charge (cents per watt) toward a charge based on the light output of the fixtures ($ per lumens, or $ for given LED fixture model), or an "HPS wattage equivalent". ICF recommends the Yukon Utilities Board consider compensating ATCO for its foregone earnings to ensure ATCO is also a winning party in this Project.

There is no duplication between Street Lighting Upgrade and the Good Energy Program. The Energy Branch does not offer incentives for street lights.

2.4.2 Target Market

All public lighting (mercury vapor and high-pressure sodium fixtures) owned by ATCO and within the Yukon Integrated System would be retrofitted and converted to LED fixtures as a 3-year Project.

2.4.3 Approach to Implementation

ATCO would complete the detailed design of the Project. ATCO would tender the work to local contractors and suppliers.

2.4.4 Eligible Technologies and Measures

The proposed initial measures, incentive levels, and projected participation levels are presented below:

Exhibit 68: Initial Measures List with Incentive Levels and Participation Projections

Measure Code	Measure Name	Unit Definition	Total Incentive Level (per unit)	Y1	Y2
YEC0275	LED Street Light - 70W HPS – 25W LED	per light head	$362.00	60	60
YEC0276	LED Street Light - 100W HPS – 41W LED	per light head	$420.00	1,661	1,660
YEC0277	LED Street Light - 150W HPS – 88W LED	per light head	$577.00	263	263
YEC0278	LED Street Light - 150W HPS decorative (mainstreet and Whistle Bend) – 72W LED	per light head	$686.50	38	38
YEC0279	LED Street Light - 250W HPS – 161W LED	per light head	$734.50	651	651
YEC0280	LED Street Light <= 400W HPS – 250W LED	per light head	$1015.00	84	84

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ATTACHMENT 5.2A-2.2
YUKON DSM PROGRAM COMPARISON

Appendix 1 – Yukon DSM Program Comparison

Report By: Eric Labrecque (Yukon Energy Demand-Side Management EIT)

Demand-side management (DSM) programs are defined in OIC 2021-16, Section 10(1) as “a measure, action, or program intended to promote customer use of electricity that optimizes economy or efficiency of electricity generation or transmission by a public utility, including through the promotion of customer use of electricity that (1) is more efficient, or (2) better aligns electricity supply and demand.”

Regarding DSM program duplication, OIC 2021-16 stipulates in Section 10(3) that there must not be any “duplication between (a YEC DSM program) for which costs are incurred and a DSM program provided by the Government of Yukon or in which the Government of Yukon is a participant.” Demonstrating that there is no such duplication is the purpose of this report. All DSM programs currently operated by four entities will be identified and compared: Yukon Energy Corporation (YEC), the Yukon Government’s Energy Branch and Department of Highway & Public Works, Yukon Housing Corporation, and ATCO Electric Yukon. These entities have been identified by Yukon Energy as being relevant to OIC 2021-16 Section 10(3), as either a public utility or Government of Yukon department or crown corporation that may be running or participating in DSM program(s).

DSM programs will be identified by sector, including residential, commercial/institutional and transportation, and further identified by type – capital incentives, like rebates, coupons, and other one-time incentives to offset capital costs, and on-going incentives, like on-bill credits or other recurring incentives.

Table 1, on the following page, contains a full listing of all programs considered relevant to OIC 2021-16’s definition of “demand-side management program” from the relevant entities. Programs listed are current programs, or programs planned for launch in 2023, as of May 1, 2023. Program listings are confirmed as accurate and complete by each entity on the signatory page that follows.

Table 1: DSM Program Listing

Entity: ***DSM Program Area***	**Yukon Energy**	**YG Energy Branch**	**YG Highways & Public Works (HPW)**	**Yukon Housing Corporation (YHC)**	**ATCO Electric Yukon (ATCO)**
Residential Buildings					
Capital Incentives:	Smart thermostats Hot water tank controllers	Rebates for various energy-saving technologies and upgrades, excluding smart thermostats and hot water tank controllers. Rebates for highly efficient new homes.	HPW has no demand-response programs for residential buildings, and no such programs are anticipated in the future.	YHC does not participate in or provide any demand response programs other than Yukon Energy's. Development of or participation in any demand response programs by YHC would be conducted in coordination with Yukon Energy to prevent program duplication.	ATCO currently has no demand-response programs. No incentives, either capital or on-going, are available from ATCO on smart thermostats or hot water tank controllers. Any new DSM programs by ATCO would be developed in coordination with Yukon Energy to prevent program duplication.
On-Going Incentives:	Current: None Planned: On-bill credits for smart thermostat and hot water tank controller demand response program participants (2024/25)	Micro-Generation Program			
Commercial / Institutional					
Capital Incentives:	None.	Funding for various energy saving technologies and upgrades, including smart thermostats and electric vehicle chargers.	HPW does not participate in or provide demand-response programs or incentives. Rather, HPW delivers capital projects from an asset management and greenhouse gas reduction standpoint.	See comments above.	See comments above.
On-Going Incentives:	Independent Power Producer Program Planned: On-bill credits as an on-going incentive for participants in our commercial/ institutional demand response program, permitting pre-approved utility control of specific loads and/or on-site generation during demand response events (~2025/26)	Independent Power Producer Program Micro-Generation Program	HPW does not provide on-going incentives for any DSM programs.	See comments above.	See comments above.
Transportation					
Capital Incentives:	None.	Rebates and other funding for motorized and non-motorized electric vehicles and vehicle charging systems.	HPW does not provide any incentives, either capital or on-going, for any DSM programs.	See comments above.	See comments above.
On-Going Incentives:	Current: None. Planned: On-bill credits for demand response program participants with compatible EV chargers (~2025)	None.			

By signing below, each party agrees that the DSM programs associated with their organization listed in Table 1: DSM Program Listing of this document is an accurate and complete listing of the DSM programs their organization is participating in and/or running. Signing below does not imply agreement with contents of any other section this report or any document this report is appended to.

Yukon Government – Energy Branch

In lieu of a signature here, the Yukon Government Energy Branch has provided the attached letter of support, confirming there is no DSM program duplication and demonstrating full support of Yukon Energy's DSM Programs.

Yukon Government – Highways & Public Works

Signatory Name: Anett Kralisch

Signatory Position: A/Director, Business Transformation

Signature:

Date: 2023/07/12

Yukon Energy Corporation

Signatory Name: Michael Muller

Signatory Position: Vice President

Signature:

Date: August 18, 2023

Yukon Housing Corporation

Signatory Name: Eric Gaucher

Signatory Position: Acting Director

Signature:

Date: 2023/06/20

ATCO Electric Yukon

Signatory Name: Tony Badry

Signatory Position: Manager

Signature:

Yukon

Energy Branch, Department of Energy, Mines and Resources
PO Box 2703, Whitehorse, Yukon Y1A 2C6
June 20, 2023

Yukon Energy Corporation
2 Miles Canyon Rd., Whitehorse, Yukon Y1A 6S7

Yukon Energy Corporation,

The Energy Branch expresses our full support for Yukon Energy Corporation's proposed demand-side management programs related to smart thermostats and hot water tank controllers. The proposed programs do not duplicate or overlap with any of the Energy Branch's current or planned programs and incentives.

Our energy efficiency programs complement and support YEC's planned demand management programs and we are supportive of the proposed programs moving forward. We understand the need for innovative demand management programs to maximize the impact of electrification and energy efficiency initiatives.

Collaboration between government and utilities is essential to achieving our shared goals of affordable, reliable, and renewable electricity for Yukoners. The Energy Branch is prepared to support YEC's demand management programs through engagement, shared data, and ongoing collaborations that facilitate cooperatively achieving our climate commitments.

Sincerely,

Shane Andre
Director, Energy Branch, Energy, Mines and Resources
Government of Yukon

APPENDIX 5.2B
DEFERRED STUDIES >$100,000 AND <$1 MILLION ADDED TO RATE BASE

APPENDIX 5.2B: DEFERRED STUDIES >$100,000 AND <$1 MILLION ADDED TO RATE BASE

Appendix 5.2B summarizes deferred cost projects over $100,000 but less than $1 million that will be added to rate base in the test years. Details on project costs are summarized in Tables 5.3 to 5.6.

Rate base additions from 2021 to 2024 in each deferred cost activity totalling between $100,000 and $1 million that impact 2024 rate base are summarized below (total rate base impact in 2024 test year of approximately $3.716 million, excluding reductions due to amortization, reflecting $0.581 million additions in 2021, $0.115 million additions in 2022, $1.692 million additions in 2023, and $1.328 million additions in 2024).

- **Feasibility Studies – Reliability & Asset Improvements**. Rate base additions of approximately $2.229 million for the following projects:
  - Whitehorse Post-Flood Assessment ($0.115 million in 2022);
  - Mayo Civil Infrastructure Refurbishment Planning ($0.168 million in 2023);
  - System Wide Arc Flash Study ($0.198 million in 2023);
  - System Wide Stability Study ($0.200 million in 2023);
  - Digital Strategy and Policy Development ($0.120 million in 2023);
  - Privacy Management Program ($0.100 million in 2023);
  - Cyber Security Framework ($0.140 million in 2024);
  - WRGS Thermal Assessment & Permitting ($0.413 million in 2024);
  - Transmission Line Detailed Inspection Program ($0.250 million in 2024);
  - Gates/TIVs Certification Assessment System Wide ($0.200 million in 2024);
  - Digital Reporting Review ($0.125 million in 2024);
  - Records Policy Planning and Program Development ($0.100 million in 2024); and
  - Breaker Condition Assessment ($0.100 million in 2024).
- **Regulatory and Dam Safety Review**: Rate base additions of approximately $1.486 million for the following projects:
  - Dam Safety Review ($0.255 million in 2021);

- IPP Standing Offer Implementation ($0.326 million in 2021, $0.070 million in 2023);
- Atlin EPA Section 18 Proceeding (Hearing Reserve Account) ($0.386 million in 2023);
- Public Safety Plans ($0.225 million in 2023); and
- Vegetation Management Plan Update ($0.225 million in 2023).

5.2B-2: FEASIBILITY STUDIES – RELIABILITY & ASSET IMPROVEMENTS

Whitehorse Post-Flood Assessment	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
		$0.115 million		

2021 saw an unprecedented amount of water flow through the Whitehorse dam spillway and hydro units with maximum combined flow of over 730 cms. The flow over the spillway was around 500 to 540 cms for about two months. A typical year sees the spillway flow peak around 200 to 230 cms and is not a long term sustained flow. Unknown issues may have arisen from this sustained flow, such as toe scour, plunge pool erosion, and/or concrete cracking.

This project involved an underwater sonar scan of the toe of the spillway and plunge pool to determine if any significant damage occurred during the high water event. Although no major issues were identified, the scan highlighted areas for future monitoring and will provide a baseline condition for assessment following any future flooding events.

Mayo Civil Infrastructure Refurbishment Planning	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
			$0.168 million	

There are many civil/structural issues in and around the Mayo Generating Station including various roads, the intake structure, Wareham Dam spillway & gates, and the Mayo Lake control structure. Some structures are having issues that could be repaired (intake structure, wood planking at Mayo Lake) and some are potentially at end of life (spillway and spill gates).

This project was completed in 2022 and involved hiring an engineering firm (Stantec) to perform an on-site assessment of the structures and develop a recommended multi-year capital plan (including high-level cost estimates) to address the areas of concerns.

System Wide Arc Flash Study	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.198 million	

A system wide Arc Flash Hazard Assessment is required every five years or whenever there are major additions or significant changes in the system as per CSA Z462. The most recent Arc Flash Hazard Assessment was conducted in 2016/2017 and since that time there have been major or planned additions to the system (Victoria Gold, BESS, STATCOM and IPPs).

The assessment will specify electrical safety requirements to protect workers around energized electrical equipment during installation, inspection, use, and maintenance.

System Wide Stability Study	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.200 million	

The Yukon electrical grid is a radial system with a ~500 km long 138 kV transmission line from Whitehorse to Stewart Crossing and 180 km and 55 km 69 kV transmission lines from Stewart Crossing to Dawson and Mayo respectively. The 138 kV side of the system has several separation points; any transmission trip results in high and low frequencies in different parts of the system. The reactive power shift is significant due to high line charging currents (long, lightly loaded transmission lines) resulting in high and low voltages in different parts of the system. Stability of the system is key to ensure reliability and reduce outages.

In 2017, as part of the Eagle Gold system study (which included a stability study), several solutions were proposed to improve system stability and ensure large power flow from south to north. The Underfrequency Loadshedding Scheme (UFLS) was revamped and a Remedial Action Scheme (RAS) was added to the Whitehorse and Mayo areas to ensure minimal loss and quick restoration during the worst system events.

Since the 2017 Eagle system study, the following significant changes to the Yukon Integrated System have resulted in the need for an updated study: addition of the STATCOM at the Stewart South substation (a recommendation from the 2017 study), upcoming 20MW/40MWh BESS, planned addition of renewable energy generation (wind and solar), and the upcoming Atlin Hydro project.

These major additions would change how the system is operated and protected.

The system wide stability study would inform YEC on the expected behavior of the system with these additions and provide recommendations on how to maintain/improve system stability. The integration of a BESS is a key focus as it will drive how the UFLS and RAS are coordinated and adjusted, the number of renewables the system can accommodate without compromising system reliability, and the tuning of the hydro governors. The stability study will also provide an optimal setting for the STATCOM to maintain voltage levels and optimize the use of reactors at various substations.

Digital Strategy and Policy Development	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.120 million	

As Yukon Energy's use of technology has grown over the years, the related governance model and internal policies have not kept pace. This has resulted in a lack of guidelines, clear ownership of certain systems, and overarching vision that guides the inevitable reliance on digital communication, storage, and integration with various business practices. Recently, this gap in policy has been highlighted by information requests from the Auditor General, who performs the annual financial statement audit of YEC.

This project will leverage the expertise of an external consultant to develop a governance model, strategy, and related polices that align with industry best practices and allow YEC to efficiently embrace continued growth in the use of technology. YEC has signed a contract with Gartner to lead this project and also formed a Digital Governance Committee. Due to personnel changes in key positions related to this work, project initiation delays have occurred and it is likely that this project will extend into 2024.

Privacy Management Program	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.100 million	

As directed by Yukon's Ombudsman under the *Access to Information dn Privacy Act (ATIPP),* the Corporation needs to establish a formal Privacy Management Program compliant with Yukon laws.

This project involves hiring an external consultant to develop a program, materials, and related policies that comply with the relevant legislation.

Cyber Security Framework	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
				$0.140 million

The existing cyber security reporting metrics are no longer relevant and do not allow for proper oversight and governance.

This project will use an external consultant to assist in the development of a cyber security framework and related policies that align with industry best practices. If this project is not complete, YEC will not be able to properly assess the ongoing risk of a cyber incident.

WRGS Thermal Assessment & Permitting	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
				$0.413 million

The purpose of the project is to identify the maximum thermal generating capacity at the Whitehorse Rapids Generating Station (WRGS) that would be permissible under pending regulatory thresholds and obtain the necessary operating authorizations. The thermal generation at WRGS will contribute to meeting the forecast demand on the Yukon Integrated System (YIS) in combination with other generating resources of the territory during extreme low temperatures and emergencies.

YEC's thermal generation capacity is regulated through an Air Emissions Permit from Yukon Government. The air quality regulatory thresholds are expected to become increasingly stringent over the next few years and influence decisions on where and how YEC can operate thermal generation. Air quality modelling is showing that the amount of thermal capacity YEC would like to operate at WRGS will not meet these new criteria. As a result, exploring thermal generation scenarios that are practical, cost-effective, and permittable has become critically important. This project will consider thermal capacity requirements at the WRGS and other corporate sites to meet regulatory thresholds (e.g., air emissions).

YEC will only focus in this project on the assessment and permitting aspects for the WRGS. Relicensing is to occur prior to expiry of the current Air Emissions Permit on December 31, 2024, with the assessment being completed by early 2024.

Transmission Line Detailed Inspection Program	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
				$0.250 million

YEC operates approximately 5,000 transmission structures consisting of more than 10,000 wood poles. The structure's equipment and poles require inspection on a regular cycle in order to detect failing or deteriorated equipment before it fails in service. Overhead line detailed inspection cycles are typically planned for transmission lines 15 years after initial construction and every 10 years thereafter.

This project involves hiring a qualified contractor to complete inspection and issue a report that will support a data driven capital maintenance program.

Detailed inspection and test and treat programs have been defined as part of YEC's strategy for collecting the necessary condition data for managing wood pole transmission line assets. An inspection cycle will typically identify several years of justifiable, condition-based repair and refurbishment work, which is necessary to keep the line in a state of good repair. Detailed inspection is necessary to develop condition-based action plans for YEC's Transmission lines. Detailed inspection of field assets is required to:

- Gather data to trend deterioration. This data, when compared to historic records, facilitates improved forecasting of future work in future.
- Identify priority repair or replacement work based on the actual condition of the equipment in the field. This

information forms the basis for repair/replacement programs to be funded in the immediate and near future.

Both inspection and test and treat are normal utility practice to gather data for the proactive management of transmission line assets, to avoid in-service failure due to the presence of unknown defects. Without a clear understanding of actual structure condition and repair requirements, it is impossible to identify, repair, or replace poor condition hardware proactively.

In-service failure can have serious consequences including transmission and customer outage and corresponding thermal run, public safety issues, potential for forest fire, and unplanned emergency restoration work. This unplanned work typically occurs under adverse conditions, is more costly, and carries additional safety risks over controlled, planned maintenance and repair work.

Without actual equipment condition data to develop a planned, proactive repair program, YEC is forced to perform reactive repairs after equipment fails. This will adversely impact YEC's ability to achieve objectives of cost effectiveness, safety, and reliability. Because of the risks outlined (cost, safety, reliability), reactive management of transmission assets is not a desirable situation.

Detailed inspections planned for 2024 include transmission lines L177 (Stewart Crossing to Dawson) and L176 (Stewart Crossing to Mayo). Both of these lines were constructed in 2003 and are beyond the 15-year recommended timeline for an initial inspection.

Gates/TIVs Certification Assessment System Wide	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
				$0.200 million

Throughout the system, YEC has a number of hydro intake gates, tailrace gates, spillway gates, bulkheads, stoplogs, turbine inlet valves, and hydro related Single Device Isolation (SDI) points. These must be inspected and certified to ensure that planned and emergency work can proceed safely when required.

SDI certification is driven by Safe Work Procedure and Regulatory requirements, production requirements, and an obligation to public safety. This equipment is highly critical, and certified equipment in good working condition is required to support production, maintenance, capital work and public safety. SDI recertification is required on a 5-year cycle. Certification on many of the legacy in-service devices has lapsed and requires specialized engineering inspection by a qualified third party to certify. Once initial engineering certification has been established, YEC engineering may in some cases re-certify the device internally.

This project is the first of a three-year program starting in 2024 to perform initial certification of this equipment at an estimated cost of $200K per year. The outcome of the initial certification and inspection program will establish the ongoing re-certification program and will drive additional capital work (as separate projects) where equipment inspection and testing deems it to be at end of life or where major refurbishment is required for certification. The scheduling of inspections will be coordinated with planned outages for O&M and Capital such as overhauls and planned dewatering of penstocks.

Digital Reporting Review	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
				$0.125 million

YEC has many tailor-made reports that have been pieced together throughout the years. Some of these are generated by outdated systems that need upgrades and others are running on older technology that is no longer supported.

This project will document all key reports, create a roadmap for future support and maintenance of these critical tools, and assess the potential to consolidate some of the technologies currently used.

Records Policy Planning and Program Development	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
				$0.100 million

In 2019, YEC commissioned a consultant to complete an Electronic Data Management System study to assess the current state of digital and physical records storage. The study recommended an overarching information management policy developed for the corporation and approved by all stakeholders that is short enough that staff can easily understand the requirements. Coupled with this would be a longer procedure document that goes into more detail that staff could read and be trained on separately.

This project will establish this program including policies and procedures, as well as set long-term visions and direction for YEC document management.

Breaker Condition Assessment	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
				$0.100 million

This is a study to assess the remaining life of YEC breakers in substations from 138kV to 4.16kV including unit breakers and indoor and outdoor switchgear in generating stations. By not gathering this critical information, YEC will be exposed to a higher risk of costly reactive maintenance and significant outages if a breaker fails unexpectedly.

The study results will inform a near term maintenance plan along with a 20-year capital replacement plan including cost estimates.

5.2B-3: REGULATORY AND DAM SAFETY REVIEW

Dam Safety Review	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
	$0.255 million			

Yukon Energy's water use licences require a full dam safety review (DSR) to be performed every 5 years by an external consultant as recommended by the Canadian Dam Association (CDA). Reporting on outcomes of this review is required by each Yukon Energy generating facility water use licence.

Analysis and Conclusions

The DSR includes a comprehensive review of all of Yukon Energy's dam structures, and includes consideration of all civil, structural, geotechnical, electrical, mechanical and safety issues that may affect YEC personnel and the general public. The review identifies hazards and potential problems of high risk that require immediate attention (within one year) as well as lower risk items that can be performed over time. A DSR was completed in 2020 and included an extensive inspection of all water control facilities, underwater inspection of structural elements by divers, geotechnical investigation of the Whitehorse power canal, and research into historical records of YEC assets.

This project was reviewed as part of the 2021 GRA (see YUB-YEC-1-74) which notes a competitive RFP process was initiated. Eight proposals were received, evaluated and awarded based on total score based on best overall proposal which included evaluating technical ability and price. Ecora Engineering was selected as the successful proponent.

The response to YUB-YEC-2-17 updated project costs in 2021 from $0.315 million in the application to $0.253 million. In Order 2022-03 the Board noted that it reviewed the business cases and costs for projects in this category and aside from specifically reference projects (which did not include Dam safety Review) found the actual capital spending to be prudent.

IPP Standing Offer Implementation	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
	$0.326 million		$0.070 million	

Yukon Energy and ATCO Electric Yukon (AEY) are responsible for implementing the Yukon Government's Independent Power Producers (IPP) Policy. The Standing Offer Program (SOP) was developed based on the model used in British Columbia and required development of the following key documents: (1) SOP Program Guide; (2) SOP Program Rules); (3) SOP Application Process; (4) SOP Application Form; (5) Interconnection Standards; and (6) Electricity Purchase Agreement Template.

The utilities were directed to implement the policy by the Yukon Government and are required to execute the policy. OIC 2019-25 requires that utility costs be recovered in rates. Yukon Energy costs related to its share of legal costs for implementation of the IPP policy.

This project was reviewed during the 2021 GRA. Updated costs of $0.330 million were provided in the response to

YUB-YEC-2-17. Other supporting information, including a breakdown of costs, was provided in YUB-YEC-1-95, UCG-YEC-1-49, and UCG-YEC-1-50. In Order 2022-03 the Board noted that it reviewed the business cases and costs for projects in this category and aside from specifically reference projects (which did not include IPP Standing Offer Implementation) found the actual capital spending to be prudent.

Costs of $70k added to ratebase in 2023 relate to a study completed by Hatch to assess the usage of BESS to support renewable integration and minimize the impact of power variability on the grid.

Atlin EPA Section 18 Proceeding (Hearing Reserve Account)	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.386	

This spending addresses the costs of preparing and filing the Atlin EPA Section 18 Review, as well as a full regulatory review. Hearing costs were subject to a Board review as part of the Board's cost awards process following the issuance of the Board's Report and Recommendations.

Public Safety Plans	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.225	

The Canadian Dam Association guidelines for public safety around dams states that the dam owner is responsible for managing risks around the dams that they own, as far upstream and downstream as the property limits extend. As part of the 2020 Dam Safety Review (DSR), it was identified that YEC does not have public safety plans for any of existing the dam facilities. This deficiency was flagged as a high priority task to be completed before the end of 2023.

This project involves hiring an external consultant to develop public safety plans for water control structures located near our generating stations at Whitehorse, Aishihik, and Mayo. Public safety plans will formally document the hazards to the public surrounding our dams and identify the mitigation requirements for reducing the risks of accidents or incidents to members of the public.

Vegetation Management Plan Update	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.225	

A Transmission Vegetation Management Plan (TVMP) is the "road map" for vegetation management and provides direction on how to manage Right-of-Way vegetation in a cost-effective way. It details how the work will be determined, planned, and executed and provides a framework on how vegetation management will be implemented to ensure the reliability of the system.

This project is an update and renewal to the vegetation plan that was completed 10 years ago, with the addition of fall in risk trees which exist outside of regularly brushed section of the right of way. The scope of work for this project includes an inventory of all YEC transmission lines, development of a 10-year management plan for vegetation re-growth and fall in risk, cost estimates for 10-year plans, and a monitoring methodology to ensure the effectiveness of the plans.

APPENDIX 5.3A
INTANGIBLE ASSETS >$1 MILLION ADDED TO RATE BASE

APPENDIX 5.3A: INTANGIBLE ASSETS >$1 MILLION ADDED TO RATE BASE

Appendix 5.3A summarizes intangible assets over $1 million that will be added to rate base in the test years.

An intangible asset is a non-monetary asset without physical substance and that is identifiable (either being separable or arising from contractual or other legal rights). It is a resource that is controlled by an entity as a result of past events (for example, purchase or self-creation) and from which future economic benefits (inflows of cash or other assets) are expected. Examples include patented technology, computer software, databases and trade secrets.

Test year spending on Intangible Assets over $1 million relate to the development and implementation of updated and modernized Asset Management (AM) systems for YEC. For the purpose of this GRA this includes YEC's investment in two distinct, but closely related AM projects:

- the Physical Asset Management Managed System (PAMMS) Asset Management Framework; and
- the Enterprise Management System (EAM) Purchase and Implementation.

The EAM Purchase & Implementation project is an enterprise-level software application that YEC sought to bring into rate base in 2021. It enables YEC, as a key part of its AM program, to manage and optimize -- using a modernized and standard industry technology related software application -- its assets throughout the entire asset lifecycle including asset needs identification, asset investment planning and prioritization, advanced asset maintenance management and asset performance tracking.

In GRA 2021, the YUB disallowed YEC's costs on the EAM based on concerns about the adequacy of the evidence presented by YEC in that application to support it (Board Order 2022-03, Appendix A, paras 332-333). Given the importance and the essential need for the EAM and related AM activities YEC has taken the necessary steps in its present 2023 GRA application to address the concerns identified by the YUB so that previously disallowed expenditures can now be properly included in rate base.

An equally important part of YEC's update to its Asset Management program is a multi-year project started in 2018 which involves the formal documentation of all governance, roles and responsibilities, processes, and procedures required for the establishment and ongoing operation of YEC's asset management system. This project is identified in this application as PAMMS and is being brought into rate base in 2023.

As summarized in Tables 5.2 to 5.5, total forecast spending included in rate base by the end of 2023 for both of these interrelated AM projects is approximately $10.006 million. Overall information and business case assessment for these two interrelated AM projects is provided below – additional business case information specific to each project is then addressed separately.

1.0 BACKGROUND

Asset management is a necessary and critical function for YEC. As the primary generator and transmitter of electricity in Yukon, YEC is a very capital-intensive business. Additionally, YEC is facing historically large capital demands to address infrastructure reaching end of life as well as new asset requirements to address growth.

AM is the tool that allows the utility to take a holistic approach to evaluating capital investments by aligning asset management with strategic initiatives, and involves identifying, acquiring, maintaining, tracking, upgrading, and disposing of assets to maximize their value while minimizing risks.

Prior to 2017, YEC relied on an informal approach to AM. While that approach did contain some good AM practices, it lacked uniform roll out across the company and failed to address key functionality around asset life cycle management, including but not limited to maintenance scheduling, tracking and reporting. This conclusion was supported by an extensive review of like entities who had adopted updated AM practices. While the existing YEC systems had some good characteristics, the review concluded that YEC AM system was deficient and was not current with developments in asset management in the industry.

YEC considered three options for addressing its AM needs going forward:

1) Status quo;
2) Temporary solution using existing technology; and
3) Permanent solution using fully integrated system.

These options were measured against a number of criteria: regulatory and public interest, social, environmental and sustainability impacts; benefits and economics. The conclusion of this analysis was that it was necessary to update and modernize its AM system by putting in place a permanent solution that included adoption of industry-standard AM practices with a technology platform capable of supporting these new practices.

For more detailed background on YEC AM development since 2017 see Attachment 5.3A-1 for METSCO's detailed report on YEC's AM system review and business case options analysis.

2.0 OVERVIEW OF AM ACTIVITIES TO DATE

As part of the GRA 2021 application, YEC had applied for rates sufficient to pay the capital investment in the sourcing and implementation of the EAM system. Total investment forecast for completion in 2021 was $4.938 million.

In the 2021 GRA application, YEC documented the feasibility exercise conducted in 2017/18 to assess the current asset management (AM) system that was then in use. This study concluded that the then current computerized system used for AM was not consistent with industry standards and did not have the functionality to meet this standard (2021 GRA - YUB-YEC-1-64(b)). In parallel, a study of existing standards and practices confirmed that YEC's AM framework overall did not meet the requirements of industry standard as described in ISO 5500X.

YEC's Board subsequently approved two related projects: (1) to update standards and practices to industry standard (which later became known as PAMMS); and (2) to purchase a computerized system with necessary functionality to support the new framework developed in (1) (EAM).

Further, management determined that it would be necessary to acquire and implement the computerized EAM system prior to the completion of the framework project due to the staged implementation of the policy and procedure updates. This strategy resulted in the EAM appearing in the 2021 GRA application to address this staged framework implementation. The framework itself was not to be completed until 2023.

In the YUB decision on GRA 2021 (para 332 of Appendix A, Board Order 2022-03), the Board acknowledged that "there is a requirement to keep asset management practices aligned with industry standards such as ISO 55000." However, the Board disallowed YEC's costs for the EAM based on the following two concerns (para 332 and 333 of Appendix A, Board Order 2022-03):

- The Board noted that YEC had explained the benefits expected from implementation of the EAM project but expressed concern that the evidence presented lacked project-specific evidence (for example, YEC could not provide any organizations that showed the benefits being assumed in YEC's analysis); and

- The Board expressed concern that YEC did not describe the "technical merits" that led to the selection of the Infor software package in the EAM project.

In response to the concerns identified by the Board in its GRA 2021 decision, YEC retained METSCO in 2023 to review the studies previously conducted by YEC to assess the existing AM functionality for YEC's assets and to investigate and establish the value for cost by improving YEC's historical asset management function and making long-term changes based on YEC's analysis of its historical state and industry insights (see Attachment 5.3A-1 to this Appendix 5.3A).

The METSCO report's key objectives included the following:

- **Data Collection**: Collecting data on YEC's AM practice as needed to perform the assessment;
- **Industry Comparison**: Comparing and contrasting YEC's AM practices against industry standards and peer utilities;
- **Options Analysis**: Defining the different basic options that YEC had to undertake for their AM practice, and comparing and contrasting these options, leveraging both qualitative and quantitative metrics and results; and
- **Business Case Conclusions**: From the Options Analysis, identify the most optimal option for YEC to pursue, based on the net benefit analysis.

The METSCO report confirmed the three options that YEC had identified in 2017 for addressing its AMin the future:

- Option 1: Status quo (pre 2017 state retained moving forward);
- Option 2: Temporary solution using existing technology (essentially PAMMS without EAM); and
- Option 3: Permanent solution using fully integrated system (PAMMS with EAM).

METSCO measured those three options report against a number of criteria: regulatory and public interest, social, environmental and sustainability impacts, benefits, and economics. The METSCO AM business case analysis concluded that the optimal approach was a permanent solution for YEC that includes adoption of industry-standard AM practices (i.e., PAMMS) with a technology platform capable of supporting these new practices (i.e., EAM).

METSCO's report includes a financial analysis of benefits and costs for the three options, reviewing initial capital costs as well as ongoing operating costs versus financial benefits under a range of categories over

10 years for PAMMS and 12 years for EAM. The following Net Present Values were estimated for each of the options using YEC's 2021 Weighted Average Cost of Capital of 5.22%/year, confirming the financial business cases for both PAMMS and EAM projects:

- Option 1: Base Case NPV negative - $19.0 million
- Option 2: PAMMS NPV positive $7.4 million
- Option 3: PAMMS with EAM NPV positive $11.1 million

3.0 INTERDEPENDENCY OF ASSET MANAGEMENT / PAMMS AND EAM

As reflected by the METSCO report, it is critically important to recognize that, despite the fact that they were implemented as separate projects, the EAM and PAMMS projects are closely related and interdependent components of YEC's AM program.

It is not feasible that an asset management program, work management system, capital forecasting, asset register, and KPI data collection be performed with spreadsheets. These components can be tested individually using spreadsheets, but spreadsheets are disconnected.

In reality, these elements work in an interconnected way that is not possible to manage without an integrated software solution. This is the reason for the EAM project, and it is the reason for EAM software's rise in the marketplace as a business solution. In other words EAM is the enabler for Asset Management.

To make good decisions, actual data and information are required.

EAM contains the data on the assets which is used for decision making, and the data is developed using the processes and decision-making frameworks (Asset Health, Criticality, Risk, Capital Planning) which make up the asset management system. That data in EAM is kept up to date through the course of performing maintenance and inspection work on actual equipment in the field. In this way, the pieces of the asset management system work together, but necessitate the need for software as a means of managing the data and its upkeep through people and process.

Specific issues related to the review of actual activities and expenditures for both the PAMMS and EAM projects are further addressed in Sections 5.3A-1 and 5.3A-2 below.

SECTION 5.3A-1: PAMMS ASSET MANAGEMENT FRAMEWORK (RATE BASE ADDITION OF $5.466 MILLION IN 2023 RE: 2018-2023 EXPENDITURES)[1]

The Physical Asset Management Managed System (PAMMS) is a multi-year project started in 2018 (before the PAMMS name was coined). It was brought into rate base in 2023 and as noted above involves the formal documentation of all governance, roles and responsibilities, processes, and procedures required for the establishment and ongoing operation of YEC's asset management system.

The METSCO report (Attachment 5.3A-1) fully addresses the relevant AM YEC background, industry standards, options, and PAMMS net financial benefits that support its selection as a prudent expenditure for YEC – and the critical interdependency between the PAMMs and EAM components of YEC's AM framework. This Section further describes the PAMMS project's specific activities and costs since 2018.

As noted PAMMS costs to be included in 2023 rate base commenced in 2018, reflecting management decisions in 2017 to initiate an Asset Management Framework project. A first phase of activities occurred over 2018-2019. A second distinct phase concluding this work occurred from 2019 to 2023. These activities are summarized below by phase - details on these activities are provided in separate attachments for each phase.

Initial Activities to 2019

The Asset Management Framework project began in 2017. The concept of developing and implementing an Asset Management Framework in alignment with ISO55000 was introduced and initiated by the YEC Senior Management Team, after a decision that simply sustaining the then current AM framework was not an acceptable option.

In 2016 YEC developed its first long term Sustaining Capital Plan to quantify the investment required over the medium term (up to 10 years) to refurbish or replace end-of-life assets. Accordingly, the drivers behind the project were a realization that a significant portion of YEC's existing generation and transmission assets were built in the 1950's and 1970's. These assets were approaching end-of-life, and required identification, prioritization, and planning for refurbishment and/or replacement.

Given the significant investment identified to sustain YEC's existing asset base at the time (~$50 million over the next 5 years in 2016, now projected to be closer to $80M/year), YEC recognized that an

[1] Expenditures of $0.439 million in 2018, $1.349 million in 2019, $1.530 million in 2020, $0.303 million in 2021, $0.835 million in 2022 and $1.011 million in 2023.

integrated approach to asset management was required to manage the risk of aging infrastructure, and to develop, justify and create support for the Corporation's future sustaining capital plans.

The management team selected a consultant, through competitive bid process, to support YEC in the development of a plan to develop and implement an asset management system. See a detailed review of this process below.

The consultant chosen worked with the YEC management team to develop the desired 'future state' vision through a workshopped process. An implementation plan, budget, and timeline were developed to achieve the future state, as seen at project inception. The initial implementation project was for a 5-year plan and included a project budget of $5.48M.

The first two years of what was called the Asset Management Framework project were approved in March 2018 at $2.08M for 2018 and 2019. The project was to be reassessed at the end of 2019, and another request for funding to complete the project submitted at the December - 2019 BOD meeting.

The project plan and budget developed in 2018 for the Asset Management Framework project, with the support of the Asset Management Consultant, leaned heavily on expert consulting resources for both guidance and expertise in developing an asset management system appropriate to YEC.

Implementation of a new Enterprise Asset Management (EAM) IT system was identified in the initial work in the 5-year Vision of the project as a fundamental and necessary element of an enhanced Asset Management program. This EAM would replace and enhance the functionality of YEC's existing CMMS system. The procurement and implementation of the EAM was executed under a separate capital project. Projected benefits from AM work that included EAM were estimated based on consultant advice on relevant industry experience.

The AM work focused on YEC's critical assets and equipment, with specified boundaries as to which YEC assets were included versus not included in the program. The costs for work completed in 2018-2019 (in relation to the project that later became known as PAMMS) included costs related to planning and policy development for AM, asset data collection, maintenance plans development, AM plans for specific critical assets, and various other work and completed deliverables.

Total spending to the end of 2019 was $1.788 million, below the initial budget for this period of $2.08 million.

Attachment 5.3A-1.1 reviews in detail the following AM activities carried out by YEC during 2018-2019 to move forward with the project:

- 5 Year Vision (2018-2022);
- Projected Benefits;
- Project Boundaries;
- Work Completed, 2018-2019; and
- Expenditure Review, 2018-2019.

2020 Project Reset and PAMMS system implementation (2020-2023)

In 2019, the Director of Engineering and Capital Projects, who was the sponsor for the Asset Management project changed. With the new Director position came a review of the AM program to date, and a reset of the objectives.

The primary goals of the AM framework were retained; however, the project was altered to include specifically the PAMMS (Physical Asset Management Managed System) framework. The PAMMS framework is a collection of processes and procedures, and together form the managed system for the management of assets at YEC. The Managed System approach is about the development of internal processes for the activities within the asset management system. This is different from the earlier approach of 2018 and 2019, which relied entirely on contractor completion of deliverables for YEC, rather than the development of internal capacity so that YEC can sustain the process of asset management.

The original estimate for the Asset Management framework development project for the remaining 3 years of the project (2020-2022) was $3.021 million, including a contingency of $608K. The 2020-2022 budget had been revised and updated to $3.678 million including a risk-based contingency of $170k - there was significant uncertainty in the earlier 2020-2022 budget estimates. However, by 2020, Management had learned from the first two years of the project implementation and was confident that there was greater certainty around the scope and estimates. The contingency was therefore reduced to 5% for 2020, 2021 and 2022.

The underlying basis for the initial project estimate was to rely heavily on contractors and consultants to develop most of the project deliverables. The reset in 2020 aimed to change the approach and develop internal processes and resources for the activities within the asset management system.

Because the EAM implementation occurred coincident with the execution of the PAMMS project in 2020 and 2021, the EAM was the primary consumer of internal resources available to asset management. As a result, there was little progress on PAMMS in 2021. Subsequently, the project timeline was extended to the end of 2023 (from 2022) for the completion of the project, without a change in project budget. Project costs for 2020-2023 to complete the extensive PAMMS deliverables completed during this period is $3.678 million (total PAMMs costs from start in 2018 are $5.466 million).

Attachment 5.3A-1.2 reviews in detail the following PAMMS activities carried out by YEC during 2020-2023 to conclude the current project:

- Key 2020-2023 Project Deliverables;
- Work Completed, 2020-2023; and
- Project Financials 2020-2023 (Forecast to Project Completion).

SECTION 5.3A-2: ENTERPRISE ASSET MANAGEMENT (EAM) PURCHASE & IMPLEMENTATION (2021 RATE BASE ADDITION OF $4.550 MILLION RE: 2018-2021 EXPENDITURES)[2]

Set out below is a more detailed discussion of the EAM project.

The Enterprise Asset Management (EAM) Purchase & Implementation project is an enterprise-level software application brought into operation in 2021 (but disallowed by the Board in the 2021 GRA for inclusion in the 2021 GRA revenue requirement or rates) that enables YEC, as a key part of its asset management program, to manage and optimize its assets throughout the entire asset lifecycle including asset needs identification, asset investment planning and prioritization, advanced asset maintenance management and asset performance tracking.

Keeping in mind the concerns of the Board expressed in the 2021 GRA -- the METSCO report (Attachment 5.3A-1) addresses the critical interdependency between the PAMMs and EAM components of YEC's asset management (AM) framework and approach.

The METSCO report (Attachment 5.3A-1) fully addresses the concerns identified by the YUB in the 2021 GRA about the adequacy of the evidence presented by YEC in that application to support the EAM project. In addition, this Section further describes the EAM project to source and implement a new AM system, including the costs incurred and specifically the technical merits used to justify the selection.

Retaining Existing Computerized System Not Acceptable Option

Given the volume, complexity and varying risk profiles of the assets used by YEC to execute its mandate, a computerized system is necessary for successful implementation of a modern, robust asset management strategy consistent with current industry standards. The existing system available in 2017 was assessed and determined to be incapable of hosting the required asset management program.

As a first step to finding an appropriate solution, YEC conducted an evaluation of the then current systems to assess the ability to meet the new ISO 55000 standard. These systems were deemed inadequate. In assessing options to replace the then current systems, the EAM technology was selected.

In summary, the basis for this conclusion was as follows:

[2] Expenditures of $0.276 million in 2018, $0.534 million in 2019, $2.972 million in 2020, and $0.768 million in 2021.

- An EAM is an enterprise-level software application that enables an organization—particularly an asset intensive organization, to manage and optimize its assets throughout the entire asset lifecycle including asset needs identification, asset investment planning and prioritization, advanced asset maintenance management and asset performance tracking.

- An EAM solution differs from a Computerized Maintenance Management System (CMMS) such as Wennsoft Service (which YEC then currently used), in that a CMMS traditionally focuses on management and execution of maintenance related work while an EAM has additional functionality to track and report asset health, asset condition and criticality as well as having the ability to track actions taken for Maintain, Repair and Overhaul (MRO) of assets.

- While YEC's CMMS allows YEC to track cost and raise reactive work orders, it has significant shortcomings and is not capable of planning and executing planned preventative maintenance work requiring coordinated scheduling of materials and labour requirements, tracking asset condition and criticality, nor does it support the end worker by making equipment records and history easily available.

- The EAM is a critical foundational AM element that allows YEC to track, manage and optimize its assets in support of the PAMMS initiative.

- One of the key benefits arising out of the EAM implementation project is to ensure that YEC's asset management processes align more closely with ISO 55000 which is an international standard covering the management of physical assets. A modern EAM solution enables an organization such as YEC to incorporate its maintenance management strategies, procedures and work practices in standard operating procedures that can be followed by its service personnel.

- In conclusion, YEC could not rely on its existing CMMS and had no reasonable option to avoid sourcing a new asset management system. This was confirmed by outside experts in the area. While it is possible to run an AM program on more basic technology (for example generic spreadsheet-based software), the recommendation by supporting experts for advanced programming (e.g., asset health indices for key assets and the ability to automatically produce planned maintenance schedules) negated the use of these more rudimentary technologies. See Attachment 5.3A-1 for more detailed analysis of EAM as an option to the status quo as well as PAMMS development absent the inclusion of EAM.

Selection Process for EAM Supplier

YEC pursued an extensive process to select the EAM supplier. YEC, with assistance from consulting experts, developed a two stage process to select a replacement system:

1. Request for Statement of Qualifications; and
2. Request for Proposal

In Board Order 2022-03, the Board expressed concern that YEC did not explain the "technical merits" of the Infor system selected.

Technical merit is interpreted to be the criteria used to assess the company, its experience, its software functionality, the implementation approach to install the software and the price. These criteria are incorporated into the procurement process which is described in detail below.

Request for Statement of Qualifications (RFSQ)

The purpose of the RFSQ is to identify a list of potential vendors with product offerings that potentially could meet YEC functional requirements for an EAM computerized system. The RFSQ was published publicly through the MERX platform as well as specific invites to 27 potential vendors identified as part of an earlier request for information. The RFSQ was structured in two components:

1. Mandatory functional requirements – proponents were provided list of 19 (subsequently reduced to 18) system functions (see list in table below). This list was developed by YEC with support from AM consultants to represent the functionality YEC requires to execute an ISO 55000-compliant AM. Of the 10 bids received, 9 were deemed compliant and moved to the next stage.
2. Individual Scoring & Consensus – proponents meeting the functionality requirements in 1) were further evaluated based on the following criteria:
   a. Approach & Methodology – 200 points
   b. Proponent & Software profile
      i. Company profile – 75 points
      ii. Software profile– 75 points
      iii. References– 90 points
      iv. Support model– 60 points
   c. Solution criteria – 500 points

Number	Mandatory Requirement	Compliance	
		Yes	No
1.1	The Proponent must use the English language for all submittals, although Bi-lingual documents are acceptable. Are you able to comply with this requirement?		
1.2	The Proponent must have a North American support presence. Are you able to comply with this requirement?		
1.3	The Proponents solution must be aligned wit ISO 55000, 55001 and 55002. Are you able to comply with this requirement?		
1.4	The Proponent's solution must support a hierarchical asset register with support for different asset types and custom fields?. Are you able to comply with this requirement?		
1.5	The Proponent's solution must support a detailed asset history (failures, work orders, corrective actions taken). Are you able to comply with this requirement?		
1.6	The Proponent's solution must provide Management of Change (MoC) capabilities. Are you able to comply with this requirement?		
1.7	The Proponent's solution must support work order management (planning, execution, closeout, feedback). Are you able to comply with this requirement?		
1.8	The Proponent's solution must provide a configurable workflow system for routing, notifications, and approvals. Are you able to comply with this requirement?		
1.9	The Proponent's solution must provide a work scheduling and resource balancing mechanism. Are you able to comply with this requirement?		
1.10	The Proponent's solution must provide a mechanism for tracking a pending work backlog. Are you able to comply with this requirement?		
1.11	The Proponent's solution must allow for recording and managing asset condition data. Are you able to comply with this requirement?		
1.12	The Proponent's solution must provide the ability to attach relevant documents to work orders and assets. Are you able to comply with this requirement?		
1.13	The Proponent's solution must support asset condition monitoring and data driven workflow triggers. Are you able to comply with this requirement?		

Number	Mandatory Requirement	Compliance	
		Yes	No
1.14	The Proponent's solution must support planned (PM) and predictive (PdM) maintenance. Are you able to comply with this requirement?		
1.15	The Proponent's solution must provide a mechanism for asset health index (AHI) calculations. Are you able to comply with this requirement?		
1.16	The Proponent's solution must provide a reporting component. Are you able to comply with this requirement?		
1.17	The Proponent's solution must provide a dashboarding component. Are you able to comply with this requirement?		
1.18	It is important to YEC that the proposed solution is actively developed and maintained. As such, the proponent must have released a new version of their software solution in the last 24 months. Are you able to comply with this requirement?		
1.19	The Proponent must have had a security audit in the last 12 months. Are you able to comply with this requirement?		

Based on the combined results, YEC invited 6 bidders to participate in the RFP stage.

Request for Proposals (RFP)

Of the 6 invited proponents, three bidders chose not to pursue this opportunity. For the three submitted bids, the RFP process was further sub-divided into four stages:

1. Compliance
2. Solution Cost
3. Demonstration
4. Site Visit/Reference Checks

1 Compliance

Each submitted bid was evaluated against the following compliance criteria:

- General Competency and Capacity *(35 points)*
- Project Team Qualifications *(35 points)*
- Approach & Methodology *(35 points)*
- Project Management Control Methodologies and Strategies *(35 points)*
- Compliance to Functional Requirements (70 Points)
- Compliance to System Requirements (70 Points)
- Compliance to Corporation Security Criteria (35 Points)
- Technical References (35 Points)

All submitted bids were deemed to meet the minimum of 250 out of a possible 350 points.

2 Solution Cost – 250 points

Proponents were requested to provide 10-year product costing information to permit an expected life cycle cost for each offering. In keeping with YEC practice, the lowest bid received maximum points and higher bids were awarded lower points based on % above the lowest price.

3 Demonstration – 300 points

As part of the RFP, YEC provided a list to address all system integration and system replacement requirements for an EAM solution. This list was also communicated to vendors in the RFP with the requirement that in the live demonstration process, the vendors would demonstrate a clear technical understanding of these requirements, and present a sound strategy to meet them.

4 Site Visit/Reference Checks – 100 points

In accordance with the terms of the RFP, the top two proponents were subject to site visits/reference checks to confirm system functionality in a live environment.

Final Evaluation

The table below provides the detailed scoring for each submitted bid based on the criteria defined above.

Evaluation Summary		- PROPOSAL AND COMPLIANCE TO REQUIR				STAGE 2 - SOLUTION COST				STAGE 3 - PRESENTATIONS						STAGE 4 - SITE VISIT			
Proponent	Section	Weight - D	Pass	Score	Pass(Y)/Fail (N)	Weight	Estimated 10 Year TOC	Score	Cumulative	Weight	S1 250 Pts	S2- Technical Score 50 Pts	Total Score Stage 3	Cumulative	Rank	Weight	Score	Cumulative	Rank
INFOR SAAS	**3**	420	300	340	Y	250	Not Provided	0	**N/A**										
INFOR On Prem	**3**	420	300	340	Y	250	$4,732,654	182	**522**	300	195	41	236	**758**	**1**	100	41	**799**	**1**
Ontracks SAAS	**3**	420	300	299	Y	250	$3,453,382	250	**549**	300	154	36	190	**739**	**2**	100	43	**782**	**2**
ONTRACKS On Prem	**3**	420	300	299	N	250	$4,399,068	196	**495**	300	154	36	190	**685**	**3**	100	43	**728**	**3**

As described, Infor was the successful bidder in this process. While the results indicate that the lowest-price bid was not selected, the table clearly shows that the Infor offering had the highest combined points for functionality and cost. The functionality criteria, as described above, are the requirements determined by YEC, in consult with AM experts, to be necessary to fully implement an ISO5500X aligned program. This approach ensures that YEC and by inference ratepayers, get the optimal combination of performance and price.

Based on these results, YEC Board of Directors approved implementation of the Infor EAM solution in December 2019.

Project deliverables

In summary terms, this project was delivered in two stages – during 2018/19, Yukon Energy, with support from expert consultants, completed a detailed and thorough procurement process to ensure optimal pricing and functionality for the new solution; in 2020/21, the Corporation completed the implementation of the new system, including integration with existing legacy systems in use. The table below documents the cost breakdown by activity for each of these stages.

($000's)	Actual Cost At Completion	Description
2018/19 Costs	809	Vendor Selection & Project Initiation - A multi-stage competitive procurement was administered in 2018. A total of 27 potential suppliers were invited to participate in a request for information process. From this, 8 vendors were invited to a full request for proposal (RFP) process. As a final step, three vendors were invited to participate in vendor presentations and site visits and full cost work up. YEC was assisted in this process by KPMG, who provided expert project management services.

2020/22 Costs		
• Application Software Licenses	667	System Implementation • Design • Configure • Build Integrations • Load Data • Test • Train YEC Employees • Deploy • Post Go-Live Support
• System Implementation	1,582	
• Hardware & Facilities	393	
• Resource costs	553	
• Additional Data Loading (2021)	24	
• Change Management	149	
• Project Management & SME Support	381	
Total	**4,550**	

ATTACHMENT 5.3A-1:
ASSET MANAGEMENT BUSINESS CASE (METSCO)

Asset Management
YEC Business Case

Prepared By:

MAKING IT POSSIBLE

METSCO Energy Solutions Inc.

Disclaimer

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Asst Management: A Business Case

METSCO Report # 23-160 Revision 1.0

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List of Acronyms and Abbreviations

Acronym	**Meaning**
YEC	Yukon Energy Corporation
YUB	Yukon Utilities Board
EAM	Enterprise Asset Management
T&D	Transmission and Distribution
IT	Information Technology
NPV	Net Present Value
PAMMS	Physical Asset Management Managed System
OT	Operational Technology
IoT	Internet of Things
CMMS	Computerized Maintenance Management System
ISO	Independent System Operator
AM	Asset Management
GIS	Geographic Information System
ERP	Enterprise Resource Plan
OMS	Outage Management System
CC&B	Customer Care & Billing
A^3	Asset Analytic Accelerator
AIP	Asset Investment Planning
EDTI	EPCOR Distribution and Transmission Incorporated
HI	Health Index
THESL	Toronto Hydro and Electric Systems Limited
WPF	Worst Performance Feeders
FIM	Feeder Investment Model
EPC	ENMAX Power Corporation
AMP	Asset Management Plan
ACR	Asset Criticality Ranking
HOL	Hydro Ottawa Limited
EDR	Electricity Distribution Rate
SAMP	Strategic Asset Management Plan
ACA	Asset Condition Assessment
AMS	Asset Management System
NYPA	New York Power Authority
iSOC	Integrated Smart Operations Center
IIMM	International Infrastructure Management Manual
RCM	Reliability Centered Maintenance
CVF	Corporate Value Framework
ACS	Asset Class Strategies
AIS	Asset Information Strategy
IAM	Institute of Asset Management
CAPEX	Capital Expense
OPEX	Operational Expense
AHI	Asset Health Index

KPI	Key Performance Indicator
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
O&M	Operation & Maintenance

1 Executive summary

Purpose & Objectives

This METSCO report completed in 2023 reviews the studies conducted by Yukon Energy Corporation (YEC) to assess the existing asset management functionality for YEC's assets and to investigate and establish the value for cost by improving YEC's historical asset management function and making long-term changes based on YEC's analysis of its historical state and industry insights.

Key objectives to be achieved within this study included the following:

- Data Collection: Capturing all information and data about YEC's Asset Management (AM) practice to perform the assessment,
- Industry Comparison: Comparing and contrasting YEC's AM practices against industry standards and peer utilities,
- Options Analysis: Defining the different basic options that YEC had to undertake for their AM practice, and comparing and contrasting these options leveraging both qualitative and quantitative metrics & results,
- Business Case Conclusions: From the Options Analysis, identify the most optimal option for YEC to pursue, based on the net benefits achieved.

YEC's AM Practice

YEC relies on its physical assets, including generation and transmission assets, to achieve its business goals. However, the majority of its key assets were constructed in the 1950s and 1970s and require regular maintenance and refurbishment. As YEC is looking at significant investment in sustaining and growth capital, a comprehensive approach to asset management is crucial to ensure these investments provide the expected life of the assets for the benefit of the ratepayer without impacting services. Effective asset management requires a holistic approach, aligning asset management with strategic initiatives, and involves identifying, acquiring, maintaining, tracking, upgrading, and disposing of assets to maximize their value while minimizing risks. Failure to prioritize asset management can lead to decreased customer satisfaction, regulatory penalties, and rising costs associated with reactive maintenance. To ensure sustainable growth, YEC identified an opportunity to improve its asset management practices, leveraging Information Technology (IT) and Operational Technology (OT) and data analytics to develop a holistic and integrated strategy to align with the digitization of its operations.

Before 2017, YEC had taken an informal approach to asset management, observing industry standards and best practices, but not adequately implementing improvements necessary to better optimize the management of their electrical system cost-effectively. YEC's asset management philosophy lacked centralization and integration across all business units and was not aligned with current industry knowledge. While YEC had some good practices in place to maintain its key critical assets, there was a need for a systematic approach that encompassed asset lifecycle management, maintenance, reporting, and monitoring to maximize asset-value extraction. YEC acknowledged that effective asset management could help them leverage IT/ OT solutions to ensure business continuity, enhance performance, increase security, and reduce costs.

Industry Comparison

An industry comparison was performed by METSCO to compare YEC's practices against industry standards and leading industry practices, as well as the practices of YEC's peer utilities, to better understand how organizations are implementing and evolving their asset management systems, including underlying processes and practices. Key findings from this industry comparison include the following:

- YEC, like many of its peers, has looked to align their practices against the ISO 5500x family of standards to enhance its AM practice and underlying decision-making outputs. This AM practice is traditionally supported not by a single system, but rather by a series of processes and embedded enterprise systems working in concert to deliver planning and execution-related outputs.
- EPCOR Transmission & Distribution Inc. (EDTI) introduced an asset risk-based framework in 2015, designed to establish age, condition, and risk-based analytics for all individual assets across their system. The utility has leveraged this framework to achieve a 15% sustained improvement in reliability since 2014, including a 43% reduction in defective equipment-related outages, achieved within the first two years of introducing their framework.
    - By comparison, YEC's practice also allows for age and condition-based analytics to be generated for individual assets. YEC's EAM platform offers similar functionality to EDTI's systems concerning data centralization as well as the production of asset-level analytics, short-term and long-term investment planning scenarios & outcomes.
- Toronto Hydro-Electric System Limited (THESL) began transitioning from subjective and engineering-driven decision-making to economically-driven, risk-based decision-making in the mid-2000s, leveraging age and condition analytics for each of its assets. Through these efforts, they generated a historical-state snapshot of system performance, considering age, condition, and risk, while also comparing and contrasting outcomes of their investment programs concerning risk & system reliability.
    - YEC's AM practice is helping them to undergo a similar transition from subjective, engineering-driven decisions to objective, data-driven decision-making, leveraging age and condition-based asset analytics.
- ENMAX Power Corporation (EPC) recently began a new journey to shift away from the labour-intensive AM analytics methodology that they had in place, and towards a risk-based modelling approach that would allow for budget optimization, objective data-driven decision-making, and would ultimately ensure that their selected investments are maximizing benefits to customers while enhancing usage of existing assets. EPC has also established foundational SAMP and AMP documents to guide overall decision-making. These advancements have allowed the utility to enhance productivity & data quality and improve strategic & planning processes while prioritizing assets based on customer value.
    - YEC has established similar foundational documents and processes to manage the AM practice, including an AM Policy, SAMP, as well as AMPs for key asset classes. They have introduced new analytics, including Asset Criticality Ranking (ACR), that takes into consideration the customer impacts as part of the prioritization approach. In the same manner, as EPC, further implementation of the EAM within YEC will result in strategy and process improvements, enhanced risk analysis, enhanced data quality, as well as enhanced productivity across the organization.

Appendix B provides the full results and details concerning this industry comparison of YEC's asset management practices against industry standards, leading industry practices, as well as the practices of YEC's peer utilities.

Options Analysis

Three options were evaluated by METSCO, clearly identifying the benefits and disbenefits and the necessary information for making informed decisions about the direction of YEC's asset management function.

- Option 1: Carry on with Base Case and accept the associated risks.
- Option 2: Introduce and implement basic asset management principles using YEC's existing IT/OT systems as a temporary solution.
- Option 3: Introduce and implement basic and future-proof asset management principles with a new enterprise asset management solution integrated with YEC's financial and safety systems.

Each option was analyzed with key considerations to cover YEC's asset management service needs. The considerations include legal and regulatory considerations, public interest considerations, benefit considerations and economic considerations. To make an informed recommendation between the different options, a decision framework must be leveraged to combine the benefit/risk assessment and the financial assessment. The summarized evaluation results are provided in the table below.

Table 1: Option Assessment

OPTION ASSESSMENT	OPTION 1	OPTION 2	OPTION 3
Regulatory & Public Interest appraisal			
Regulatory / Public Interest	Negative	Positive (Low)	Positive (High)
Benefit appraisal			
Average Benefit Rating	0.6	1.9	3.7
Economic appraisal			
Net present value (NPV)	-$19.0m	$7.4m	$11.1m
ROI	1	1.24	1.49
Outcome			
Ranking.	3	2	1

Business Case Conclusions

Option 3 yields the most favourable business case for YEC, which is introducing and implementing both basic and future-proof asset management principles with a new enterprise asset management solution integrated with YEC's financial and safety systems. Option 3 is also consistent with the Yukon Utilities Board's (YUB) Order 2022-03, para 332 statement that it accepts that there is a requirement to keep asset management practices aligned with industry standards such as ISO 55000.

The qualitative metric for the benefit appraisal is along the spectrum of 0 to 4, with 0 being a negative impact/benefit and 4 being a positive (high) impact/benefit for YEC operations. A summary of quantitative benefits is provided in the table below.

Table 2: Summary of Benefits

#	Benefit Rating	Option 1	Option 2	Option 3
1	**Enhanced risk management**	2: Positive (Low) Impact/Benefit	2: Positive (Low) Impact/Benefit	4: Positive (High) Impact/Benefit
2	**Improved asset performance monitoring**	1: Neutral Impact/Benefit	2: Positive (Low) Impact/Benefit	3: Positive (Medium) Impact/Benefit
3	**Increased collaboration and communication**	0: Negative Impact/Benefit	2: Positive (Low) Impact/Benefit	4: Positive (High) Impact/Benefit
4	**Improved asset sustainability**	0: Negative Impact/Benefit	2: Positive (Low) Impact/Benefit	4: Positive (High) Impact/Benefit
5	**Future-proof asset management tools and technology**	0: Negative Impact/Benefit	1: Neutral Impact/Benefit	3: Positive (Medium) Impact/Benefit
6	**Enhance the value chain with integrated KPIs**	1: Neutral Impact/Benefit	2: Positive (Low) Impact/Benefit	4: Positive (High) Impact/Benefit
	Average Scores	**0.6**	**1.9**	**3.7**

The following table highlights the summary points for Option 3 regulatory and legal considerations, public interest considerations, and sustainability considerations.

Table 3: Option 3 Summary of Considerations

Category	Option 3 Summary
Regulatory & Legal	• The YUB reviews costs related to infrastructure building, operation, and maintenance, financing of debt incurred from investment activities, depreciation and amortization costs, and other necessary costs for providing affordable and reliable service to customers. • The YUB ensures that YEC provides "just and reasonable rates for the provision of electricity" through public hearings and extensive reviews of their financial requirements. • Ultimately, this option enables YEC to provide holistic, data-driven justification to support their investments as part of regulatory reporting processes.
Public Interest	• YEC uses EAM to communicate risks, challenges, and forecast outcomes related to system reliability, safety, and environmental challenges in a data-driven manner. • EAM is used in customer consultation procedures such as Town Hall events to communicate system-wide and localized issues and challenges and provide transparent information about the asset base. • EAM improves stakeholder engagement and communication process by producing necessary reports quickly and transparently communicating the need for capital and maintenance-related activities.
Sustainability	• Implementing asset management principles and an EAM simultaneously helps YEC provide sustainable and reliable electricity to their customers while establishing critical safeguards against external factors. It will also allow YEC to strengthen their alignment with the ISO 55000 standard.

	• Transition towards a forward-facing, integrative EAM system to enhance reliability and support sustainability practices while optimizing expenditures. • A right-sized approach that accounts for YEC's current and future needs and aligns with its strategic objectives, despite being capital and resource-intensive in the short term.

The table below shows the total net costs and differences as assessed by METSCO, including the one-time implementation costs for Option 2 and Option 3.

Table 4: Financial Summary (estimates rounded to nearest thousand)

Parameter	Baseline (Option 1)	Option 2	Option 3	Reference
Annual Productivity	($ 3,055,000)	($ 2,750,000)	($ 2,291,000)	Section 3.3.2.1, Table 13
Annual Inventory Management	($ 1,300,000)	($ 1,300,000)	($ 1,202,000)	Section 3.3.2.2, Table 14
Annual Diesel Costs	($ 118,000)	($ 100,000)	($ 86,000)	Section 3.3.2.3, Table 15
Annual Lost Recovery	($ 8,000)	($ 6,800)	($ 5,900)	Section 3.3.2.3, Table 15
Annual GHG Emission Costs	($ 10,600)	($ 9,000)	($ 7,800)	Section 3.3.2.4, Table 16
Annual productivity lost due to delays in sharing knowledge	($ 696,000)	($ 464,000)	($ 232,000)	Section 3.3.2.7, Table 19
Annual productivity lost due to inefficient onboarding of employees	($ 49,000)	($ 32,000)	($ 16,000)	Section 3.3.2.7, Table 19
Data Management Effort	($ 605,000)	($ 239,000)	($ 23,000)	Section 3.3.2.5
Extended Asset Life	$ -	$ 353,000	$ 353,000	Section 3.3.2.6, Table 18
Warranty Claim Improvement	$10,000	$ 10,000	$ 20,000	Section 3.3.2.3, Table 15
Net Costs	($ 5,830,800)	($ 4,538,000)	($ 3,492,000)	Note 1
Average Annual Efficiency (or Loss)	($ 1,816,000)	$ 1,293,000	$ 2,339,000	Note 2
Implementation Costs	-	($ 5,446,000)	($ 10,016,00)	Note 3
Support Costs	-	$ 0	($ 2,441,000)	Note 4
Net Present Value (NPV) *WACC = 5.22%* *Inflation = 2.0%* *PAMMS Period = 10 years*	($ 19,041,000)	$ 7,420,000	$ 11,086,000	Note 5

EAM Period = 12 years				
ROI	1	1.24	1.49	

Note 1 – Summation of cost estimates observed in Section 3.3.2 and Tables 13 to 19.
Note 2 – The estimated benefit (positive or negative) expected with each option, calculated through the benefits identified in Table 4.
Note 3 – Implementation costs for PAMMS (Option 2) and PAMMS with EAM (Option 3).
Note 4 – Support costs such as licensing for EAM (Option 3 only).
Note 5 - The NPVs are calculated assuming the total implementation cost ($4.550 million for EAM, $5.466 million for PAMMS) plus ongoing annual support over 12 years and project benefits as reviewed in Table 4. The NPV calculations use YEC's 2021 GRA Weighted Average Cost of Capital at 5.22%.

YEC implemented Option 3.

Through Option 3, YEC conducted an audit of its asset management program and found that it was rated as level 1, indicating immaturity in asset management practices. As a result, a multi-year plan was developed to implement the Physical Asset Management Managed System (PAMMS) which involves the formal documentation of all governance, roles and responsibilities, processes, and procedures required for the establishment and ongoing operation of the asset management system. The EAM is being integrated with Microsoft Dynamics GP and other legacy applications to provide a fully integrated solution that ties to YEC's financial and inventory management systems. Together, the EAM and PAMMS provide comprehensive data and analysis on the condition of YEC's key assets, supporting and justifying their long-term Sustaining Capital plans and financing requirements.

2 Business Case Context

2.1 Service Need

2.1.1 Service Need Statement

Effective asset management is crucial for the success of any asset-intensive organization, and YEC is no exception. YEC relies on its physical assets, including generation and transmission assets, to achieve its business goals. However, YEC is facing the challenge of constrained capital resources while maintaining service with aging assets. The majority of YEC's key assets were constructed in the 1950s and 1970s. All assets and equipment require regular maintenance, refurbishment, and renewal to ensure continued reliable service delivery.

As YEC's critical generation and transmission assets approach the end of their lifespan, they face the daunting task of refurbishing or replacing these assets. As YEC is looking at significant investment in sustaining and growth capital, it is crucial for YEC to take a comprehensive approach to asset management, ensuring that these investments will provide the expected life of the assets for the benefit of the ratepayer, without impacting the services to which YEC is committed. Effective asset management is a vital aspect of YEC's long-term success, requiring the efficient and effective management of physical assets throughout their entire lifecycle. To achieve this goal, a holistic asset management approach is essential to aligning asset management with strategic initiatives. This systematic and strategic process involves identifying, acquiring, maintaining, tracking, upgrading, and disposing of various types of assets to maximize their value while minimizing risks associated with them.

As a utility provider, ensuring efficient service delivery to customers is crucial, and a reliable and cost-effective asset management system is vital to achieving this. However, without a proper asset management strategy, several challenges such as unplanned downtime, increased operational costs, and potential safety hazards can negatively impact customers and stakeholders. To meet growing customer demands, YEC must invest in its asset management systems by developing a comprehensive asset management plan and implementing a strategic asset management framework. This will enable effective management of asset lifecycles, optimized maintenance schedules, optimize spare parts inventory, and enhanced reliability to meet regulatory obligations.

To optimize resource allocation, reduce downtime, and increase efficiency, there is a growing need for YEC to improve its asset management practices given the aging infrastructure and increasing demand. A comprehensive asset management strategy that incorporates IT/OT and data analytics can provide valuable insights into asset performance, maintenance requirements, and future investments. Failure to prioritize asset management can lead to decreased customer satisfaction due to service interruptions, increased regulatory penalties for non-compliance, and rising costs associated with reactive maintenance.

It is therefore imperative for YEC to invest in improving its asset management practices by leveraging IT/OT and data analytics to ensure sustainable economic growth. The field of information management is rapidly advancing with the use of data analytics, enabling utilities to gain valuable insights for asset and system management. Digitization is not a new concept; the convergence of OT and IT has been ongoing for over two decades. The emergence of the Internet of Things (IoT) is disrupting traditional monitoring and control architectures, and, over the next few years, YEC must develop a holistic and integrated strategy to align with the digitization of its operations. In this digital age, data is currency, building models for simulation and prediction of the future that can identify areas for optimization and automation.

Effective asset management is critical to the YEC's success, and the consequences of not investing in it can include decreased reliability, increased operational costs, potential safety hazards, and negative impacts on customer satisfaction. Therefore, YEC has identified a need to plan and implement a corporate asset management framework to improve and optimize the management of their corporate assets and their associated performance, risks, and expenditures over their lifecycles.

2.1.2 Historical state

In 2017, before the implementation of YEC's PAMMS, YEC began conducting a review of its asset management practices. The necessity for this review was reflected in the need to maintain an aging electrical system while balancing changing workforce demographics, an evolving regulatory landscape, and the upcoming obsolescence of existing asset management technology. Before the review, YEC was aware that the majority of utilities in North America were experiencing pressures to continuously improve and have adopted best practice elements of asset management, consequently realizing improvements in their operations. Historically, YEC has taken an informal approach to asset management; this allowed for YEC to maintain the bare minimum of its asset management framework (comprising of practices, people competencies, data information, systems, and tools) while observing the growth and innovation of other utilities were testing within asset management. However, YEC had reached a point in which the state of its asset management framework was no longer designed to adequately manage its aging electrical system and its practices need to be re-aligned or updated with sound public utility practices.

YEC found that many of the drivers of change that were influencing the asset management journeys of other utilities applied to themselves. Much like their peers, a significant portion of YEC's electrical system assets were constructed in the 1950s and 1970s. As a result, a high quantity of assets was aging beyond their expected useful service lives. Maintaining the safe and reliable operation of YEC's electrical system would require increased investments in the planned refurbishment and replacement of electrical system assets going forward.

While YEC's electrical system continues to age, they are also experiencing a demographic transition within its workforce. YEC's staff are responsible for many facets of the YEC's asset management, including strategic planning and decision-making. Approximately 67% of YEC's staff will be eligible for retirement in the next 10 years.

The utility regulatory landscape across Canadian provinces and territories is also evolving. Regulatory boards have issued new budget application guidelines that require more advanced data and information as part of regular applications. While these guidelines may be subject to change, YEC must understand what may be required to adhere to possible requirements set by its regulator as well as its stakeholders.

Before their 2017 review, YEC found that their existing asset management approach was not well-suited to meet their asset management needs. The existing approach with supporting software modules had been in use for over 20 years, but it had become functionally limited and required immediate replacement. While the first maintenance module was helpful, it proved to be insufficient for managing assets. As a temporary solution, SharePoint and Excel lists were utilized. Overall, the convergence of an aging electrical system, changing workforce demographics, an evolving regulatory landscape, and technology obsolescence necessitated a review of YEC's asset management practices.

The review commenced with an independent assessment of YEC's historical approach to asset management. The assessment determined YEC's maturity across the clauses that comprise good asset management range between *aware* and *developing*. The primary objective of the asset management review was to ensure YEC's asset management practices were adequately designed to manage its aging electrical system. Operational requirements, industry trends, and regulatory requirements were key inputs that were considered as part of this review.

The review found that YEC had some good practices in place to maintain its key critical assets. First, it found that YEC exhibited the characteristics of a strong engineering and technical-based organization, where knowledge and adherence to technical requirements and regulatory/legislative mandates are ever-present. Distribution and transmission lines are inspected with deficiencies prioritized for correction based on severity. High-priority deficiencies were and continue to be corrected during the year in which they were identified, while other deficiencies are corrected in a planned manner through preventative maintenance or rebuild projects. These projects target YEC's oldest and most deteriorated transmission lines; however, YEC did not maintain a long-term rebuild strategy. Substations were inspected to identify deficiencies and required maintenance. Equipment that failed or was at imminent risk of failure was addressed through corrective maintenance or major refurbishments. Projects also existed to modernize specific types of substation equipment, such as obsolete protection and control equipment.

Generating plants were and continue to be inspected by technical staff to identify deficiencies. Equipment that failed or was at imminent risk of failure is addressed under corrective maintenance programs for hydro plants and thermal assets, as well as rehabilitation projects for civil works. Major plant refurbishment projects, such as penstock replacements, were accompanied by economic analyses to confirm that the continued operation of a plant is the least costly for customers.

In summary, YEC's historical state asset management philosophy lacked centralization and integration across all business units and was not aligned with industry experience at the time. While practices vary among utilities, certain positive trends have emerged in recent years that YEC had not yet incorporated into its operations. For example, one such trend has been the use of asset health indices to quantify the condition of electrical system assets. The absence of holistic asset management practices created challenges for YEC in managing asset investment cycles effectively, from initial decision-making to implementation, maintenance, and disposal of assets. YEC acknowledged that their industry peers use a systematic approach, employing standards and guidelines to optimize asset value realization. This includes an asset management framework that encompasses asset lifecycle management, maintenance, reporting, and monitoring.

As part of YEC's asset management process, YEC also recognized that effective IT and OT in asset management is crucial to ensure business continuity, enhance performance, increase security, and reduce costs. As technology continues to play a critical role in business operations, addressing IT/OT asset management can help organizations optimize the value of their IT/OT assets and minimize risks. To support a systematic approach to maximize asset-value extraction, YEC committed to and initiated the implementation of an enterprise asset management (EAM) system.

2.1.3 Targeted Benefits

The adoption of industry-accepted asset management practices enabled YEC to target the following potential benefits over a long-term period.

Table 5: Long-term Benefits

Targeted Benefit	Description
Enhanced risk management	Updating YEC's asset management framework can enhance YEC's risk management practices to identify, understand, and effectively manage the potential impact of risks on their operations.
Increased reliability and availability of assets	Proper implementation of the standard can lead to increased reliability and availability of assets, resulting in improved service quality and customer satisfaction.

Targeted Benefit	Description
Improved financial performance	The framework promotes a lifecycle approach to asset management that can help utilities to optimize their investment decisions and improve their financial performance over the long term.
Improved regulatory fulfillment	Aligning with industry-accepted asset management practices can help utilities meet evolving regulatory requirements related to asset management, leading to rate application success.
Continuous improvements for safety and environmental performance	The framework emphasizes the importance of considering safety and environmental factors in asset management. By aligning with industry-accepted asset management practices, YEC can continuously improve their safety and environmental performance.
Enhanced stakeholder confidence	Implementation of the framework can demonstrate a commitment to best practices in asset management, which can enhance stakeholder confidence in the YEC's operations and financial performance.
Improved organizational efficiency due to improved asset management practices	The framework encourages a systematic approach to asset management that can lead to improved organizational efficiency and effectiveness. It offers streamlined work planning and execution processes, reducing the time and effort required. The associated AM tools and transparent processes ensure a seamless workflow, without any complications. By simplifying tasks and minimizing frustration, the practice can also help to boost employee motivation, leading to a more engaged workforce.
Improved asset data management for better decision-making	By right-sizing YEC's asset management process with industry-accepted asset management practices, YEC can improve their asset data management practices and ensure that they have the right data to support decision-making. This can help YEC make better-informed decisions related to asset maintenance, replacement, and usage. Furthermore, the practice promotes a systematic approach to decision-making, which can help YEC make better decisions related to asset management.
Improved asset lifecycle management	The framework promotes a lifecycle approach to asset management, which can help YEC manage their assets throughout their entire lifecycle, from acquisition to disposal. This can result in more efficient use of assets and reduced waste.
Improved asset performance monitoring	The framework emphasizes the importance of monitoring asset performance and using data to optimize asset maintenance and replacement decisions. By aligning with industry-accepted asset management practices, YEC can improve their asset performance monitoring practices and ensure that its assets are performing as expected. An enterprise asset management solution can provide utilities with real-time visibility into their assets, including their location, status, and performance.
Increased collaboration and communication	The framework encourages collaboration and communication between different stakeholders involved in asset management. By aligning with industry-accepted asset management practices, utilities can improve their collaboration and communication practices, leading to better outcomes and more efficient use of resources.
Improved asset knowledge management	The framework emphasizes the importance of capturing and sharing knowledge related to asset management. By aligning with industry-accepted asset management practices, YEC can improve their asset knowledge

Targeted Benefit	Description
	management practices and ensure that knowledge is shared effectively across the organization.
Improved asset sustainability	The framework encourages a sustainable approach to asset management that can help YEC reduce their environmental impact and ensure that its assets are managed in a way that is sustainable.
Future-proof asset management tools and technology	The project would help YEC stay efficient and effective by investing in adaptable tools to evolve to reduce YEC's organizational risk and optimize its operations for long-term success.
Enhance the value chain with integrated KPIs	By integrating Key Performance Indicators (KPIs), decision-making silos can be eliminated, and better behaviours can be instilled in the operating culture, leading to improved collaboration with service providers and original equipment manufacturers (OEMs). Furthermore, such integration could enhance relationships with joint-venture partners and clients by providing greater transparency on aspects such as time to market and royalties.

While updating its asset management framework has several potential benefits, YEC acknowledged short-term disadvantages that may arise from this effort. These include increased costs related to consulting, training, and development, as well as the need for additional resources such as time, personnel, and infrastructure that may impact operational efficiency and strain budgets. Additionally, implementing such changes may require significant change management efforts and ongoing attention.

2.2 Base Case

For METSCO's analysis, we considered YEC's historical, pre-2017 state as the base case scenario. YEC's base case asset management practices were variable, depending on the functional area. Transmission and distribution (T&D) assets had good records and a well-documented maintenance program. Major and critical equipment and generators had inspection and overhaul programs which were developed over time based on experience and direct knowledge of equipment.

Once a need had been identified through inspections, a project intake description was completed that leads to the capital budget process, or an operations/maintenance activity.

Before the introduction of YEC's PAMMS and EAM, there was no formalized process to take asset condition assessments into account. Rather, YEC executed an informal process whereby engineering judgment in combination with selected in-field information would be leveraged to identify and prioritize projects on a case-by-case basis. The health and degradation pattern of the asset was not tracked over a multi-year time frame.

Before 2017, there was no process step for optimization between OPEX and CAPEX. The failure to carry out the evaluation would result in missed opportunities for cost savings for YEC. Alternatively, the evaluation helped to justify the deferral of a capital project for a certain amount of time within acceptable risk tolerances.

Internal YEC budget approvals and regulatory approvals existed as a series of steps where ideas for different projects were evaluated based on scope, cost, risk, benefit, and other criteria. Project ideas were vetted, refined, and improved to address very specific needs. If there were multiple project suggestions for the same asset, one was chosen as the preferred solution moving forward. Projects were then informally ranked based on various criteria including the perceived strategic value of the project.

Once projects were approved, detailed engineering and construction were prepared. YEC used various project management forms and systems to manage projects with information challenges often being present throughout. Once the project was complete, the asset continued to be maintained and operated by the operations business unit. The operations business unit maintains a variety of information on the assets such as asset inventory, maintenance schedules, maintenance logs, outage data, and consumption data. Before 2017, although the information was collected, more could be done to easily avoid time-consuming issues. For example, some information was collected on paper but not converted to electronic storage for further processing. This led to YEC's resources spending a significant amount of time locating the necessary information for future work justification.

Before the procurement of its new EAM system, YEC's computerized maintenance management system (CMMS) allowed them to track costs and raise reactive work orders. However, the CMMS had significant shortcomings. For instance, it was not capable of planning and executing planned preventative maintenance work that required coordinated scheduling of materials and labour requirements, tracking asset condition and criticality, nor did it support the end worker by making equipment records and history easily available.

The previous asset management IT/OT environment captured and retained asset management data across multiple systems that were serving the organization across several functions. The applications environment included Microsoft Dynamics GP (including add-ons Paramount WorkPlace, and WennSoft Service—YEC's historical CMMS, and Wennsoft Job Cost—a capital job tracking solution), ADP payroll application, SharePoint, and Prophix. The previous applications environment lacked key asset lifecycle management functionality needed by YEC, including preventative maintenance planning and execution, integrated material and resources planning and scheduling, asset condition and asset performance tracking, work history and cost analysis, and asset replacement history. In summary, the previous set of applications in use by YEC was not able to provide one 'source of truth' for asset lifecycle management and maintenance planning and execution, hence the need for a new EAM.

Lastly, there was no company-wide staff-level resourcing plan for asset management functions. Staff skill sets and the work hours available (people) are an asset to YEC. As technology changed, the need for certain skill sets increased, and others decreased. These changes occurred in the industry at different times and were identified by significant technology changes and were complimented with changes in skill sets, parts supply chains, and services offered by YEC.

2.3 Strategic Considerations

2.3.1 Strategic Alignment

In addition to the stated benefits targeted, the adoption of industry-accepted asset management practices aligned with YEC's corporate strategic plan by overtly supporting several strategic objectives, as identified in YEC's 2022 mid-term strategic review. The below selection highlights selective alignments between YEC's proposed PAMMS initiative and YEC's strategic plan illustrating the clear delivery of value the proposed asset management practices will deliver to YEC and by extension to the people of the Yukon.

I. Generate Reliable and Sustainable Electricity

The asset management practices implemented by YEC have and will continue to allow them to establish enhanced awareness of their assets, leading to continued refinement and optimized delivery of the capital & maintenance investment programs, which will derive the following benefits:

- Optimizing Asset Useful Life: Allowing their assets to reach their useful lives as practicably as possible through optimized delivery of maintenance, monitoring, and repair activities.
- Managing Reliability: Proactively replacing assets before their failure, based upon age, condition & risk results, thereby mitigating the impacts of an outage event.
- Enhancing Asset Sustainability: Proactively replacing legacy assets that no longer align with YEC's standard operating practices, while also introducing elevated safety and environmental risks within the organization.

In addition, the asset management practices will continue to allow YEC to move "beyond the asset" to establish awareness of the grid as a whole, which will derive the following benefits:

- Managing Capacity Constraints: Through enhanced monitoring of transmission line & substation assets, YEC will gain the ability to monitor and manage capacity risks in a near-real-time manner. YEC can leverage this information to coordinate and prioritize system reinforcement and capacity upgrades with sustainment and condition-driven projects.
- Adapting to Climate Challenges: Enhanced maintenance and monitoring programs will allow YEC to develop and prioritize system hardening programs, to better safeguard the grid from extreme weather impacts.
- Enhanced Visibility for Renewable Integration: Leveraging the results from enhanced monitoring of transmission line and substation assets, YEC will be able to support the optimal integration of sustainable/renewable energy generation projects.
- Enhanced Visibility for Interconnections: YEC can identify critical transmission interconnection components that are nearing end-of-life, along with potential capacity constraints, to prioritize interconnection rebuilds and extensions.

Ultimately, these aforementioned enhancements to asset & grid awareness will also continue to result in data-driven, objective and prudent justification to support YEC's capital & maintenance investments as part of regulatory reporting to the YUB. Through the advanced insight and planning capabilities afforded by the proposed asset management practices, YEC will be able to optimize hosting capacity evaluations, interconnection analyses, costings, and execution, streamlining both process and costs associated with adding sustainable sources of generation to their grid in a reliable manner.

II. Secure Sustainable Long-Term Financing

YEC's plan to introduce industry-accepted, centralized asset management practices will continue to greatly support the organization in its objective to improve the sustainability of long-term financing. Through its ability to greatly improve asset assessment, operations, and investment planning, the asset management planning practices proposed will significantly improve the quality and defensibility of YEC's long-term forecasting outputs for debt and equity requirements.

As an example, through the introduction of age, condition, and risk-based analytics, YEC will now have the ability to derive capital & maintenance investment plans that ensure that the right actions to the right assets are delivered at the right time. These investment plans can be further optimized by taking into consideration existing constraints, including spending, resource, and system-based constraints.

Optimizing their asset management practices has also provided YEC with the improved ability to compare and contrast investment strategies by assessing the outcomes to reliability & risk as well as other factors (e.g. financial, environment, safety, etc.). As a result, YEC can establish the optimal spending profile, including the optimal mix of capital & maintenance spending, that will allow for both asset management as well as organizational objectives to be achieved.

III. Provide Outstanding, Reliable Customer and Community Value

YEC's plan to implement and utilize industry-accepted, centralized asset management practices will allow the organization to better introduce investment plans that deliver on customer value while improving reliability and overall community value. The following key benefits are expected to be realized:

- Risk-Based Planning: Through the introduction of risk-based asset management analytics, that consider the probability as well as the impacts of failure, YEC can better prioritize capital & maintenance investments that will best mitigate reliability, safety & environmental risks to the customer.
- Enhanced Customer Communications: Through the introduction of the AM practice, YEC will gain enhanced access to asset-related data (e.g. age, condition and risk-based demographics) that will allow the organization to more effectively communicate its key capital & maintenance investments, and outcomes to the customer, thereby enhancing overall community value for the organization.
- Enhanced Customer-Based Metrics: The ongoing and continued enhancement of the AM practice will allow YEC to develop customer-oriented programs to better prioritize investments. The development of customer-focused key performance and reliability indicators.

Through improved data insight and coordination, enhanced operations and maintenance planning will be possible, allowing for the determination of improved reliability metrics.

3 Considerations and Analysis

3.1 Options Long-list Considerations

3.1.1 Options Long List

To address their historical state and need, YEC in effect considered three options:

- Option 1: Carry on with Base Case and accept the associated risks.
- Option 2: Temporary solution of implementing basic asset management principles without mature support systems.
- Option 3: Permanent solution implementing basic and future-proof asset management principles with mature integrated systems.

The following sections describe the options except Option 1, which is described as the Base Case in section 2.2 of this report.

Option 2: Temporary solution of implementing basic asset management principles without mature support systems.

Implementing basic asset management principles without mature support systems involves using minimal resources and processes to manage assets. This approach typically includes basic practices such as conducting regular inspections, preventive maintenance, and asset tracking using manual or existing technology methods. While this option may be suitable for smaller utilities, it would not provide YEC with the same level of asset management maturity, visibility, and efficiency as compared to its peers. This approach may be less effective in managing risks and optimizing asset performance.

The existing YEC technology stack has grown over time with the addition of individual solutions as needs are developed. There was clear intent to maintain as much integration as possible with this progression. The existing technology stack may be sufficient to support a short-term look ahead to a digital environment but with functional constraints still present. These functional constraints would have a stopgap solution with YEC's existing technologies such as Excel, Access, and SharePoint. Certainly, around the asset management analytics of collected data, the effectiveness and optimization of data would be limited within the capabilities of existing technologies.

Option 3: Permanent solution implementing basic and future-proof asset management principles with mature integrated systems.

Implementing basic and future-proof asset management principles with mature integrated systems involves adopting a long-term approach to asset management that provides comprehensive control over assets. This approach includes implementing advanced systems that enable automated data collection, analytics, and decision-making based on real-time information. It also involves using best practices in asset management, such as lifecycle costing, risk management, and continuous improvement.

By adopting this approach, YEC can improve their ability to manage assets and reduce costs while achieving its sustainability objectives. The use of advanced systems and best practices can enhance visibility, optimize asset performance, and reduce the risk of asset failures or downtime. Additionally, implementing future-proof asset management principles can enable YEC to adapt to evolving regulatory requirements and changing market conditions.

However, this approach requires a significant investment in resources, including personnel, technology, and infrastructure, and can take time to fully implement. Additionally, YEC may face challenges in integrating disparate systems and processes into a cohesive asset management framework. Ongoing maintenance and upgrades may also be necessary to ensure that the system remains current and effective.

Despite these challenges, implementing basic and future-proof asset management principles with mature integrated systems can provide significant benefits for utilities in the long term. By taking a strategic and proactive approach to asset management, utilities can improve their ability to manage risks, optimize performance, and achieve their sustainability objectives.

Asset management is a process whereby a utility embraces a continuous improvement culture. The process of asset management also involves gathering data about equipment to make evidence-based decisions. These decisions address the total asset lifecycle and have the benefit of helping utility companies to maximize asset usage with the potential to minimize total expenditures while meeting other corporate goals.

Asset management involves making informed decisions based on the right information at the right time and using a continuous improvement approach to achieve this goal. To collect, store, analyze, and report on information effectively, a robust IT and OT infrastructure is required with information available for dashboard reporting at different levels of the organization.

One key element of this process is an Enterprise Asset Management (EAM) System. This computer system assists YEC staff in managing the data and executing work associated with asset management. In the past, some elements of these systems were termed a Computerized Maintenance Management System (CMMS). The EAM includes the functionality of a CMMS but also includes data associated with assets, material management, documents, parts lists, maintenance instructions, engineering drawings, and other support information, ties to the purchasing system and ties to the financial systems. It may also tie to other YEC computer systems depending on the degree of data to be used in asset management. For example, trending asset condition information over several visits to equipment may provide YEC with lifetime trend information and allow YEC to determine expected lifetime, and when certain interventions are required based on condition, hence overriding time-based historical practices.

Ideally, the future technology stack would support the proposed architecture and be fully integrated on a common platform to maximize efficiencies and reduce burden costs for the care and maintenance, and training of the systems.

3.2 Regulatory & Public Interest Considerations

3.2.1 Regulatory Considerations

As per the Public Utilities Act established by the Yukon Utilities Board (YUB), utilities in Yukon are required to provide their financial and rate-setting requirements, including spending requirements and associated justification, to support the execution of their capital and maintenance investment plans within their service area. To ensure that YEC meets the YUB's regulatory requirements, the justification provided within the rate-setting process should be objective, data-driven, and prudent. The information should be derived from real-world data, preferably retrieved from a centralized repository, and presented in a turn-key manner, minimizing manual processes and maximizing operating efficiencies within the organization. YEC should also provide multiple intervention options for each investment, along with complete, clear, and concise outcomes for each option and justification to support the selected option. To enhance stakeholder confidence, utilities should establish strong communication channels that allow customers to see the investment planning results and underlying justification.

YEC is governed by the Public Utilities Act established by the YUB, which operates as a rate-setting tribunal, ensuring that just and reasonable rates for electricity provision are established[1]. YEC submits information, including electricity rates and underlying capital and maintenance investments, to the YUB for an extensive review process. Within this process, the YUB reviews and analyzes YEC's financial requirements, including the costs related to building, operating, and maintaining the utilities' infrastructure, financing debt incurred from utility investment activities or financing general debt incurred by YEC, depreciation and amortization costs, and any other costs necessary to provide affordable and reliable service for customers. Through this review, the YUB assesses the fair return to YEC and its impacts on customers.

3.2.2 Public Interest Considerations

Within the scope of the regulatory reporting procedure, as established by the YUB, the public has opportunities to participate as part of hearings with YEC. The YUB must make a fully informed decision concerning the utilities' proposed investments and rates. Members of the public may participate as intervenors, providing their information and evidence that questions the evidence submitted by YEC. Ultimately, an intervenor must demonstrate that they can provide and derive useful information that will benefit the YUB as part of the deliberation process.

The public may also participate as presenters, making a statement to the YUB regarding the application being reviewed but are not required to participate in the hearing process in the same manner as intervenors. To effectively communicate its plans to the YUB, intervenors, presenters, and the public, YEC must transition from subjective, manual-driven processes to objective, data-driven processes. Each option considered by YEC had differing capabilities in transforming YEC's historical Asset Management processes, which in turn impacted YEC's ability to respond to the YUB's questions, intervenors, presenters, and the general public in a timely, prudent, and cost-effective manner.

3.2.2.1 Option 1: Carry on with Base Case and Accept Associated Risks

YEC had an indirect link between investment planning and regulatory reporting processes. The information supporting YEC's rate-setting process was manually captured and subjective in nature, with limited use of in-field testing information. YEC had minimal capabilities to verify the consistency and alignment of information collected from different sources, and limited capabilities to generate outcomes for selected investments, requiring significant time and effort for external stakeholder engagement.

Under Option 1, YEC would continue to derive capital and maintenance investments for their service area without leveraging an established EAM, resulting in limited capabilities to ensure the produced investment scenarios have optimized spending while prudently managing risk, reliability, as well as future backlogs of assets past useful life, or assets in poor and very poor condition. Without advanced condition and risk-based analytics in place, YEC may also be exposed to elevated safety and environmental risks, due to limited system-wide capability to identify non-standard and legacy assets that no longer conform to the utilities’ operating practices, as well as assets that pose greater environmental threats. The pre-2017 state would limit YEC’s ability to analyze the full impacts and benefits of their plans as part of regulatory reporting processes.

Moreover, YEC would have limited capabilities to forecast the potential impacts of their plans, including reliability, risk, safety, and environmental impacts, and minimal capabilities to compare different investment options and decisions. This would necessitate more manual effort, as well as internal costs, to effectively respond to questions

[1] “Mandate of the Board”, Yukon Utility Board (YUB), 2023.

raised by the YUB and intervenors. While YEC communicated with the public regarding the execution of specific short-term capital projects, there was minimal capacity for communication concerning long-term investment planning and scenarios that YEC had explored. Overall, any stakeholder engagement or community consultation as it related to YEC's investment plans remained a largely manual and time-intensive process to execute, with limited capability to express forecasted outcomes.

3.2.2.2 Option 2: Temporary Solution of Implementing Basic Asset Management Principles without Mature Support Systems

Option 2 would involve YEC establishing internally based analytics to prioritize assets for investment plans, assessing the future backlogs of assets past typical useful life or in poor or very poor condition. By implementing analytics, YEC would shift from manual to data-driven processes that support long-term investment planning and short-term project development functions. However, YEC's IT/OT systems would remain unchanged, requiring the introduction of new analytics using Excel-based processes. Integration of these analytics into YEC's AM processes would remain manual, lengthening the time and effort to establish investment plans for regulatory reporting.

YEC would have limited ability to forecast outcomes for each investment scenario, but the configuration of their condition-based analytics would identify legacy assets that no longer align with standard operating practices, mitigating safety and environmental risks. This option enables YEC to assess the current state of the system using data-driven methods but with limited capabilities to compare and contrast different investment scenarios.

Communication of real-time risks to the general public, YUB, and intervenors would be more effective compared to the Base Case scenario. Age-based and condition-based analytics would articulate backlogs of assets past typical useful life or in poor or very poor condition, driving the need for targeted investment plans. Stakeholder engagement would improve but would remain largely manual and time-intensive to execute. Although the information in the regulatory reporting process would be more objective, integration would remain manual.

This option still has limited ability to test the prudency of investment options and compare intervention options. Additionally, YEC's ability to verify consistency and alignment of information collected from various systems would still be limited, and they would have minimal ability to engage external stakeholders. Overall, Option 2 would allow YEC to assess their current state and support investment plans using data-driven processes, but with some limitations that would require manual effort and internal costs.

3.2.2.3 Option 3: Permanent Solution Implementing Basic and Future Proof Asset Management Principles with Mature Integrated Systems

The Enterprise Asset Management (EAM) system proposed in Option 3 offers numerous benefits to YEC. The EAM will centralize all data related to YEC's asset management practice, creating a single source of truth for all information. This will allow YEC to design reports that extract and transform data in the optimal format for regulatory reporting, minimizing manual collection and integration. The EAM system supports YEC's shift towards objective, data-driven decision-making, and enables comparison of investment options to ensure they meet the prudency test.

By leveraging the automated reporting functionality of the EAM system, YEC can support customer-focused reporting activities and clearly articulate the benefits of their investment plans to external stakeholders. The EAM system will enhance YEC's regulatory reporting capabilities, increase internal efficiencies, and improve stakeholder confidence.

The EAM system allows YEC to develop long-term investment plans that are fully optimized, taking into consideration spending, system, and resource constraints. This will result in better investment plans and short-term projects. The EAM also facilitates the identification of asset classes and sub-classes that no longer align with standard operating practices and introduces potential safety and environmental risks.

Overall, Option 3 enables YEC to provide holistic, data-driven justification to support their investments as part of regulatory reporting processes. It also allows for better communication of risks and challenges to customers in a data-driven and dynamic manner, improving customer engagement and communication.

3.3 Benefit-Economic Analysis

3.3.1 Benefits Management

As part of the assembled business case, YEC assessed the potential opportunities and risks associated with each identified benefit. These benefits are analyzed qualitatively across all three options. YEC's development and implementation of a mature PAMMS and EAM will ultimately lead to continuous improvement and further enhance their performance and intrinsic value over time.

The following introduces each benefit and describes the effect of the benefit for each option.

3.3.1.1 Benefit #1: Enhanced Risk Management

Risk is defined as the probability of failure multiplied by the impact of failure and can be represented as a score or as a quantitative value (i.e.: risk cost). YEC recently established a framework for a risk score to be calculated either at the asset level or project level, leveraging both the asset health index (AHI) results in combination with asset criticality ranking (ACR) results.

An effective AMS should allow for risks to be identified, managed, and mitigated throughout the investment planning process. This would not only be limited to the risks derived from the assets but also system-wide and organization-wide risks. The balancing of risks, in addition to cost and performance, brings YEC in closer alignment with industry standards including the ISO 5500x family of asset management standards.

Each of the options considered by YEC will have differing impacts on risk management, and these benefits are further summarized for each option below.

Table 6: Impacts on Risk Management

Option	Summary Points
Option 1	▪ Engineering judgment and no standard processes in place for asset or system risk management. ▪ YEC had a constrained insight on asset risks, which could have comprised multiple elements such as safety, environmental, reliability, financial, standards, and sustainability. ▪ Overall, these limitations would have likely led to increased and/or unoptimized costs and reduced efficiency for YEC.
Option 2	▪ The option would allow YEC to generate consistent AHI results for each asset, enabling better decision-making regarding maintenance and investments. ▪ The ACR process could be applied to both assets and projects, allowing YEC to determine the overall criticality/impact of the given investment.

Option	Summary Points
	▪ The option would have expanded the scope of risk management at YEC compared to their historical state scenario. ▪ However, the process would have remained manual, subjective, and inconsistent, requiring additional effort from YEC. AHI and ACR results would not be integrated but would be used as part of a manual process for selecting and prioritizing capital and maintenance investments.
Option 3	▪ YEC can leverage the EAM as the sole repository for risk management data, including AHI and ACR results. ▪ The implementation of the EAM presents an opportunity to shift from a manual, subjective ACR process to a data-driven and automated process, improving the accuracy and quality of results. ▪ ACR and AHI results can be brought together into a single variable within the EAM, allowing for better risk quantification and investment prioritization. ▪ The EAM allows for centralized risk analytics, providing opportunities to link the ERM program and monitor enterprise-wide risks.

3.3.1.2 Benefit #2: Improved Asset Performance Monitoring

Asset analytics, including age, condition, and risk-based analytics, provide utilities with critical insights into the current and future state of their asset base. Asset age and age demographics often represent a first step for utilities just introducing their asset management practice. Leveraging age demographics, utilities can identify backlogs of assets that are already exceeding their typical useful life. Figure 1 illustrates a typical example of age demographics results that help to illustrate existing backlogs within the utilities' asset base.

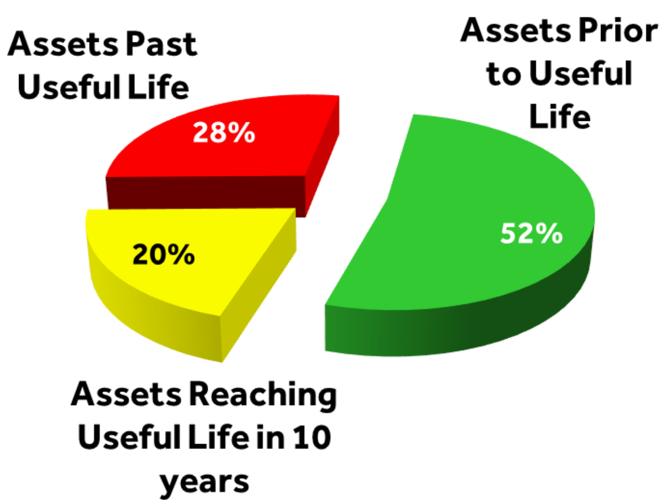

Figure 1: Example of Age Demographics Results

Asset condition assessment (ACA) often represents an incremental advancement in analytics from age, where in-field visual inspection and testing results are converted into an asset health index (AHI) for a given asset, revealing the overall condition.

Condition demographics can be used to help indicate which populations of assets are in very poor and poor condition, requiring attention within three years. Figure 2 illustrates a typical example of condition demographics results. In this case, the figure helps to illustrate year-over-year changes in the population of assets under different condition categories.

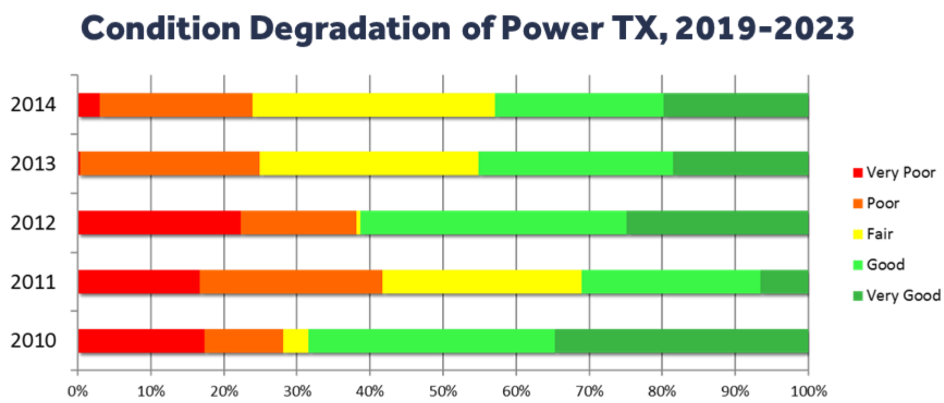

Figure 2: Example of Condition Demographics Results

Ultimately, these forms of analytics help utilities in prioritizing the worst-performing assets within their system as part of capital investment plans. At the same time, specific condition results may indicate that further maintenance and/or repair is required, thus triggering in-field maintenance and operations activities. With the advent of new monitoring technologies, utilities can now monitor their assets in a near-real-time manner, with alerts generated that can indicate if an immediate response is required. These results can also be converted into dynamic planning outputs, including a dynamic health index result.

Each of the options considered by YEC will have differing impacts on asset performance monitoring, and these benefits are further summarized for each option below.

Table 7: Asset Performance Monitoring

Option	Summary Points
Option 1	▪ YEC's historical asset performance management capabilities were limited and did not leverage asset analytics. ▪ Age demographics results could be manually generated, but the AHI framework had not been applied to generate condition-based results. ▪ System performance could only be monitored through system-wide reliability and key performance indicators but could not produce granular results for specific asset classes, ages, or conditions. ▪ SCADA data could provide real-time indications of system performance but has to be manually interpreted to support capital and operational decision-making.
Option 2	▪ YEC would have AHI results to support the development of condition demographics, in addition to age demographics, to provide a better picture of asset performance across the system. ▪ Any efforts to develop demographic results would remain manual in nature, as there would be no central system of record that could be leveraged to produce these forms of results.

Option	Summary Points
	▪ YEC would need to manage demographic results carefully to ensure that stakeholders understand when the results were produced and what data may be missing from the results. ▪ There would need to be some form of governance to ensure that the results are properly validated and updated at regular intervals, ideally managed by an "owner" of the demographics process. ▪ Assets could continue to be monitored leveraging YEC's SCADA System, but the data would still need to be manually converted and interpreted to be sufficiently integrated into YEC's AM practice.
Option 3	▪ The EAM system will serve as a centralized repository of data to support the AM practice, containing all relevant age, condition, and risk-based data associated with assets. ▪ The system will support tools to identify data quality and sample size issues, enabling YEC to enhance its data over time. ▪ Age, condition, and risk-based demographics results can be produced as standardized reports within the EAM, minimizing manual processes. ▪ In the future years, the EAM can link with YEC's SCADA system to establish a single source of data for the entire AM practice, with SCADA results converted into specific metrics for integration. ▪ The EAM can support future enhancements for monitoring assets with near-real-time data and integrating this data into investment processes.

3.3.1.3 Benefit #3: Increased Collaboration and Communication

As described in "Asset Management: An Anatomy" by the Institute of Asset Management (IAM), asset management is a team effort and requires engagement at multiple levels across the organization. It requires individuals from different functions and disciplines and will bring together contributors across multiple organizational departments, including business strategy, risk, finance, operations and maintenance, information systems, engineering, design, and construction [[2]]. Increasing the level of collaboration and communication across the organization allows for the incremental improvement of the AM practice, and the results that are produced.

Increased collaboration and communication also allow for more proactive decisions to be made within the organization concerning asset performance, resulting in the development and prioritization of capital and maintenance projects to effectively manage risk. Having a central system of record with consistent information available to all stakeholders ultimately helps foster collaboration and communication, while ensuring that all decision-making is being derived from a "single source."

Each of the options considered by YEC will have differing impacts concerning collaboration and communication, and these benefits are further summarized for each option below.

[2] "Asset Management – an anatomy, Version 3", Institute of Asset Management (IAM), 2015.

Table 8: Collaboration and Communication

Option	Summary Points
Option 1	▪ YEC held team meetings and discussions to collaborate on the development of capital and maintenance investment plans. ▪ Decisions tended to be responsive in nature due to the limited data available for AM decisions. ▪ Decision-making was subjective due to reliance on engineering judgment. ▪ Without a centralized system of record, any decisions made could be inconsistent and difficult to validate. ▪ AM decision-making information needed to be managed in a centralized system of record to improve decision-making consistency and validation.
Option 2	▪ YEC would have had access to better decision-making analytics compared to their historical state, including condition-based analytics to identify assets in poor condition. ▪ There would have been an opportunity to shift from reactive planning to proactive planning using age and condition analytics. ▪ Capital and maintenance investment plans would have still been developed through team meetings and discussions. ▪ All decision-making data would still need to be manually integrated into the AM decision-making process. ▪ Without a centralized system of record, any decisions might still be inconsistent and difficult to validate.
Option 3	▪ EAM becomes the centralized repository for all information supporting the AM practice and a collaborative communication platform. ▪ All information is derived from a "single source of truth," and processes can be defined to ensure consistency and validation of results. ▪ EAM supports the development and tracking of key performance indicators to manage the execution of AM processes. ▪ EAM can distribute actionable metrics to key stakeholders across the organization in an automated manner. ▪ YEC can considerably enhance communication and collaboration across the organization through the use of EAM, resulting in risk reduction.

3.3.1.4 Benefit #4: Improved Asset Sustainability

Overall asset sustainability can be achieved by minimizing the total costs of ownership of the asset base across their respective lifecycles. This is accomplished by performing the optimal intervention (i.e.: replacement, rehabilitation, or maintenance) at the optimal time within the assets' lifecycle, such that cost, performance, and risk are sufficiently balanced.

At the same time, the total cost of ownership for an individual asset can also be influenced by the nature of the materials used within the asset, and whether the asset in question aligns with standardized operating procedures within the organization. For example, legacy equipment that no longer aligns with standardized operating procedures may introduce additional risks to in-field crews as well as the public, which will ultimately increase risks, and the overall cost of ownership. Similarly, legacy assets that contain materials with known environmental hazards (e.g.: PCBs, lead, asbestos) will be more complex to manage, and ultimately increase organizational risk exposure while increasing the overall cost of ownership.

To mitigate these challenges, utilities are developing standardization programs that will target legacy assets for replacement across the system. These programs are designed to bring all assets into compliance with standard operating procedures, while also minimizing operating complexities and reducing the overall total costs of ownership. Each of the options considered by YEC will have differing impacts concerning asset sustainability, and these benefits are further summarized for each option below.

Table 9: Improved Asset Sustainability

Option	Summary Points
Option 1	▪ Limited capabilities to assess total costs of ownership of individual assets across their lifecycles. ▪ Decision-making information relevant to AM practice distributed across the organization within separate files and file formats. ▪ YEC would need to manually identify assets that no longer align with standard operating practices to support the development of standardization programs. ▪ Asset sustainability could not be monitored, measured, or improved due to a lack of available data to identify non-sustainable assets and quantify total costs of ownership. ▪ Overall, the historical scenario led to inefficient asset management and an inability to optimize asset interventions.
Option 2	▪ YEC could use their ACA framework and AHI results to identify assets that pose environmental and safety risks. ▪ However, AHI results would not be integrated into a centralized system of record and must be manually integrated into AM processes. ▪ Without an EAM, monitoring and measuring asset sustainability would remain challenging. ▪ Nevertheless, there may be some improvement in asset sustainability with the use of AHI results to develop programs targeting specific legacy assets.
Option 3	▪ EAM becomes the centralized repository for all information supporting AM practice and can support specific asset sustainability concerns. ▪ EAM can generate reports for assets not aligned with standard operating practices and proactively identify legacy assets. ▪ KPIs can track the effectiveness of asset sustainability programs (e.g.: the number of legacy assets replaced per year). ▪ EAM supports lifecycle costing and assessment of individual assets across their lifecycles, optimizing intervention results to balance cost, performance, and risk. ▪ Minimizing total costs of ownership enhances overall asset sustainability, better than the base case.

3.3.1.5 Benefit #5: Future Proof Asset Management Tools and Technology

Asset management remains an evolving practice as the risks and challenges within an organization continue to change and evolve. An effective AM practice must continually improve to manage existing and emerging issues, risks, and challenges. Leveraging the most modern AM tools and technologies allows utilities to extend their overall asset awareness, such that capital and maintenance investment plans can be established to optimally manage asset and system-level risks.

Each of the options considered by YEC will have differing impacts concerning the utilities' ability to future-proof their AM tools & technologies, and these impacts and potential benefits are further summarized for each option below.

Table 10: Future Proof Asset Management Tools and Technology

Option	Summary Points
Option 1	▪ YEC's AM practice was reactive and subjective under the base case scenario, relying on engineering judgment for decision-making. ▪ Information to support the AM practice was widely distributed and lacks governance to keep it up to date. ▪ It was difficult for the AM practice to manage emerging issues due to the lack of centralized tools and records. ▪ Planning for AM was reactive, with action only taken after a new risk had emerged. ▪ There were limited capabilities to monitor the effectiveness of the AM practice, hindering the introduction of new improvements over time.
Option 2	▪ YEC would have internally produced analytics to support AM decision-making. ▪ These analytics would remain within individual and disparate files and file formats. ▪ There would be limited governance to ensure regular updates of these files. ▪ YEC would need to establish ownership and ensure regular updates for individual analytics and resources to establish appropriate governance, which might have required additional manual efforts that could worsen productivity and efficiency.
Option 3	▪ The EAM is a centralized system of record for all AM-related analytical processes and activities. ▪ The EAM is a modular platform that can be updated and enhanced over time to support the evolving needs of YEC's AM practice. ▪ Governance can be applied to ensure information is regularly updated, and new technologies can be integrated into the AM decision-making process. ▪ The EAM offers a path for YEC to future-proof their AM-related tools, technologies, and processes while managing emerging issues proactively.

3.3.1.6 Benefit #6: Enhance the Value Chain with Integrated KPIs

Key performance indicators (KPIs) represent a critical element in allowing organizations to track the effectiveness of internal processes, practices, and actions. KPIs allow organizations to establish corporate awareness and ultimately link the bottom-up actions as derived from planning, operations, and engineering processes with top-down objectives and policies as established by the Executive Management Team. Linking organization objectives with AM objectives is also a critical requirement as part of asset management practices. Ultimately, KPIs allow the organization to ensure that organizational objectives are continuing to be met through the actions undertaken by the AM practice.

Each of the options considered by YEC will have differing impacts concerning the utilities' ability to enhance their value chain using integrated KPIs. The impacts and potential benefits are further summarized for each option below.

Table 11: Enhance the Value Chain with Integrated KPIs

Option	Summary Points
Option 1	▪ YEC historically monitored high-level KPIs to meet regulatory requirements with the YUB; these were managed within distributed and disparate files and file formats. ▪ Manual processes were executed to manage the updating of these KPIs, limiting YEC's ability to develop more granular KPIs. ▪ YEC could not easily introduce improvements within the AM practice due to limited data available from KPIs. ▪ Communication of KPI results was manual and reactive, with no automated processes to generate regular reports and alerts for key team members.
Option 2	▪ YEC could introduce additional KPIs that align AM objectives with corporate objectives using internally produced analytics. ▪ However, these KPIs would still be managed within individual and disparate files and file formats. ▪ YEC would need to apply governance to these KPIs, which requires additional time and resources to ensure consistency, accuracy, and regular updates. ▪ Communication of KPI results would still be manual without a central system of record and automated reporting processes.
Option 3	▪ The EAM can manage the KPI process, including the calculation and reporting of KPIs across all levels of the organization. EAM can report KPI on any process managed through EAM - thus reporting is inherently integrated with the tool itself. ▪ The EAM allows for corporate objectives to be linked to AM objectives and KPI reporting can be performed in an automated manner. ▪ The entire EAM can be governed as a single platform, ensuring information is consistent, up-to-date and accurate. ▪ Regular KPI communication reports can be established for key stakeholders and owners, allowing for proactive and efficient KPI management. ▪ YEC can easily develop new KPIs as the AM practice evolves and manages emerging issues and risks. ▪ With the EAM, YEC can enhance their value chain through the use of integrated KPIs.

3.3.1.7 Summary of Benefits

Using the following grading scale, the above-detailed benefits are graded. Note that the grading scale is subjective and is meant to compare the options against one another to differentiate which is better suited to meet YEC's needs.

Grading Scale

0: Negative Impact/Benefit	1: Neutral Impact/Benefit	2: Positive (Low) Impact/Benefit	3: Positive (Medium) Impact/Benefit	4: Positive (High) Impact/Benefit

A summary of the benefits is provided in the table below.

Table 12: Summary of Benefits

#	Benefits	Option 1	Option 2	Option 3
1	**Enhanced risk management**	2: Positive (Low) Impact/Benefit	2: Positive (Low) Impact/Benefit	4: Positive (High) Impact/Benefit
2	**Improved asset performance monitoring**	1: Neutral Impact/Benefit	2: Positive (Low) Impact/Benefit	3: Positive (Medium) Impact/Benefit
3	**Increased collaboration and communication**	0: Negative Impact/Benefit	2: Positive (Low) Impact/Benefit	4: Positive (High) Impact/Benefit
4	**Improved asset sustainability**	0: Negative Impact/Benefit	2: Positive (Low) Impact/Benefit	4: Positive (High) Impact/Benefit
5	**Future-proof asset management tools and technology**	0: Negative Impact/Benefit	1: Neutral Impact/Benefit	3: Positive (Medium) Impact/Benefit
6	**Enhance the value chain with integrated KPIs**	1: Neutral Impact/Benefit	2: Positive (Low) Impact/Benefit	4: Positive (High) Impact/Benefit
	Average Scores	**0.6**	**1.9**	**3.7**

3.3.2 Economic/Financial Analysis

As part of the business case, a financial analysis was established to develop sound and viable assessments for each option. The following introduces each benefit and describes the effect of the benefit for each option.

3.3.2.1 Benefit #7: Improved Organizational Efficiency Due to Improved Asset Management Practices

An effective asset management practice will introduce several organizational efficiencies within YEC. Before the introduction of an asset management practice, utility decision-making will typically be reactive, subjective, and primarily driven by engineering judgment. This often means that extensive manual processes must be deployed to:

- Collect and consolidate any information that will be used to inform the decision-making process.
- Analyze the information such that decisions can be defined and established.
- Share the results with an expanded AM team such that a final decision can be validated and approved.

An asset management practice allows for the collection and consolidation of information to be transitioned to a turn-key process, where this information has already been formatted in such a manner that decisions can be rapidly made, with the minimal manual analysis required by the asset planners and managers. Decision-making becomes more proactive, data-driven, and objective, with less reliance on engineering judgment.

Each of the options considered by YEC will have differing impacts on organizational efficiency, and these benefits are further summarized for each option below.

Table 13: Improved Asset Management Practices

Option	Analysis
Option 1	▪ YEC historically relied on internal expertise and limited in-field readings for investments. ▪ Prioritization and planning were manual, reactive, and subjective. ▪ Regular team meetings were necessary to convert information into decisions. ▪ Decision-making was largely subjective, leading to variable quality of results. ▪ Lack of a central system would result in inconsistent planning processes and variable efficiency levels. ▪ Historically, YEC's maintenance labour expenditure was approximate ~$3.1M annually, distributed across the different asset classes.
Option 2	▪ YEC would have age and condition-based analytics to prioritize assets within the investment plan. ▪ Information would still need to be retrieved from various systems and consolidated. ▪ Age and condition demographics would allow for a current-state assessment of the system. ▪ Project prioritization and investment planning development would still be manual. ▪ Limited organizational efficiencies would be realized under this option. ▪ With the development of an AMS, YEC would assume a 10% efficiency on their maintenance labour expenditure through the standardized processes, which is approximate ~$2.7M annually.
Option 3	▪ The new EAM system is expected to improve YEC's overall O&M performance. ▪ Proactive planning of materials and labour for preventative maintenance will be possible. ▪ Maintenance schedules will be better organized, and maintenance procedure documentation will be improved. ▪ Maintenance tracking and logistics will be improved, and the reconciliation process will be improved as well. ▪ Work order automation will be leveraged, and operators sourcing parts and components to complete work orders will be eliminated. ▪ Increased visibility of maintenance requirements and work to be completed at a particular site during a maintenance visit will improve efficiency. ▪ With the development of an AMS and implementation of an EAM, YEC can expect to standardize processes and achieve 25% efficiency on their maintenance labour expenditure, which is approximate ~$2.3M annually. ▪ YEC calculated an average of 25% efficiency between the future EAM state and the status quo process. ▪ For example, YEC's '*Issue Identification & Work Requests*' process in the historical state consisted of 11 steps (a combination of manual steps and handovers) and took about 15–20 minutes per work order request. In the future EAM process, the step count will be reduced to 7 steps (with full automation support to populate orders linked to assets) and will take about 5–10 minutes per work order request. Applying a similar concept to other processes and factoring

Option	Analysis
	in the number of employees that use the processes, the salaries and the average number of times the processes are used annually, YEC can be on average 25% more efficient.

3.3.2.2 Benefit #8: Increased Reliability and Availability of Assets

Effective asset management practices at YEC can lead to increased reliability and availability of critical assets, which are essential for providing reliable and uninterrupted services to customers. By implementing strategies such as condition-based maintenance and real-time monitoring, YEC can reduce downtime and extend the useful life of its assets, leading to improved operational performance and reduced costs. In this way, asset management can play a crucial role in ensuring the long-term sustainability and success of YEC operations.

Table 14: Increased Reliability and Availability of Assets

Option	Analysis
Option 1	▪ Within the historical state, YEC might have experienced either positive or negative impacts on the system reliability. Maintenance practices would largely remain reactive which would contribute to increased outage durations. ▪ An aging and deteriorating infrastructure would also result in more frequent outages. ▪ However, YEC did not have the capability and could not estimate the effect these factors would have on YEC's current reliability performance. ▪ The availability of T&D assets was influenced by YEC's inventory and spare management. YEC's current materials expenditure is estimated at $1.3M annually for T&D.
Option 2	▪ By introducing new asset management frameworks supported by asset data analytics with the existing IT systems, YEC could expect to reduce outage events that cause customers to lose power. ▪ Based on an industry comparative analysis, utilities that have improved their asset management framework only experienced on average a 15% System Average Interruption Duration Index (SAIDI) improvement and an 18% System Interruption Average Frequency Index (SAIFI) improvement over five years. ▪ Possible additional benefits include reduced emergency overtime for unplanned outages. ▪ The development of an asset management framework would have minimal impact on YEC's status quo inventory management. This is because the framework development focuses on business processes and simple asset analytics that would be housed in separate Excel files. The historical IT/OT environment and systems would still need to be used for YEC's inventory and spare management. As a result, the historical materials expenditure can be assumed as unchanged at $1.3M annually.
Option 3	▪ By enabling improved preventative maintenance before the point of asset failure, the new EAM system is expected to reduce outage events that cause customers to lose power. ▪ Based on an industry comparative analysis, utilities that have improved their asset management framework and introduced an EAM or equivalent asset analytic platform experienced on average a 25% SAIDI improvement and a 24% SAIFI improvement over five years. ▪ Possible additional benefits include reduced emergency overtime for unplanned outages. ▪ In the future, the framework has the potential to enhance spare parts/material purchasing planning, facilitate records and tracking, and minimize emergency repairs, thereby improving

Option	Analysis
	spare parts/material inventory management across YEC's system, extending beyond transmission and distribution. ▪ The new EAM system integrates work order planning with inventory allowing for efficiencies. ▪ Enhanced supply chain analytics to better control parts sourcing and procurement, reducing the need for operators to source parts themselves, and enabling YEC to source materials with longer lead times and improved contractual agreements. ▪ YEC undertook an inventory benchmark improvement and has identified a 5–10% cost reduction. Taking the midpoint of 7.5%, the materials expenditure is estimated at $1.2M.

3.3.2.3 Benefit #9: Improved Financial Performance

Improved financial performance is a key benefit of effective asset management at YEC. A well-designed asset management program can help YEC optimize their spending on maintenance, repairs, and replacement of assets, leading to reduced operational costs and increased revenue. By strategically investing in asset management, YEC can reduce the frequency and duration of outages and other disruptions, leading to improved customer satisfaction and reduced penalties from regulators. This can also result in improved system reliability and availability, reducing the need for costly emergency repairs, equipment replacements and the use of alternative fuels like diesel to restore power. Additionally, effective asset management can help YEC make better-informed decisions about when to retire older assets and how to plan for new investments, leading to improved long-term financial planning and better management of rate-payer funds.

For the below analysis, YEC considered the financial impact on diesel consumption, lost revenue recovery and warranty claims as these values are monitored and can be improved on.

Table 15: Improved Financial Performance

Option	Analysis
Option 1	▪ In the status quo, YEC on average used 78,362 litres of diesel fuel to provide backup power during outage restorations. Using the $1.50/litre unit price for diesel fuel, the diesel cost was ~$117,000 annually. ▪ As a result of outages and the associated durations, YEC experienced an average of $8,000 in lost revenue annually. ▪ YEC historically relied on individuals with institutional memory to be diligent in remembering which installed assets or parts are still under warranty. As a result, there was limited success in processing warranty claims for faulty parts. The historical internal estimate of successful warranty claims was minimal at approximately $10,000 per year.
Option 2	▪ With the development of an asset management framework, YEC may achieve a 15% improvement in its system reliability. ▪ Assuming this improvement, YEC estimates a reduction in diesel consumption to ~$100,200 annually with an average of $6,800 lost revenue annually. ▪ With no centralized asset records in place, YEC may not experience an improvement in its warranty claims; therefore, the estimate remains at approximately $10,000 per year.
Option 3	▪ With the development of an asset management framework and implementation of an EAM, YEC assumes a 25% improvement in its system reliability.

Option	Analysis
	▪ Assuming this improvement, YEC can estimate a reduction in diesel consumption to ~$86,500 annually and an average of $5,900 lost revenue annually. ▪ Modern EAM solutions provide the ability to track the warranty period for assets and/or parts that have been placed into service. Any subsequent corrective work orders raised against the asset and/or part can trigger a notification that the item is still under warranty and may be eligible for a warranty claim. This feature will allow YEC to track performance issues during the warranty period and apply to the vendor for remediation. YEC estimates an increase in successful warranty claims to approximately $20,000 per year.

3.3.2.4 Benefit #10: Continuous Improvements for Health, Safety and Environmental Performance

Health, safety and environmental performance are crucial benefits of effective asset management at YEC. YEC has a responsibility to ensure the safety of its employees, customers, and the environment. Effective asset management ensures that assets are maintained in a safe and reliable condition, reducing the risk of accidents and incidents. By implementing a proactive maintenance strategy, potential safety hazards can be identified and addressed before they become a risk. Additionally, an effective asset management program can help to reduce the environmental impact of utility operations by minimizing waste and optimizing energy consumption.

A comprehensive asset management system can also assist in compliance with regulatory requirements and industry standards. Compliance with safety and environmental regulations is critical for YEC, and failure to meet these requirements can result in significant fines and damage to the company's reputation. An effective asset management system can help YEC stay ahead of regulatory changes, reducing the risk of non-compliance and its associated costs.

Overall, improved safety and environmental performance through effective asset management can help YEC to protect their employees, customers, and the environment, while also reducing the risk of regulatory fines and penalties.

For the below analysis, YEC considered the environmental impact of diesel consumption only as doing a quantitative analysis on safety and all environmental impacts is a challenging exercise. No significant safety impacts were identified.

Table 16: Improved Safety and Environmental Performance

Option	Summary Points and Analysis
Option 1	▪ As previously established, YEC on average uses 78,362 litres of diesel fuel to provide backup power during outage restorations. An amount of 2.7 kg of CO2 is released into the atmosphere per litre of diesel burned. With the current carbon price of $50 per tonne of CO2, the carbon cost equals to ~$10,600 annually. **NOTE:** The carbon price is set to increase each year with the current federal plan; however, this increase is not incorporated in YEC's business case. ▪ YEC notes that although this is not a real cost, it demonstrates the potential benefit YEC can contribute to its communities by reducing its carbon footprint.

Option	Summary Points and Analysis
Option 2	▪ With the development of an asset management framework, YEC might achieve a 15% improvement in its system reliability, reducing its dependency on diesel consumption for outage restorations. ▪ The carbon cost equals to ~$9,000 annually.
Option 3	▪ With the development of an asset management framework, YEC may achieve a 25% improvement in its system reliability, reducing its dependency on diesel consumption for outage restorations. ▪ The carbon cost equals to ~$7,700 annually. ▪ Assuming a reduction in unplanned outages and associated failures, this implies a reduction in unplanned emergency work. Planned work is always safer to perform than unplanned emergency work.

3.3.2.5 Benefit #11: Improved Asset Data Management

Asset data management is a critical aspect of effective asset management for YEC. Without accurate and up-to-date information on asset conditions, performance, and maintenance history, YEC would be unable to make informed decisions on the optimal use of its assets. Inefficient data management can lead to inaccurate assessments of asset conditions, which can result in missed maintenance opportunities or unnecessary replacements. Furthermore, disparate data sources and lack of standardization can make it difficult to consolidate data for analysis and decision-making.

Improved asset data management enables YEC to overcome these challenges and improve its asset management practices. With a centralized data management system, YEC can ensure that data is standardized, consolidated, and readily accessible to decision-makers. This can streamline data analysis and reporting, leading to more informed decision-making and improved asset performance. Additionally, automated data collection and integration can reduce the risk of data errors and ensure data accuracy.

Effective asset data management can also facilitate compliance with regulatory requirements, particularly in the areas of environmental and safety performance. With centralized data management, YEC can easily access information on asset conditions and maintenance history, which can aid in identifying potential safety risks and proactively addressing environmental issues. This can result in improved safety and environmental performance, as well as reduced compliance costs.

In summary, improved asset data management can lead to more informed decision-making, improved asset performance, and enhanced regulatory compliance. Good data is required to make good decisions and assess risks. By investing in effective data management systems and processes, YEC can ensure that they are well-positioned to manage their assets effectively and efficiently, ultimately improving their overall operational and financial performance.

To assess the impact of both available and unavailable data points, the 1-10-100 rule is applied[3]. The 1-10-100 rule is a concept that applies to data management and highlights the increasing costs associated with fixing errors the later they are discovered.

[3]https://www.demandbase.com/faq/what-is-data-cleaning/#:~:text=As%20incorrect%20records%20remain%20in,in%20wasted%20time%20and%20resources

The rule states that the cost of correcting a data error increases by a factor of 10 for each stage in the data management process. For example:

- It may cost $1 to correct a data error at the point of entry, such as during data input by an analyst.
- If the error is not caught until the data is being processed, such as during data cleansing or transformation, the cost to correct it may increase to $10 to account for the time to identify the correct value.
- If the error is not discovered until the data has been integrated and stored in a database or data warehouse, the cost to correct it may increase to $100 (corrective action would be for a work request to be created to collect the data point).

This rule highlights the importance of early detection and prevention of data errors, as it becomes increasingly expensive to correct them the later they are discovered. It emphasizes the need for organizations to invest in robust data quality and management processes to catch errors as early as possible and reduce costs in the long run.

The following table presents the asset groups and counts used to assess the data. This is not an exhaustive list of all YEC's assets; it does however represent the majority of key assets that comprise the network.

Table 17: Asset Groups and Counts

Asset Group	Estimated Unit Count
Diesel assets	818
Dam & Spillway assets	172
Distribution Poles	4862
Hydro assets	1091
LNG assets	316
Transformers (inclusive of large transformers)	76
Transmission Poles	9775
Substation equipment	1900

With the historical state, most data points associated with the asset would have needed to be collected and verified. With no central database repository, these records were recorded in an Excel or Access environment. The solution has the potential to present multiple limitations to YEC, predominately concerning the manual effort required to maintain these records in an ever-growing database with increasing data points. Furthermore, without good frameworks in place, there was an element of not knowing which data points should be collected. Using the 1-10-100 rule, the effort to manage the data is estimated at approximately $604,000 annually.

With Option 2, YEC would introduce a developed data framework of key data points needed to enhance capital and O&M planning along with supporting asset analytics such as asset condition assessments and reliability analysis. However, this would be within Excel or similar environments in place at YEC with which the data records will need to be verified and updated every few years. Using the 1-10-100 rule, the effort to manage the data is estimated at approximately $239,000 annually.

With Option 3, with a developed data framework and an EAM, data is centralized, accessible and governed by everyone at YEC. Once data points are recorded in the EAM, YEC staff would only need to maintain the data quality when assets are reconfigured. Using the 1-10-100 rule, the effort to manage the data is estimated at approximately $22,800 annually. As the data input and links across the EAM processes are automated, there is less effort required by YEC staff.

3.3.2.6 Benefit #12: Improved Asset Lifecycle Management

Effective asset lifecycle management is critical for the long-term success and sustainability of YEC. The ability to optimize asset performance and extend asset lifecycles can result in significant cost savings and increased reliability, availability, and safety. With improved asset lifecycle management, YEC can minimize unplanned downtime and outages, reduce maintenance costs, and increase asset usage rates. This can be achieved through the implementation of advanced analytics and predictive maintenance techniques, which can help identify potential asset failures before they occur and proactively schedule maintenance to avoid downtime. In addition, effective asset lifecycle management can help YEC make more informed decisions about asset retirement and replacement, ensuring that assets are replaced at the optimal time to maximize their remaining useful life and avoid costly emergency replacements. Overall, improving asset lifecycle management can have a significant positive impact on the financial and operational performance of YEC.

Table 18: Improved Asset Lifecycle Management

Option	Summary Points and Analysis
Option 1	▪ As of 2018, the total cost of power-related assets was $421M and the annual depreciation was $11.8M leading to an average asset life used for depreciation purposes of 36 years. There was no annual benefit or reduction with this option.
Option 2	▪ Improved maintenance practices and the use of an EAM system could extend asset life through the application of preventative maintenance practices. ▪ Instead of relying on professional judgment and asset age, the optimal asset retirement age could be calculated by comparing the cost to maintain existing equipment versus the capital cost of replacement. ▪ YEC estimates an improvement of 3% in useful asset life (approximate average of 1.08-year increase) as a result of asset life optimization and improved reliability, resulting in savings of approximately $353,000 annually.
Option 3	▪ Improved maintenance practices and the use of an EAM system can extend asset life through the application of preventative maintenance practices. ▪ In addition to Option 2 benefits, the EAM maintains a historical record of the cost of maintenance as well as the frequency of unexpected breakdowns for each asset, which can be consolidated for asset classes. ▪ With the introduction of an EAM and the asset management framework, YEC estimates an improvement of 3% on useful asset life (approximate average of 1.08-year increase) as a result of asset life optimization and improved reliability, resulting in savings of approximately $353,000 annually. The EAM provides the benefit of having a centralized database that maintains historical records, however, the framework inserted into EAM drives the benefit.

3.3.2.7 Benefit #13: Improved Asset Knowledge Management

At YEC, knowledge management is essential for maintaining and improving operations. This includes the preservation of critical knowledge related to asset management, such as the history of asset performance, maintenance, and repair, as well as the expertise of the workforce. Knowledge preservation ensures that critical information is captured, stored, and made available for future use, even as employees retire or move on to other roles.

The use of digital tools, such as EAM systems, can play a critical role in knowledge management preservation. These systems can capture and store a wealth of information related to assets, such as performance data, maintenance schedules, and repair records. This information can be used to build a detailed history of each asset, which can be leveraged for better decision-making around maintenance and repair.

In addition to capturing and storing data, EAM systems can also help to preserve knowledge by standardizing processes and procedures. By creating a centralized system for managing assets and maintenance, EAM systems can help ensure that best practices are followed consistently across the organization. This can help to prevent knowledge loss due to employee turnover, as well as improve overall operational efficiency.

To calculate the annual productivity lost due to delays in sharing knowledge[4], a methodology is used as follows:

- The first step is to determine the total cost for one hour of work by multiplying the size of the company's workforce by its average hourly wage.
- Next, the number of inefficient hours spent by employees at the organization is determined. This includes hours per week waiting for other people to provide information, hours duplicating efforts, and hours working inefficiently in other ways. YEC assumes 5 hours.
- The inefficient hours are multiplied by 52 to make the Hours per Week calculation into an annual total.
- A Utilization Rate is applied to account for the fact that it's not realistic to proactively share all knowledge.
- An Adoption Rate is included to account for the fact that no organizational initiative or process ever has 100 percent adoption.

To calculate the annual productivity lost due to inefficient onboarding of employees[5], a methodology is used as follows:

- The calculation starts by multiplying the size of the workforce by the hourly wage of an individual employee.
- Identify and multiply the average annual employee turnover at YEC. The historical average is 10%.
- Determine the number of months required for a new employee to become proficient in their job tasks and unique work processes at YEC. YEC assumes 6.5 months.
- Multiply the number of months by the set amount of hours a new employee may work inefficiently during this learning period. YEC assumes 7 hours per week.
- The inefficient hours are multiplied by 52 to make the Hours per Week calculation into an annual total.
- A Utilization Rate is applied to account for the fact that it's not realistic to proactively share all knowledge.
- An Adoption Rate is included to account for the fact that no organizational initiative or process ever has 100 percent adoption.

[4] https://www.panopto.com/resource/valuing-workplace-knowledge/#Report

[5] https://www.panopto.com/resource/valuing-workplace-knowledge/#Report

Table 19: Summary Points: Improved Asset Knowledge Management

Option	Summary Points and Analysis
Option 1	▪ Estimated annual productivity lost due to delays in sharing knowledge is $696,000. ▪ Estimated annual productivity lost due to inefficient onboarding of employees is $49,000.
Option 2	▪ Estimated annual productivity lost due to delays in sharing knowledge is $464,000. ▪ Estimated annual productivity lost due to inefficient onboarding of employees is $32,000.
Option 3	▪ Estimated annual productivity lost due to delays in sharing knowledge is $232,000. ▪ Estimated annual productivity lost due to inefficient onboarding of employees is $16,000.

3.3.2.8 Financial Summary

The table below shows the total net costs and differences, including the one-time implementation costs for Option 2 and Option 3. It is important to note that Option 3 has ongoing support costs even after the EAM implementation.

Table 20: Financial Summary

Parameter	Baseline (Option 1)	Option 2	Option 3	Reference
Net Costs	($ 5,830,800)	($ 4,538,000)	($ 3,492,000)	Note 1
Average Annual Efficiency	($ 1,816,000)	$ 1,293,000	$ 2,339,000	Note 2
Implementation Costs	-	($ 5,446,000)	($ 9,301,000)	Note 3
Support Costs	-	$ 0	($ 2,441,000)	Note 4
Net Present Value (NPV) *WACC = 5.22%* *Inflation = 2.0%* *PAMMS Period = 10 years* *EAM Period = 12 years*	($ 19,041,000)	$ 7,420,000	$ 11,086,000	Note 5
ROI	1	1.24	1.49	

Note 1 – Summation of cost estimates observed in Section 3.3.2 and Tables 13 to 19.
Note 2 – The estimated benefit (positive or negative) expected with each option, calculated through the benefits identified in Table 4.
Note 3 – Implementation costs for PAMMS (Option 2) and PAMMS with EAM (Option 3).
Note 4 – Support costs such as licensing for EAM (Option 3 only).
Note 5 - The NPVs are calculated assuming the total implementation cost ($4.550 million for EAM, $5.466 million for PAMMS) plus ongoing annual support over 12 years and project benefits as reviewed in Table 4. The NPV calculations use YEC's 2021 GRA Weighted Average Cost of Capital at 5.22%.

4 Options Analysis and Conclusion

Options analysis is a decision-making tool used to evaluate and compare different options or alternatives to achieve a specific goal or objective. It involves a systematic process of identifying, assessing, and selecting the best option from a range of alternatives. This process involves weighing the pros and cons of each option based on certain criteria, such as cost, feasibility, and effectiveness. By using option analysis, YEC can make informed decisions that align with its goals and objectives.

The table below summarizes the reliability, benefit appraisal and economic appraisal for each option. If YEC only considers the economic appraisal, Option 3 is the most favourable. However, when YEC considers the other assessment factors, it becomes evident that Option 3 has the potential to make a significant positive impact on YEC's asset management framework.

Table 21: Option Assessment

OPTION ASSESSMENT	OPTION 1	OPTION 2	OPTION 3
Regulatory & Public Interest appraisal			
Regulatory / Public Interest	Negative	Positive (Low)	Positive (High)
Benefit appraisal			
Average Benefit Rating	0.6	1.9	3.7
Economic appraisal			
Net present value (NPV)	-$19.0m	$7.4m	$11.1m
ROI	1	1.24	1.49
Outcome			
Ranking.	3	2	1

4.1 Business Case Conclusions on Option/s (Reference Project/s)

Option 3, which entails implementing mature integrated systems to establish permanent asset management principles, is the best business case approach for YEC. The objective of the project is to develop documented and approved processes and procedures necessary for the formal implementation of a Physical Asset Management Managed System (PAMMS) at YEC, aligning their practices with industry asset management practices.

In implementing Option 3, YEC conducted an audit of its asset management program, which indicated that the organization was rated at a level 1, indicating immaturity in asset management practices. Consequently, a multi-year plan to implement an updated Asset Management program consistent with industry best practices, tailored to YEC's specific circumstances and requirements, was developed. The updated asset management program, named the 'Physical Asset Management Managed System' (PAMMS), involves the formal documentation of all governance, roles and responsibilities, processes, and procedures required for the establishment and ongoing operation and governance of the asset management system. The design of the PAMMS approach is similar to that of the EMS and H&S Management System, which were historically used by YEC.

Enterprise Asset Management (EAM) solution was identified by YEC and the above options analysis as a critical component for the successful implementation of PAMMS, as it enables organizations, particularly asset-intensive ones, to manage and optimize their assets throughout the asset lifecycle. While YEC's historical Computerized Maintenance Management System (CMMS) focused on the management and execution of maintenance-related work, an EAM provides additional functionality to track and report on asset health, condition, criticality, and actions taken for maintenance, repair, and overhaul of assets in support of the PAMMS initiative. YEC's historical CMMS was limited in its capabilities, making the EAM a foundational element allowing YEC to track, manage, and optimize its assets in support of the PAMMS initiative. The EAM is integrated with Microsoft Dynamics GP, YEC's financial management solution, and other legacy applications to provide a fully integrated solution that ties to YEC's financial and inventory management systems.

The EAM and PAMMS together are considered the asset management framework. YEC will manage the effect of new and changing business processes developed through the asset management framework with the support of YEC's Manager of Communications and change management materials developed with external support. The development of the asset management framework will establish documented business practices for YEC, ensuring that the framework becomes a persistent part of the culture and is resilient to potential risks such as the turnover of key staff.

4.2 Conclusions

Through this comprehensive study, METSCO was able to investigate and establish the value for cost by improving YEC's historical asset management function, while initiating long-term changes based upon the results of the utilities' historical state, as well as insights as established from industry standards and best practices.

Through this study, key information about YEC's AM practice was captured, such that this practice could be compared with industry standards as well as YEC's peer utilities. Different options for developing the AM practice were defined and evaluated, leveraging both qualitative and quantitative metrics & results.

From this analysis, Option 3, which represents a permanent solution for implementing future-proof AM principles with mature integrated systems, was identified as being the most effective and optimal business case option based on the qualitative and quantitative metrics & results. As per this option, YEC can leverage the full capabilities of their EAM to communicate risks & challenges while forecasting outcomes as they relate to system reliability, risk, safety, and environmental challenges. Outputs from the AM practice, including investment plans, can be produced in an objective, data-driven and cost-effective manner.

The execution of Option 3 will allow for benefits to be realized across YEC, including the following:

- Enhanced Risk Management: Ability to centralize risk management data, while incorporating risk as part of the ACR process to establish centralized risk analytics.
- Improved Regulatory Compliance and Stakeholder Confidence: Ability to establish single-source of truth for all information, thereby enhancing overall regulatory reporting capabilities.
- Improved Asset Performance Monitoring: Ability to shift towards data-driven decision-making leveraging age, condition and risk-based results, while also identifying data quality & sample size concerns.
- Increased Collaboration and Communication: Ability to establish a centralized repository and collaborative communication platform via the EAM, while developing actionable KPIs and metrics to manage the execution of AM processes.

- Improved Asset Sustainability: Ability to proactively identify assets not aligned with standard operating practices and proactively identify legacy assets.
- Future Proof Asset Management Tools and Technology: Ability to establish future-proof and modular system-of-record that can be updated and enhanced over time to support the evolving needs of YEC's AM practice.
- Enhance the Value Chain with Integrated KPIs: Ability to report on AM effectiveness leveraging integrated KPIs. New KPIs can be developed as the AM practice evolves and manages emerging issues and risks.
- Improved Organizational Efficiency due to Improved Asset Management Practices: Ability to improve O&M performance via proactive planning, enhanced maintenance scheduling, tracking & logistics as offered through the EAM.
- Increased Reliability and Availability of Assets: Ability to improve proactive maintenance resulting in a reduction of outage events & impacts.
- Improved Financial Performance: Apart from the ability to automate existing manual processes to realize productivity improvements, the EAM also allows for warranty periods to be tracked such that work orders can be triggered at the right time while the asset remains under warranty.
- Continuous Improvement on Safety and Environmental Performance: Ability to improve system reliability, thereby reducing unplanned outages and shifting from emergency to plan work activities, which are always safer to perform.
- Improved Asset Data Management: Ability to enhance data centralization and accessibility, while also being able to maintain data quality in a far more cost-effective manner.
- Improved Asset Lifecycle Management: Ability to enhance preventative maintenance practices that will lead to an extension of asset life.
- Improved Asset Knowledge Management: Ability to centralize all AM-related documentation and information, while also standardizing processes and procedures, thereby enhancing overall productivity within the organization.

The asset management framework as per Option 3 provides comprehensive data and analysis on the condition of YEC's key assets, supporting and justifying their long-term sustaining capital plans and financing requirements. A managed system, which deploys a Plan, Do, Check, and Act process, allows YEC to become more efficient in its operations, identifying improvement opportunities and defining cost-effective actions. The PAMMS program, along with the EAM implementation, is foundational and will define asset management at YEC, providing YEC with the capability and functionality to make well-informed decisions about its operating business.

Appendix A: Asset Management Background

An asset is "an item, thing, or entity that has potential or actual value to an organization." Asset management enables an organization to realize value from its assets by ensuring asset-related decisions, plans, and activities are aligned with the achievement of an organization's objectives. An asset's value can be realized by using a risk-based approach that balances costs, opportunities, and risks against the desired performance of the assets.

The Institute for Asset Management (the IAM) is an international organization that develops asset management knowledge and best practices. The IAM has produced a conceptual model showing the typical scope of asset management.

Figure A1 shows the IAM's conceptual model for asset management.

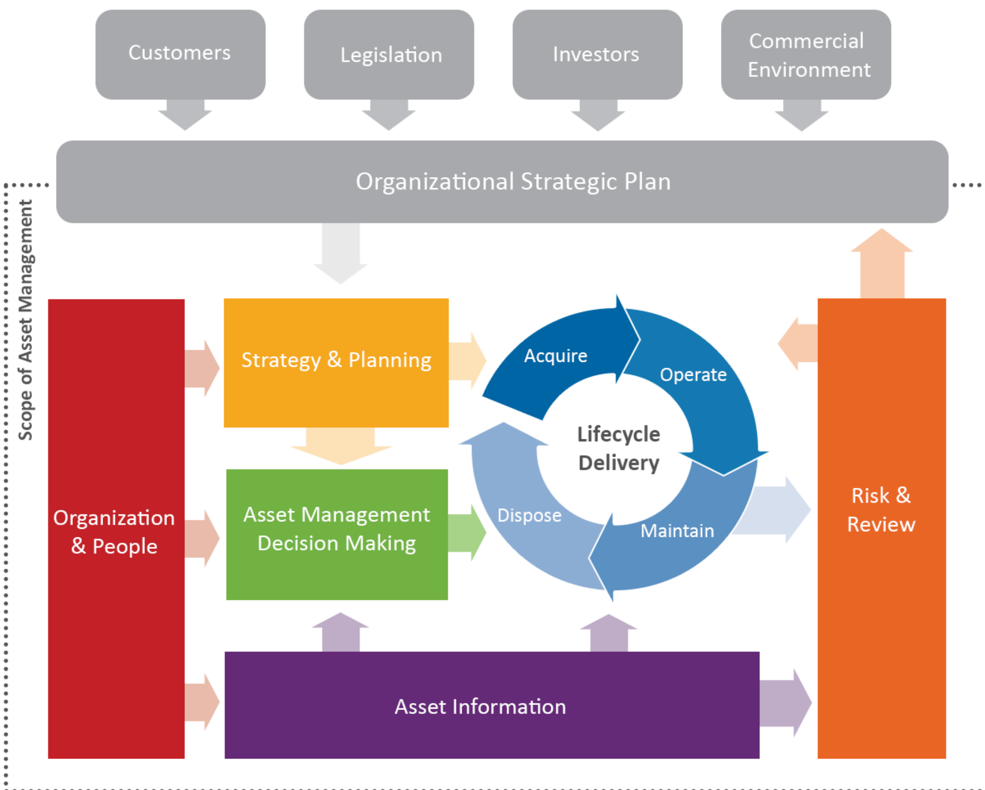

Figure A1: IAM Asset Management Model

The IAM model demonstrates that asset management is about more than managing assets. There are numerous decisions to be made across an asset's lifecycle, such as whether to buy or lease, or whether to maintain or run to failure. Asset management aims to ensure an organization makes decisions effectively across the lifecycle of an asset.

The IAM model includes six elements that are essential to the scope of asset management:

- **Organization's Strategic Plan:** Asset management should be guided by an organization's strategic plan, including its organizational objectives. An organization's strategic plan and objectives can be influenced by several external and internal factors, which can change over time. These include customers' service expectations, legislative requirements, investors' needs and the commercial environment, including economic conditions.

- **Strategy and Planning:** Strategy and planning are where top-down direction merges with bottom-up knowledge. It aims to translate organizational objectives into asset-related decisions through policies that establish principles by which an organization intends to apply asset management to achieve its objectives, and processes that guide strategic planning and detailed activities.
- **Decision Making:** Asset management decision-making is fundamentally about balancing cost, performance, and risk. A consistent, repeatable approach is required for making asset-related decisions. The decision-making process can be aided by data and technology but is ultimately a human activity that relies on the expertise of the organization's people.
- **Organization and People:** Asset management requires qualified, trained individuals in a suitably structured organization to facilitate the necessary decisions. Individuals must have competence levels that are appropriate for their roles. Visible support and engagement from top management are essential to creating a culture of effective asset management.
- **Asset Information:** High-quality asset information forms the foundation of effective asset management. Access to consistent, reliable information underpins decisions about managing an asset's lifecycle to balance cost, performance, and risk.
- **Risk and Review:** Asset management is a continual journey without an end. Internal and external environments are subject to continual change. Routine evaluations of risk, costs, and performance are required to examine whether an organization is operating effectively to achieve its objectives.

The IAM model is consistent with the clauses established in the international standard ISO 55001. ISO 55001 is a framework for asset management that contains 26 clauses that are generally accepted to reflect best practices in asset management. These clauses address key aspects for understanding the context of an organization and ensuring the appropriate leadership, planning, support, operation, performance evaluation, and continual improvement of the asset management system.

Hydro Ottawa became the first electric utility in Canada to become ISO 55001 certified in 2020. While utilities do not often seek ISO 55001 certification, the standard is generally recognized as an authoritative guideline on best practices in asset management.

Appendix B: Industry Comparison

As part of reviewing YEC's asset management practices, it was necessary to perform an industry comparison of these practices against industry standards and leading industry practices, as well as the practices of YEC's peer utilities, to better understand how organizations are implementing and evolving their asset management systems, including underlying processes and practices.

YEC, like many of its utility peers, has looked to align their practices against the ISO 5500x family of standards to enhance its AM practice and underlying decision-making outputs. In this regard, YEC's pre-2017 historical state AM practice contained key elements that aligned with each of the six strategic objectives as described in the previous section. This AM practice is traditionally supported not by a single system, but rather by a series of processes and embedded enterprise systems working in concert to deliver planning and execution-related outputs. The list below illustrates the various enterprise systems that are most typically adopted by utilities in supporting key AM processes, including long-term capital planning, short-term capital project development, maintenance planning and execution processes.

- **Geographical Information System (GIS):** Stores geospatial information, including the asset connectivity model, asset registry and nameplate data, and can also be used to store maintenance as well as analytics (condition, risk) results.
- **Enterprise Resource Planning (ERP):** This is a broader enterprise system that covers a variety of functions, including financial reporting procedures. However, ERP systems can also be used to store asset registry data and support work management procedures, and maintenance programs.
- **Outage Management System (OMS):** Stores all historical reliability event data, including customer interrupted, outage durations, cause codes, and ideally—the failed asset nomenclature.
- **Customer Care and Billing (CC&B):** Designed to manage all customer care and billing processes associated with the utilities' customer base.
- **Computerised Maintenance Management System (CMMS):** Designed to support maintenance planning, including work management, collection of in-field maintenance and testing data, and the production of HI results.
- **Asset Analytic Accelerator (A^3):** Designed to manage asset-level risk-based analytics, including age, condition, and risk-based asset assessment, as well as production of long-term investment plans, reliability forecasting, and project identification.
- **Asset Investment Planning (AIP):** Designed to work in conjunction with A^3 to deliver prioritized projects based on benefits and costs to the utility.
- **Enterprise Asset Management (EAM):** Designed to manage several functionalities, including work management, maintenance management, asset analytics (condition, risk), and project prioritization. As illustrated in Figure B1, an EAM can take on the collective role as an A*x*, AIP, and CMMS respectively.

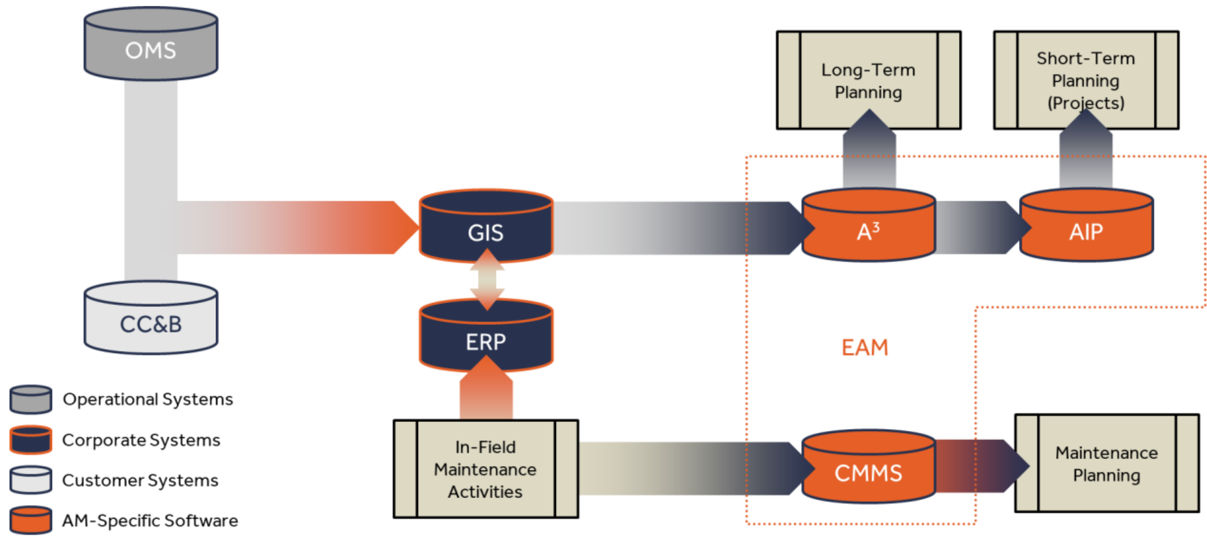

Figure B1: Typical Interactions between Enterprise Systems and the AM Practice

B1 Comparison to Utility Peers

When comparing YEC's AM practice against its industry peers, several similarities are immediately observed.

B1.1 EPCOR Distribution and Transmission Inc. (EDTI)

EDTI represents the local electric utility provider within the City of Edmonton, Alberta. As part of efforts to better align with leading industry practices and standards such as ISO 55001, EDTI has been steadily introducing and enhancing its AM practices across its T&D assets. This included the introduction of an asset risk-based framework in 2015, designed to help EDTI in establishing age, condition, and risk-based analytics for all individual assets across their system. Results from the framework were leveraged to generate a current-state assessment of asset performance, including percentages of assets past typical useful life, assets in poor and very poor condition, as well as assets beyond their economic end-of-life criteria. These results were also leveraged to develop long-term investment plans and scenarios as well as short-term capital projects.

In 2016, the utility embarked on implementing a Reliability Projection Model to help predict future outcomes of their investment plans, such that overall long-term investment scenarios could be compared and contrasted. This model helped EDTI gain a better understanding of long-term projections for system performance metrics and defective equipment, as well as yield long-term recommendations for future reliability data improvements. The utility could prioritize replacement for assets based on a balance between the risks of failure—like financial, customer, environmental, and collateral damage impacts—and the necessary costs to offset these.

As these new processes, models and frameworks were introduced, EDTI undertook efforts in enhancing their decision-making data as generated by their GIS, ERP, and CMMS systems. As an example, as part of efforts to introduce condition-based analytics within the utility, EDTI needed to re-examine and enhance their in-field maintenance processes and associated inspection forms to ensure that the right data was being collected to support the calculation of a health index (HI) for each evaluated asset. EDTI also introduced several automated reporting processes to automate the collection, classification, and formatting of input data for AM decision-making analysis. As an example, automated reporting was established within the utilities' GIS system to capture and quantify the impacts of failure for each asset, such that the risk of failure could be calculated for each asset.

In 2017, the EDTI began expanding their risk-based methodology to maintenance programs to better ascertain the relationships between maintenance program execution and the performance of their assets, such that capital and maintenance investment spending streams could be optimized. By 2019, with AM processes becoming more repeatable and mature, EDTI decided to formalize their asset risk-based framework as part of an asset analytics accelerator (A^3) software platform, designed to manage the computation of individual asset analytics, generate long-term investment plans as well as corresponding reliability forecasts. At the same time, the utility has also embarked on the development of a centralized data lake, which harmonizes data across EDTI's many enterprise systems, ensuring that all EDTI employees are leveraging the same consistent set of information for decision-making purposes. Each of EDTI's enterprise systems, including the A^3, as well as the CMMS, ERP, and GIS systems, all leverage the same information from within this data lake to support the AM practice.

EDTI has achieved several benefits as they have introduced and enhanced their AM practice, including the following:

- Establishing the capability to compare and contrast various decisions by assessing the outcomes (spending, risk, reliability).
- Enhanced quality of information as provided within their regulatory reporting process, providing objective, data-driven outputs, and business case results to support their investment plans.
- With the introduction of the data lake, EDTI expects to continue to see improvements to both data quality as well as data accessibility.
- EDTI continues to expand upon their AM practice through the introduction of Enterprise Risk Management (ERM) and dynamic monitoring programs to generate operational alerts for major substation equipment.
- EDTI has achieved a 15% sustained improvement in reliability since 2014, including a 43% reduction in defective equipment-related outages, achieved within the first two years of introducing their asset risk-based framework.

There are several similarities between EDTI's AM journey and YEC's journey, including the following:

- YEC's AM practice currently allows for age and condition-based analytics to be generated for individual assets, while also generating a current-state assessment of the system to assess assets past their typical useful life as well as assets in poor and very poor condition.
- YEC's EAM platform provides similar functionality to EDTI's A^3 and CMMS platforms, including the production of asset-level analytics (age, condition, and risk), long-term and short-term investment planning scenarios and outcomes.
- YEC's EAM also supports the centralization of all AM-related data, such that data accessibility and consistency are enhanced.
- In general, YEC's AM practice allows the utility to produce objective, data-driven outputs to support capital and maintenance planning and decision-making.

B1.2 Toronto Hydro-Electric System Limited (THESL)

THESL began its journey in the mid-2000s in transitioning from subjective and engineering-driven decision-making to economically-driven, risk-based decision-making, leveraging age and condition analytics for each of its assets.

As a first step, the organization began introducing system and feeder-level reliability indicators as well as programs such as Worst Performing Feeders (WPF), designed to track specific portions of its system where an unaccepted number of sustained interruptions were occurring. Beginning in 2007, the utility introduced the Feeder Investment Model (FIM), designed to establish asset-level analytics on individual assets, leveraging nameplate information and connectivity data as retrieved from the utilities' GIS, along with condition information as collected by in-field maintenance processes to quantify the risk of failure and determine the economic end-of-life of each asset. Results from the FIM were leveraged to generate a current-state assessment of asset performance, including percentages of assets past typical useful life, assets in poor and very poor condition, as well as assets beyond their economic end-of-life criteria—very similar to the activities undertaken by EDTI.

THESL began leveraging results as produced by the FIM and their broader AM practice as part of their regulatory reporting procedures, beginning in 2008 with their 10-year investment plan. By 2012, THESL was leveraging their AM practice to develop formal business cases for individual capital investment programs and projects, and by comparing the capital investment requirements against the quantified risk of asset failures should no action be undertaken. As these new forms of analytics were introduced, THESL also embarked on efforts to further automate the collection of data necessary to perform the analysis, as well as the analysis itself. THESL also introduced their own Reliability Forecasting model to better illustrate the outcomes of its investment plans from a reliability performance perspective. As THESL's AM practice, along with underlying data and processes have matured and become repeatable over time, the utility is now moving forward with further integration of their analytics into established enterprise systems, including CMMS and AIP platforms.

Figure B2 illustrates THESL's broader AM Process, and how decision-making analytics are leveraged to establish the asset needs and requirements, develop the long-term portfolio plan, develop the short-term scope and capital projects, and create performance measures to manage the execution of the plan over time.

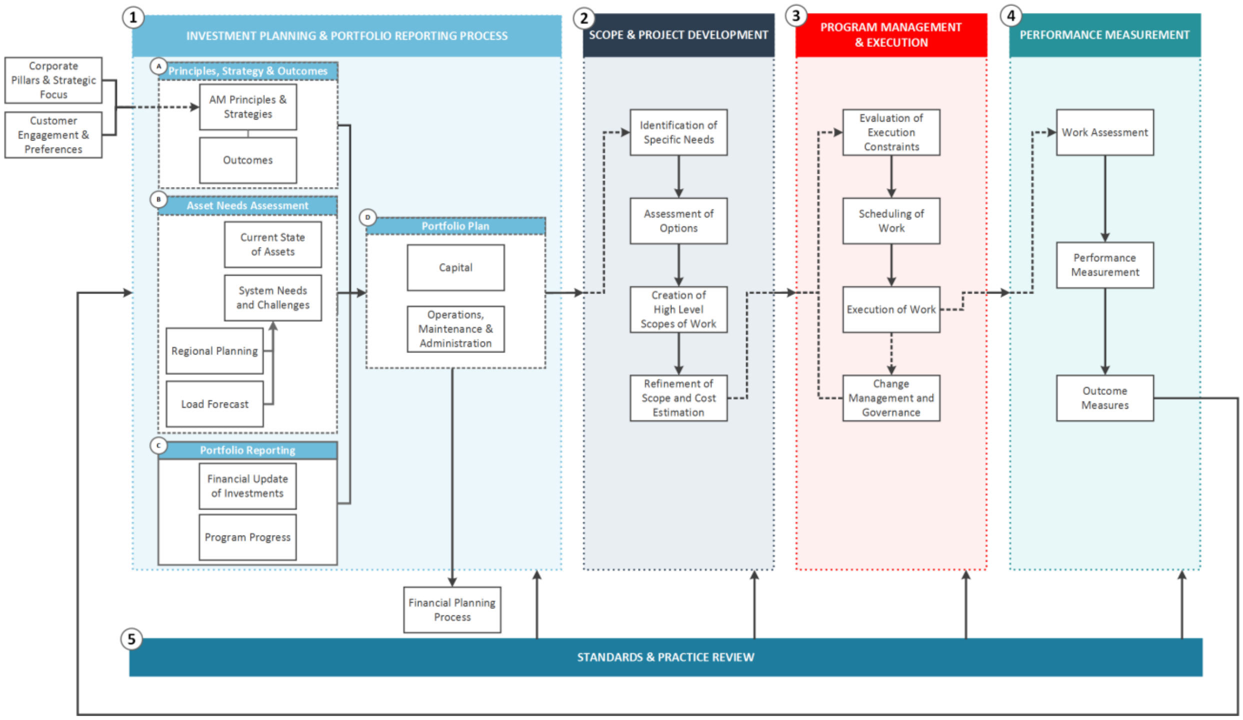

Figure B2: Toronto Hydro's AM Process [[6]]

THESL has achieved several benefits as they have introduced and enhanced their AM practice, including the following:

- Transitioning from a subjective, engineering-driven decision-making approach to an objective, data-driven, quantified, and prudent decision-making approach.
- Establishing the capability to generate a current-state snapshot of system performance, taking into consideration age, condition, and risk.
- Establishing the capability to provide outcomes to capital and maintenance investment programs concerning system reliability and risk.
- Establishing the capability to deliver a quantified business case for each capital investment program.

There are several similarities between THESL's AM journey and YEC's journey, including the following:

- YEC's AM practice is helping them in transitioning from subjective, engineering-driven decisions to objective, data-driven decisions.
- YEC's AM practice currently allows for age and condition-based analytics to be generated for individual assets, while also generating a current-state assessment of the system to assess assets past their typical useful life, as well as assets in poor and very poor condition.

[6] "Asset Management Process Overview," EB-2018-0165 Application, Toronto Hydro-Electric System Limited, 2018.

- YEC's AM practice is helping them in defining consistent business cases to help justify capital and maintenance activities.

B1.3 ENMAX Power Corporation (EPC)

EPC recently began a new journey to advance their current suite of AM analytics, moving away from the labour-intensive analytics methodology that they had in place, and towards a risk-based modelling approach that would allow for budget optimization, objective data-driven decision-making, and would ultimately ensure that their selected investments are maximizing benefits to customers while enhancing usage of existing assets. These advancements would ultimately allow the utility to enhance its regulatory reporting capabilities by providing clear outcomes of its plans and decisions.

The organization first introduced foundational documents and processes to manage the AM practice, including an AM Policy and Strategic Asset Management Plans. These were followed by the development of Asset Management Plans (AMPs) for major asset classes. These AMPs helped define the planning parameters and objectives for each asset class, including establishing a current-state assessment of the asset class, leveraging available asset data including age and condition-based demographics, defining investment drivers, documenting all intervention policies and practices to manage end-of-life and high-risk assets, and establishing the expected levels of service that the utility wished to achieve over time.

In 2020, the utility began leveraging its underlying data used to support risk modelling, including failure curves, health indices, criticality and risk and established an analytics roadmap to mitigate key gaps and enhance overall decision-making through the introduction of an A^3 platform. This platform needed to intake the most up-to-date information from a variety of enterprise systems and frameworks across EPC, including their CMMS, load-flow software, OMS, AIP, and health index frameworks. Key elements to be supported within their A^3 platform included:

- Health index results leveraging in-field maintenance and nameplate data.
- Survival analytics leveraging historical outage information.
- Failure consequence analytics, accounting for EPC's connectivity model and the impacts of failure within the system, including financial, customer, environmental and collateral damage-related impacts.
- "Bottom-up" reliability forecasts, leveraging the survival analytics results.
- Business intelligence reporting capabilities such that results could be easily integrated into regulatory reporting and planning procedures.

The A^3 platform has allowed EPC to develop long-term planning scenarios at the system and feeder levels respectively. For each planning scenario, EPC can also view the impacts, including potential risks to the utility. More critically, the platform has allowed EPC to develop more enhanced analytics to support the replacement of underground cables, which remain a high-risk, high-value asset of replacement within the system.

EPC has achieved several benefits as they have introduced and enhanced its AM practice, including the following:

- **Customer Value:** The organization can now better prioritize assets for replacement while predicting the customer outage minutes that are saved. By determining the economic life of the asset based on the balance of risk and cost, the utility can determine the optimal replacement time resulting in the lowest cost to the ratepayer.

- **Data Quality:** The introduction of the platform has allowed EPC to more effectively prioritize data quality improvements, as there is an enhanced understanding of how specific data inputs are leveraged within the analysis to produce the planning outputs.
- **Enhanced Productivity:** The A^3 platform has allowed EPC to produce risk-based analytics in a turn-key manner, without the need for extensive data manipulation or formatting.
- **Strategy and Process Improvements:** Moving forward, results from the A^3 platform will be leveraged to inform future AMPs, which also helps in streamlining the overall capital planning schedule.
- **Enhanced Risk Analysis:** The introduction of the A^3 platform has ultimately allowed EPC to leverage risk in more planning applications, including establishing risk mitigation plans, risk tolerance levels, and risk spending efficiency levels to further enhance asset strategies.

There are several similarities between EPC's AM journey and YEC's journey, including the following:

- YEC has established foundational documents and processes to manage the AM practice, including an AM Policy, Strategic Asset Management Plans, as well as Asset Management Plans (AMPs) for key asset classes.
- YEC has introduced new analytics, including Asset Criticality Ranking (ACR), that takes into consideration the customer impacts as part of the prioritization approach.
- In the same manner as EPC, the introduction and further implementation of the EAM within YEC will result in strategy and process improvements, enhanced risk analysis, enhanced data quality, as well as enhanced productivity across the organization.

ATTACHMENT 5.3A-1.1:
PAMMS INITIAL 2018-2019 WORK

ATTACHMENT 5.3A-1.1: PAMMS INITIAL 2018-2019 WORK

1.0 5 YEAR VISION (2018-2022)

The 5-year vision for YEC's Asset Management program included the following key goals/deliverables:

a) Implementation of a new Enterprise Asset Management (EAM) IT system, as a key element of an enhanced Asset Management program. This EAM will replace and enhance the functionality of YEC's existing CMMS system. As noted above, the procurement and implementation of the EAM was executed under a separate capital project;

b) Implementation of risk and condition based management for all key assets over their complete life cycle, integrating maintenance and capital work;

c) Implementation of a comprehensive process for identification and management of spare parts;

d) Definition and initial reporting of Health Indices for all key assets; and

e) Development of a centralized Asset Registry.

The initial implementation project was for a 5-year plan and included a project budget of $5.48M. The first two years of the Asset Management Framework project were approved in March 2018 at $2.08M for 2018 and 2019. The project was to be reassessed at the end of 2019, and another request for funding to complete the project submitted at the December - 2019 BOD meeting.

The project plan and budget developed in 2018 for the Asset Management Framework project, with the support of the Asset Management Consultant, leaned heavily on consulting resources for both guidance and expertise in developing an asset management system appropriate to YEC, and to avoid placing additional pressure on internal resources which were already stretched.

2.0 PROJECTED BENEFITS

The project benefits named at project inception included the following:

a) Long Term Capital Planning: the proposed Asset Management program will deliver comprehensive data and supporting analysis on the condition of YEC's key assets, which will be used to support and justify YEC's long term Sustaining Capital plans and associated long term financing requirements. This data is critical for the evaluation of YEC's future capital needs by the YEC Board, Shareholder and Yukon Government.

b) Regulatory Approval: Information on the condition of key assets can be used to show the prudency of YEC's Sustaining Capital investments to the Yukon Utilities Board (YUB).

c) Operational Efficiencies: Utilities that have implemented Asset Management programs based on the ISO 55000X standard have achieved operational savings in the range of 15-25%. While Management has not quantified the expected cost savings that will result from implementation of the proposed Asset Management framework, savings are expected to arise from of the following:

   i. Efficiency improvements in the planning and execution of maintenance work;

   ii. Capital efficiency improvements through the prioritization of investments according to asset criticality, condition and risk;

   iii. Optimization of relative expenditures on operating costs (e.g., maintenance) vs capital expenditures (asset refurbishment or replacement);

   iv. Efficiency improvements from improved availability and management of documentation and data related to assets.

The EAM system is designed to report on KPI's based on data captured in the EAM system through work management, inventory management, and asset management. Operational KPI's are designed to be used by management and O&M personnel to monitor the performance of the PAMMS and the EAM system. The information provided by the KPI's is a tool used to determine if changes need to be made to improve performance and to measure any changes made to work being performed by O&M. measuring performance through KPI's is an important component of the continuous improvement cycle (Plan-Do-Check-Act), and are the means through which changes (improvements) can be measured. The EAM system itself is a building block for the ability to measure KPI's – implementing work management process in EAM enables the capture of data which is used to calculate the KPI's which report of the process' effectiveness, as well as the impact of changes to related processes.

3.0 PROJECT BOUNDARIES

The scope of the Asset Management framework is focused on YEC's critical assets and equipment.

Other equipment and assets could be included in the future as the program evolves but were not included in the initial scope of the project. The assets included as part of the initial project included:

a) Generation stations (includes all hydro and thermal units);

b) Dams for generation stations;

c) Water control structures;

d) Transmission lines;

e) Substation equipment (transformers, circuit breakers, foundations, protection & control,

f) RTU, but not structures);

g) Distribution lines (above 600V) up to, but not including the customer meter; and

h) Pole- and pad-mounted transformers

The following assets were not included in this scope of work, but may be included in later phases of the program, or upon request:

a) Vehicles;

b) Metering systems (Customer service entrance);

c) Distribution low voltage systems (and other run to failure distribution equipment like switches, fuses, etc.);

d) Communications systems and software;

e) Buildings, office equipment;

f) Specialized tools;

g) Test equipment;

h) SCADA equipment;

i) Computer systems and software;

j) Intellectual property; and

k) Lifting devices.

4.0 WORK COMPLETED, 2018-2019

The work on the Asset Management program in 2018 and 2019 includes the following:1

a) Executive and management engagement workshops

b) Future Vision and Work Plan Development

c) Development of an Asset Management policy

d) Development of Management of Change (MOC) Policy and process

e) Development of a SAMP (Strategic Asset Management Plan), and

f) Asset Data Collection for all hydro plant equipment and Asset Register development

g) Development of comprehensive maintenance plans for all hydro plants

h) Development and recruitment of a maintenance planner/scheduler position.

i) Started Asset Hierarchy and Naming Convention procedure (completed 2020)

j) Asset Management Plans Created for:

   i. Transmission Lines (69-138kV)

   ii. MH0 Hydro Plant (Mayo Hydro)

   iii. MBH0 Hydro Plant (Mayo-B)

   iv. WH4 Hydro Plant (Whitehorse)

   v. WH0 Hydro Plant (Whitehorse)

vi. AH0 Hydro Plant (Aishihik)

vii. Power Transformers (69-138kV)

k) Asset Health scoring of major equipment included in 2019 AMP's.

l) A Risk assessment for Transformer T9 at WH4, and risk-cost study.

m) Project Management and Contractor Management

n) exploratory discussions into the following were triggered, however work did not progress beyond the first stages.

o) Implementation of a document management system (EDMS).

i. Resources were assigned to EAM project, and undertaking an EDMS project was considered too much added change for YEC to undertake at the same time.

p) Expanding parts management in support of O&M.

i. Exploratory discussions into future state and Roles and Responsibilities, process, and systems. Parts management was deferred until later as progress was dependant on internal capacity and work management tools and capabilities in the future EAM solution.

q) A Review of the direction of the first two years of work, and the development of the PAMMS project (see below).

5.0 EXPENDITURE REVIEW, 2018-2019

Expenditure	Description	Cost ($000)
Strategy and Planning	Future state workshops, plan development, policy development, SAMP development, Management of Change.	$308
MRO Materials Management Roadmap	Workshops, policy development, process development, R&R development, future vision.	$130
C18420 Whole Life Cost Justification	Transformer T9 Risk-Cost Analysis.	$4
C18430 Lifecycle Delivery	Development of AMP's for all Hydro Plants (x5), Transmission, and Power Transformers.	$491
C18431 Maintenance Plans (part of Lifecycle Delivery)	Documentation of current state and recommended future state maintenance plans for hydro plants and auxiliary equipment, include contractor collection of asset data.	$436
Asset Health Index	Internal labor, manual collection of AHI for Hydro equipment.	$13
Asset Information	Internal labor to support collection of hydro asset register at 5 plants.	$65
Project Management, Contractor Management, Project Admin	Internal project lead and Contract PM Combined. Plan development, estimate development. Project tracking and execution, reporting, etc.	$341
Total 2018-2019		**$1,788**

ATTACHMENT 5.3A-1.2:
PAMMS SUBSEQUENT 2020-2023 WORK

ATTACHMENT 5.3A-1.2: PAMMS SUBSEQUENT 2020-2023 WORK

1.0 KEY 2020-2022 PROJECT DELIVERABLES INCLUDE:

- Implementation of a PAMMS framework and governance model, process, and procedure.
- Completion of the asset hierarchy and naming convention for the EAM system
- Data collection for the Enterprise Asset Management (EAM) system
- Further development of Maintenance Manuals (Maintenance plans and instructions)
- Finalization of the Asset Management Plans (AMPs) which include YEC's protection and control, diesel, substation, dam and distribution assets
- Maintenance Repair and Operations (MRO) Material Support
- Organizational change management

2.0 2020-2023 COMPLETED WORK

Work completed on the PAMMS / Asset Management project in the period 2020-2023 includes the following.

1. Develop and document Asset hierarchy and naming standard.
2. Asset Data collection and loading to support EAM
3. Develop and recommend KPI procedure
4. Document EAM governance Roles and Responsibilities
5. Formalize and document Asset Criticality Ranking process
6. Formalize and document Asset Health Index Scoring process.
7. Develop and document Capital Project turnover requirements and process.

8. Update of MOC (Management of Change) process to align with EAM capabilities
9. Document procedure for maintenance job planning and work scheduling
10. Develop and document process for MRO and consumables parts management in alignment with EAM
11. Develop roadmap and case for MRO parts management expansion.
12. AMP for Stationary Diesel Generators and diesel generating plants
13. Develop and document maintenance strategy for diesel plant equipment and inspection strategy for diesel engines.
14. Draft of Project Management Guide for internal PM Process improvement.
15. Asset Health Report for Diesel Generation plants and equipment.
16. Develop and implement improvements to capital planning and project ranking process
17. Develop long range Capital Forecast framework.
18. Project Management, Contractor Management, Project Admin

Work in Progress at Q3 2023 includes the following, to be completed by year end 2023 includes.

1. Update capital planning handbook with long range capital planning framework.
2. SAMP and Policy Update, Roadmap check-in
3. Substation Asset Hierarchy Validate and Update
4. Dam and Spillway AMP, including AHI report
5. Distribution Equipment AMP, including AHI report
6. Substation Equipment AMP, including AHI report

3.0 PROJECT FINANCIALS 2020-2023 (FORECAST TO PROJECT COMPLETION)

Expenditure	Description	Cost
Develop and document Asset hierarchy and naming standard		$112,110
Asset Data collection and loading to support EAM	Hydro, Diesel, LNG, and Substation	$344,755
PAMMS Procedure development	Includes KPI development, EAM Governance Roles & Responsibilities, Capital Turnover requirements, and work management, planning, and scheduling process development.	$502,818
MRO related process development, expansion planning	Includes development of process for EAM, future state warehousing, stocking decision, and restocking process, planning for central stores to support generation equipment.	$627,121
Develop and document AHI Framework	Includes AHI framework, ranking scheme for equipment, process for implementing in EAM.	$157,861
Develop and document ACR Scoring Framework	Includes AHI framework, ranking scheme, process for implementing in EAM.	$100,000
MOC (Management of Change) process development	Process workshops, align with EAM capabilities; develop training materials for staff.	$97,500
Asset Management Plans	• Protection and Control Systems • Diesel Plant and Generator. • Dam and Spillway, all sites • Substation Equipment, 5 asset classes, all sites • HV Breakers • Distribution assets • Includes documentation of maintenance plans, health scoring as possible with reasonably available data	$984,641
Draft of Project Management Guide for internal PM Process improvement	Internal labor, PM Guide development.	$5,000
Develop & implement improvements to	Capital project evaluation, ranking, and capital plan	$64,000

Expenditure	Description	Cost
capital planning and project ranking process	development procedures.	
Develop long range Capital Forecast framework.	Long range capital planning and data requirements.	$90,000
SAMP and Policy Update, Roadmap check-in	SAMP update with current state; Policy update.	$165,020
Project Management, Contractor Management, Project Admin	Internal, external labor.	$427,367
Total 2020 through 2023 (Estimate at Completion)		**$3,678,200**
Total 2018-2019		**$1,788,000**
Net		**$5,466,200**

APPENDIX 5.3B
INTANGIBLE ASSETS >$100,000 AND <$1 MILLION ADDED TO RATE BASE

APPENDIX 5.3B: INTANGIBLE ASSETS >$100,000 AND <$1 MILLION ADDED TO RATE BASE

Appendix 5.3B summarizes intangible assets cost projects over $100,000 but less than $1 million that will be added to rate base in the test years. Details on project costs are summarized in Tables 5.3 to 5.6.

Rate base additions from 2021 to 2024 in each intangible assets cost activity totaling between $100,000 and $1 million that impact 2024 rate base are summarized below (total rate base impact in 2024 test year of approximately $0.766 million, excluding reductions due to amortization, reflecting $0.147 million additions in 2022, $0.368 million additions in 2023, and $0.250 million additions in 2024). These rate base additions relate to the following projects:

- EAM Enhancements Review ($0.147 million in 2022);
- Network Software Traffic Shaping ($0.250 million in 2023);
- CIS Replacement ($0.118 million in 2023);
- P&C Central Event Data Collection System ($0.150 million in 2024); and
- SharePoint Upgrades ($0.100 million in 2024).

EAM Enhancements Review	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
		$0.147 million		

Overview

After the first year of in-service operation, the Enterprise Asset Management (EAM) software required the following work:

- Critical fixes to integrations uncovered during use in the first year;
- Functionality enhancements not covered under support agreements;
- EAM software update;
- Data updates;
- Development and implementation of asset health index framework.

Analysis and Conclusions

If regular software updates are not completed, critical security patches are not able to be applied without customization at a significant cost. If these enhancements were not completed, YEC would not be able to realize the full potential of the system and would find it challenging to obtain vendor support.

Network Software Traffic Shaping	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.250 million	

Overview

This project will upgrade YEC network routing software.

Analysis and Conclusions

The YEC network routing software is currently at end of life, no longer supported by the vendor and needs to be upgraded. If it is not upgraded in 2023, the only alternative will be a complete replacement at a significantly higher cost. Further, the successful integration of various capital projects on the system (including BESS and Haeckel Hill wind IPP) require this work to be completed.

CIS Replacement	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
			$0.118 million	

Overview

The project will replace the current billing system with Oracle CCS.

Analysis and Conclusions

Yukon Energy's current billing system (ATCO CIS) has reached end-of-life. ATCO, YEC's billing services supplier will be replacing CIS with Oracle CCS in 2023. Purchasing and managing a YEC-specific billing system would be significantly more expensive and would duplicate billing system costs to ratepayers. Keeping the old system is not an option as ATCO will no longer support the CIS system after the Oracle CCS solution is implemented. There is no alternative but to proceed with this work.

P&C Central Event Data Collection System	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
				$0.150 million

Overview

This project will install SEL Blueframe, a central outage analysis tool that provides automatic collection of protection relay sequence of events (SOE) records and oscillography data.

Analysis and Conclusion

Following certain outages, operations personnel must retrieve information and records locally from the affected substation or generating station. This information includes protection relay SEO records and oscillography data. This consumes work hours and the long distances driven can present a health & safety risk, especially in winter.

Blueframe will be setup to communicate with all SCADA RTACs in substations and generating stations to automatically retrieve event data after system faults and abnormalities. process improvement will eliminate the travel time required for operations personnel and will also speed up outage investigations and improve overall system reliability.

SharePoint Upgrades	**2021 Actual**	**2022 Actual**	**2023 Forecast**	**2024 Forecast**
				$0.100 million

Overview

This project will upgrade both versions of Sharepoint that YEC uses to SharePoint 2019, the latest stable version that is adequately supported.

Analysis and Conclusions

Yukon Energy uses Microsoft SharePoint for general business activities (currently 2016 version) as well as SCADA data logging (2016 version). SharePoint 2013 lost mainstream support in 2018 and only critical security patches have been applied since then. SharePoint 2016 lost support in mid 2021 and as a result, we are not able to leverage new technologies and interfaces on this platform.

This project will upgrade both versions to SharePoint 2019. The old SharePoint instances would be decommissioned and our existing licences can be used with the new version, resulting in no additional O&M costs.

Maintaining the status quo is not viable as it exposes YEC to security threats and risks the loss of basic functionality. Migrating everything to SharePoint Online, a cloud based solution, was considered; however, any minimal costs savings would be offset by the work required to assess the impacts and risks related to this solution.

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 December 2018 (OIC 2018/220) provides that material rate design changes that would result in rebalancing of rates between different customer classes cannot be undertaken at this time. The remaining outstanding directives in Order 2010-13 will be addressed in the next joint cost of service and rate design application. This includes directives #1 to #12 and #19 (as summarized in Tab 6 of the 2012/13 GRA filing).

The balance of the information reviewed in Tab 6 relates to outstanding directives since the submission of the 2021 General Rate Application (GRA). Attention is directed below on directives relating to revenue requirement matters – Board recommendations in reports to the Minister on specific projects (e.g., Atlin EPA or the Battery proceeding) are addressed as relevant in any review of these projects in the 2023/2024 GRA Application.

6.1 BOARD ORDERS 2022-03, 2022-06, AND 2022-07 – YUKON ENERGY 2021 GENERAL RATE APPLICATION & RELATED COMPLIANCE FILINGS

On November 20, 2020, Yukon Energy Corporation filed an application with the YUB, pursuant to the *Public Utilities Act* (PUA) and OIC 1995/90 for approval of its forecast revenue requirements for the 2021 test year. The 2021 test year revenue requirement was approved subject to Board ordered adjustments pursuant to directions provided in Order 2022-03. Yukon Energy filed its Compliance Filing regarding Order 2022-03 with the Board on April 14, 2022. Order 2022-07 was provided on July 12, 2022 noting that the Board approved YEC's April 14, 2022 submission as filed, noting "YEC's 2021 GRA compliance filing reflects the directions provided in Board Order 2022-03. YEC's requested changes to YEC's rate riders, Rate Schedule 39 Industrial Primary Fixed Charge, RS39 Fixed Charge true-up, and Low Water Reserve Fund (LWRF) Term Sheet are also approved, effective August 1, 2022" (Appendix A, paragraph 18). Order 2022-07 also directed that YEC and AEY provide a joint proposal to the Board on how to incorporate their riders into base rates within 180 days of the issuance of the Order (Appendix A, paragraph 19).

Order 2022-03 resulted in a number of specific Board directions. Most directives were incorporated into the Compliance Filing. Yukon Energy's responses to each of the remaining directives are outlined below, where applicable.

6.1.1 Directives related to Sales and Generation

Wholesale Forecast (paragraph 39)

> ***"The Board directs that in future GRA submissions, YEC shall provide the Board with details on discussions with AEY to align their wholesale sales forecasts".***

See Tab 2, Section 2.2.1 for a description of discussions with AEY to align wholesale sales forecasts.

Generation Forecast (paragraph 68)

> ***"For the next GRA, the Board directs YEC to provide details on how it calculates the line losses".***

See Tab 2, Section 2.3 for a description of how line losses were forecast in the application.

Peak Demand Forecast (paragraph 72)

> ***In Board Order 2018-10, the Board encouraged YEC to communicate closely with all parties (for example, AEY, customers, developers, mining operations) to ensure that it is able to forecast peak demand as accurately as possible to ensure increased peak loads may be met. The Board observes that peak loads are growing and directs YEC***

> ***in the next GRA to provide a detailed description of the steps it took in complying with Board Order 2018-10 including detailing the dates of meetings with other parties and summarizing the outcomes of those meetings and of the manner in which those outcomes are reflected in the forecast peak demand.***

Tab 2, Section 2.4 provides a description of the method used by YEC to develop the peak demand forecast for the test years, focusing on the non-industrial peak demand relevant for YEC N-1 dependable capacity planning. In summary, forecasting near term test year peak load forecasts of necessity relies upon available information and modelling – when assessing longer term forecasts for resource planning purposes (and when justifying current capital expenditures to meet future peak loads), YEC also reviews Yukon government and other plans that may affect future peak loads.

6.1.2 Directives related to Revenue Requirement

Production Expense (paragraph 115)

> ***"...the Board directs YEC to provide a specific business case going forward for the diesel units (rental, lease and own/resale), other alternatives to rentals and stronger emphasis to least-cost options, the rationale for the options and the timing to implement such options. Of particular interest to assist in evaluating comparisons of Levelized Costs of Capacity would be a sensitivity analysis that includes delays in planned permanent renewable capacity projects and higher-than-forecast peak demand growth over the next 10 years. The Board directs YEC to provide a business case that conforms with these business case criteria in its next GRA".***

See Section 3.3.2 which addresses diesel rental costs, Appendix 3.1 which address the above Board directive, and Appendix 5.1A which includes the business case for expansion of thermal infrastructure.

Insurance Costs and RFID Account (paragraph 126)

> ***"The Board directs YEC to provide evidence of its continued efforts to achieve the appropriate amount of insurance at the most reasonable cost available at the time of its next GRA".***

See Tab 3, Section 3.3.6 which summarizes and explains the basis for insurance cost increase for 2023 and 2024.

Depreciation Expense (paragraph 164)

> ***"YEC is directed to continue to rely on the currently approved 60-R3 for Account 1635-300 and to provide clarification of the use of wood preservative or treatment process no later than the time of YEC's next depreciation study".***

It is noted that Appendix A of Order 2022-03 has a typographical error in paragraph 164 – as the paragraph references "the currently approved 60-R3 for Account 1635-300" which is incorrect. The correct reference is 65-R3 (which corresponds to the reference in Appendix 1 of Board Order 2022-03). Yukon Energy has applied 65-R3 to Account 1635-300 and 1640-300 (consistent with Appendix 1).

A new depreciation study has not been undertaken; Yukon Energy will provide the above-noted clarification at the time the next depreciation study is undertaken.

6.1.3 Directives related to Capital Projects

In Order 2022-03 the YUB provided specific remarks in paragraphs 9-13 of Appendix A to the Board Order noting that "the Board makes several statements critical of YEC's consistent failure to present an adequate business case in support of the revenue requirement it is seeking in the current GRA." (para 9) The Board reviewed the criteria of reasonableness or prudence, noting that these criteria "cannot be applied except in the context of relationships with other factors" and that "This is a principle underlying the Board's repeatedly stated expectation that the significant projects it is called on to assess must be supported by an adequate business case." (para 10). The Board highlighted prior guidance that "YEC provide a detailed comparison of alternatives…including the pros, cons, capital costs, operating costs and timeline to in service and justification for its preferred option." (para 12) The Board noted "Without a proper business case satisfying the criteria just mentioned, the Board is often left with an incomplete presentation that makes it difficult, if not impossible, to determine whether YEC, as the project proponent, has acted prudently or reasonably." (para 13) The Board concluded these remarks as follows: "If this practice of failing to provide adequate business case information and analysis continues, YEC may find itself at risk of the project costs being denied, as well as reduction of the costs claimed in the proceeding" (para 13).

Yukon Energy has worked to apply the above guidance provided by the Board in Order 2022-03 in preparing the Tab 5 business cases provided for Major projects >$1 million that are forecast to be completed and in service during the test years and added to rate base.

General Matters (paragraph 242)

> ***"The Board directs YEC to present cost breakdowns for its capital projects in a uniform manner in future GRA proceedings. The Board further directs YEC to provide schedules for all capital projects in the CWIP continuity format – the template for which was provided in information request YUB-YEC-2-16 in future GRA proceedings. In order to ensure a fair and efficient process for future GRAs, if YEC does not comply with this direction, the Board may request YEC to update and refile its application or may deny the application".***

The tables included in Tab 5 have been updated to follow the continuity format outlined in the above direction.

Transmission Line Refurbishment Projects (paragraph 265)

> ***"Costs for the second phase will only be added to the rate base once the second phase is complete and YEC provides the actual capital spending amount incurred in the next GRA".***

See Tab 5, Appendix 5.1A and Tables 5.2 to 5.6. YEC is seeking to include these costs in rate base as part of this GRA.

P125 Headgate Replacement Project (paragraph 270)

> ***"Costs for this project will only be added to rate base once the project is complete and YEC provides the actual capital spending amount incurred in the next GRA".***

The project has been completed and YEC is seeking to include these costs in rate base at this time. See Tab 5, Table 5.2; and Appendix 5.1A.

Capital Costs: Projects between $100,000 and $1 Million (paragraph 289)

> ***"The Board directs that YEC include the updated costs, excluding the WH4 Ventilation Project, for any projects that have been completed prior to or during the 2021 test year period. Costs for these projects will only be added to rate base once YEC provides the actual capital spending amount in the next GRA and demonstrates that the costs were prudently incurred".***

See final costs for 2021 completed projects in Tab 5, Table 5.2; and completed projects listed in Tab 5, Tables 5-2 to 5.6; project summaries where relevant are provided in Appendix 5.1B.

Demand Side Management (DSM) (paragraph 310)

> ***"The Board is sympathetic with UCG's argument that it was difficult to follow numerous DSM cost adjustments and updates and directs YEC in future GRAs to provide any DSM cost updates and variance explanations at the time of filing its rebuttal evidence".***

Relevant updates and variance explanations, if required, will be provided at the time YEC files its rebuttal evidence.

Deferred Costs: Projects between $100,000 and $1 Million (paragraph 322 & 323)

> ***"The Board is not prepared to approve the costs for the Atlin Hydro EPA Preparation project because YEC currently has an application for review of the Atlin EPA before the Board. The Board finds it necessary to complete the regulatory process for the Atlin EPA before it can assess the prudence of costs for preparation work".***

Please see Tab 5, Appendix 5.2B – the only Atlin Hydro EPA costs proposed for inclusion in 2023/24 test year revenue requirements relate to the completed hearing process to review the Atlin Hydro EPA.

> ***"To ensure that actual capital spending to the end of 2021 is accurately reflected in rate base, the Board directs YEC to include the updated costs for any projects that have been completed prior to or during the 2021 test year period. Costs for these projects will only be added to rate base once YEC provides the actual capital spending amount in the next GRA".***

See final costs for 2021 completed projects in Tab 5, Tables 5.2 to 5.6; see also Appendix 5.2B for relevant projects.

6.1.4 Directives related to additional matters to the GRA

LWRF Annual Reports (paragraph 347)

> ***"On a go-forward basis, the Board directs YEC to submit its annual LWRF report to the Board within 60 days of the close of the year. YEC shall reflect this direction in its revised LWRF term sheet to be filed in the compliance filing to this Board Order".***

On July 29, 2022, Yukon Energy Corporation (YEC) filed correspondence with the Yukon Utilities Board (Board) entitled "2021 Low Water Reserve Fund Report and Energy Reconciliation Adjustment Filing". The submission was pursuant to YEC's LWRF Term Sheet as approved in Board Order 2022-07. On January 20, 2023, the Board issued Board Order 2023-03 which considered the YEC submission as an application to be decided via written proceeding, pending Ministerial approval for such proceeding. Board Order 2023-07 approved the LWRF Report and ERA filing as submitted by YEC.

On April 13, 2023, Yukon Energy Corporation (YEC) filed correspondence with the Yukon Utilities Board (Board) titled "2022 Low Water Reserve Fund Report and Energy Reconciliation Adjustment Filing". The submission was pursuant to YEC's LWRF Term Sheet as approved in Board Order 2022-07. On April 27, 2023, the Board issued Board Order 2023-09 which considered the YEC submission as an application to be decided by way of a written proceeding, pending Ministerial approval for such proceeding. Board Order 2023-11 approved the LWRF report and ERA adjustment filing as submitted by YEC.

6.2 BOARD ORDER 2022-07 AND 2023-08 ATCO ELECTRIC YUKON AND YUKON ENERGY CORPORATION RATE REBASING APPLICATION

Board Order 2022-07 approving YEC's compliance filing noted "the Board is concerned that customers may find the application of YEC's and AEY's riders to be confusing" and directed YEC and AEY to provide, a proposal on incorporating these riders into existing base rates within 180 days of issuance of the order.

On January 9, 2023, the utilities provided a joint submission to the YUB outlining four options that were compliant with government rate policy requirements, and providing a recommendation that would incorporate various rate riders into existing base rates. The four options were: status quo, rolling rate base adjustment riders into base rates, a limited scope Phase 2 GRA to roll base rate adjustment riders into base rates, and rolling base rate adjustment riders into base rates on the billing statement only. The fourth option was recommended by the utilities; and after a written proceeding, the Board in Order 2023-08 approved option 4 as presented by the utilities.

The Board noted that it did not agree with the response from the utilities regarding adding elements to the bill display (such as fixed and variable cost breakdown and providing more rider detail). The Board noted that the Utilities have not demonstrated that adding a few words to the description of a rider is cost prohibitive under the new billing system; but that this was a GRA issue. Similarly, the Board noted that stated intervenor concerns regarding billing estimates was also a GRA issue.[1]

To the extent that the above issues are raised by intervenors, they can be responded to by YEC as part of the GRA process.

6.3 BOARD ORDERS 2020-02, 2021-13, 2023-02 AND 2023-06

Cost awards were determined after the BESS project proceeding, the Yukon Energy 2021 GRA, and the THELP EPA proceeding. The Board provided the following directives related to hearing cost awards for each of these proceedings:

- BESS Project Proceeding (Order 2021-13 - Erratum):
  - "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 record these hearing-related costs in its Hearing Costs Reserve Account."
- 2021 GRA Cost Awards (Order 2023-02):
  - "Based on the reasons set out in Appendix A to this Board Order, the Board approves total costs of $903,487.96."
- THELP EPA Proceeding (Order 2023-06):
  - "Based on the reasons set out in Appendix A to this Board Order, the Board approves total costs of $385,637.77."

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).

[1] See Order 2023-08, Appendix A, paragraph 60-61.

1 **Table 6.1:**

2 **Cost Awards Order 2021-13, 2023-02 and Order 2023-06**

	Yukon Energy BESS Project [Order 2021-13]	Yukon Energy 2021 GRA Costs Awards [Order 2023-02]	Yukon Energy EPA-THELP Proceeding [Order 2023-06]
Yukon Energy	69,418	413,751	179,859
City of Whitehorse (CW)		55,579	
Utilities Consumers' Group (UCG)	14,411	18,271	
Nathaniel Yee		6,152	1,775
Yukon Government	135,690	409,735	204,003
Total	**219,519**	**903,488**	**385,638**

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TAB 7
FINANCIAL SCHEDULES

Yukon Energy Corporation 2023/24 GRA

August 31, 2023

Schedule Index

Yukon Energy Corporation Schedule 1
Computation of Rate Base August 31, 2023
($000s)

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	**Property, Plant and Equipment**						
2	Year end balance	S.3 L.4	728,282	691,598	735,254	813,146	877,301
	Deduct:						
3	Accumulated depreciation (note 1)	S.3 L.8	198,403	198,509	211,205	223,380	239,086
4	Construction-in-progress	S.3 L.12	40,572	3,808	33,638	81,644	100,578
5	Disallowed assets	S.3 L.11	12,152	14,406	13,688	676	632
6	Miscellaneous reserves	S.3 L.17	7,609	7,623	13,283	2,079	1,751
7	Total deductions		258,737	224,346	271,814	307,779	342,046
	Add:						
8	Deferred Costs and Intangible Assets (note 2)	S.3 L.83	44,229	42,173	43,681	55,630	65,696
9	Less: Deferred Costs and Intangibles in Progress	S.3 L.84	30,489	29,343	28,260	25,707	38,049
10	Total additions		13,739	12,829	15,421	29,923	27,647
	Net plant in Service						
11	Current year-end balance	S.3 L.86	483,285	480,081	478,861	535,291	562,902
12	Previous year-end balance		486,567	461,515	480,081	478,861	535,291
13	Mid-year balance		484,926	470,798	479,471	507,076	549,096
14	Working capital	S.2 L.8	7,092	6,925	7,581	8,267	8,576
15	**Gross Rate Base**		492,018	477,723	487,052	515,342	557,672
	Deduct:						
	Contributions for extensions (PP&E)						
16	Current year-end balance		254,348	235,303	247,475	259,283	264,183
17	Contributions in WIP		20,776	1,386	12,788	16,500	21,000
18	Current year-end balance in-service		233,571	233,918	234,687	242,783	243,183
19	Accumulated amortization of contributions		48,722	48,401	53,074	58,503	64,127
20	Net current year-end balance in-service		184,849	185,517	181,613	184,280	179,056
21	Previous year-end balance		180,255	168,025	185,517	181,613	184,280
22	Mid-year balance		182,552	176,771	183,565	182,947	181,668
23	**Net Rate Base**	S.5 L.1	309,466	300,951	303,487	332,396	376,004

Note 1: Including Reserve for Future Removal and Site Restoration

Note 2: Please see details in Schedule 3. In the 2021 GRA Regulatory Deferral Account balance was provided as a separate line item, now included with other deferral accounts with a detailed breakdown in Schedule 3. Balances are net of contributions.

Yukon Energy Corporation
Computation of Allowance for Working Capital
($000s)

Schedule 2
August 31, 2023

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Operating and maintenance	S.5 L.5	43,211	40,096	44,641	50,017	53,178
2	Taxes other than income	S.5 L.6	750	739	743	758	777
3	Non-allowable expenses	S.5 L.12	(120)	(117)	(121)	(120)	(120)
4	Cash operating expenses		43,841	40,718	45,263	50,655	53,835
5	27/365		3,243	3,012	3,348	3,747	3,982
6	Inventory (three year average)		4,014	4,156	4,464	4,683	4,817
7	GST Impact on working capital	S.2A L.11	(165)	(243)	(231)	(164)	(223)
8	Working capital	S.1 L.14	7,092	6,925	7,581	8,267	8,576

Yukon Energy Corporation
Effect of GST on Working Capital
($000s)

Schedule 2A
August 31, 2023

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Expenses subject to GST		96,059	50,415	69,788	118,093	110,174
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		4,803	2,521	3,489	5,905	5,509
4	Day Factor		14	14	14	14	14
5	Recoverable portion of GST impact		184	97	134	226	211
6	Revenue subject to GST		72,825	70,916	76,032	81,440	90,433
7	GST blended rate		5.00%	5.00%	5.00%	5.00%	5.00%
8	GST payable		3,641	3,546	3,802	4,072	4,522
9	Day factor		35	35	35	35	35
10	Payable portion of GST impact		349	340	365	390	434
11	Net impact of GST on working capital	S.2 L.7	(165)	(243)	(231)	(164)	(223)

Yukon Energy Corporation
Continuity Schedule of Property, Plant and Equipment, Deferred Costs and Intangible Assets
($000s)

Schedule 3
August 31, 2023

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
	Property, Plant and Equipment						
1	Balance at beginning of year		672,467	667,962	691,598	735,254	813,146
2	Net Increases to PPE (Table 5.1)		57,152	26,668	44,506	80,430	64,154
3	Retirements, disposals and adjustments		(1,337)	(3,032)	(850)	(2,538)	-
4	Balance at end of year	S.1 L.2	728,282	691,598	735,254	813,146	877,301
	Accumulated depreciation						
5	Balance at beginning of year		185,384	184,570	198,509	211,205	223,380
6	Depreciation expense	S.6 L.7	13,436	14,926	13,308	14,300	15,706
7	Retirements, disposals and adjustments		(417)	(987)	(613)	(2,125)	-
8	Balance at end of year	S.1 L.3	198,403	198,509	211,205	223,380	239,086
	Deductions from PP&E:						
9	Disallowed assets		13,192	15,166	15,166	1,152	1,152
10	Accum. Disallowed depreciation		(1,039)	(760)	(1,478)	(476)	(521)
11	Net Disallowed	S.1 L.5	12,152	14,406	13,688	676	632
12	Construction-in-progress	S.1 L.4	40,572	3,808	33,638	81,644	100,578
	Miscellaneous Reserves						
13	Fire Insurance Reserve		3,918	3,918	3,656	3,394	3,132
14	LWRF		2,744	2,744	9,895		
15	Reserve for Injuries and Damages		(1,843)	(1,777)	(2,997)	(3,281)	(3,347)
16	Reserve for Future Removal and Site Restoration		2,790	2,738	2,729	1,966	1,966
17	Total Miscellaneous Reserves	S.1 L.6	7,609	7,623	13,283	2,079	1,751
18	Total Deductions		60,333	25,837	60,609	84,399	102,960
19	Net Property, Plant and Equipment for Rate Base		469,545	467,251	463,440	505,368	535,255
	Add:						
20	Deferred study costs and Intangible assets (net of contributions)						
21	Feasibility Studies						
22	Opening balance		16,798	15,974	15,149	13,765	13,276
23	Additions		6,686	1,343	107	560	1,500
24	Amortization		(2,274)	(2,168)	(1,491)	(1,049)	(2,268)
25	Year-end balance		21,210	15,149	13,765	13,276	12,508
26	Feasibility Studies WIP			10,343	10,040	190	785
27	Relicensing						
28	Opening balance		11,882	12,485	13,884	17,089	27,135
29	Additions		1,745	1,738	3,544	10,866	6,110
30	Amortization		(339)	(339)	(339)	(820)	(928)
31	Year-end balance		13,288	13,884	17,089	27,135	32,318
32	Relicensing WIP			13,425	13,066	23,356	29,053
33	Dam Safety						
34	Opening balance		203	203	229	178	127
35	Additions		80	81	-	-	-
36	Amortization		(64)	(55)	(51)	(51)	(51)
37	Year-end balance		219	229	178	127	76
38	Dam Safety WIP			-	-	-	-
39	Vegetation Management Deferral						
40	Opening balance		1,329	1,329	1,108	886	665
41	Additions		-	-	-	-	-
42	Amortization		(222)	(222)	(222)	(222)	(222)
43	Year-end balance		1,108	1,108	886	665	443
44	Vegetation Management Deferral WIP			-	-	-	-

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
45	Intangibles						
46	Opening balance		5,076	4,952	5,012	4,582	9,840
47	Additions		1,095	926	359	5,976	4,830
48	Amortization		(729)	(866)	(789)	(718)	(1,281)
49	Year-end balance		5,442	5,012	4,582	9,840	13,389
50	Intangibles WIP			25	106	175	4,625
51	DSM						
52	Opening balance		876	720	623	736	1,857
53	Additions		120	(4)	208	1,250	1,160
54	Amortization		(161)	(93)	(94)	(130)	(255)
55	Year-end balance		835	623	736	1,857	2,762
56	DSM WIP			145	-	-	-
57	Hearing Reserve						
58	Opening balance		63	182	227	881	1,016
59	Additions		-	101	903	386	
60	Amortization		(55)	(55)	(250)	(250)	(250)
61	Year-end balance		8	227	881	1,016	766
62	Other Regulatory						
63	Opening balance		1,517	4,793	5,942	5,601	1,751
64	Additions		821	815	(390)	(3,909)	1,600
65	Amortization		(274)	278	(201)	(191)	(131)
66	Hearing Reserve Amortization tranfer		55	55	250	250	250
67	Year-end balance		2,119	5,942	5,601	1,751	3,470
68	Regulatory WIP			7,960	6,206	2,274	3,874
69	IPP Cost Deferral						
70	Opening balance			-	-	26	26
71	Additions			-	26	-	-
72	Amortization			-	-	-	-
73	Year-end balance		-	-	26	26	26
74	Defined Benefit Pension Deferral Account						
75	Opening balance			-	-	(62)	(62)
76	Additions			-	(62)	-	-
77	Amortization			-	-	-	-
78	Year-end balance		-	-	(62)	(62)	(62)
79	Total Deferred Costs and Intangible Assets						
80	Opening balance		37,744	40,638	42,173	43,681	55,630
81	Additions		10,547	5,000	4,695	15,129	15,200
82	Amortization		(4,063)	(3,465)	(3,187)	(3,180)	(5,134)
83	Year-end balance	S.1 L.8	44,229	42,173	43,681	55,630	65,696
84	Less: Deferred Costs and Intangible Assets in Progress	S.1 L.9	30,489	29,343	28,260	25,707	38,049
85	Total Net Deferred Costs and Intangible Assets for Rate Base		13,739	12,829	15,421	29,923	27,647
						P	
86	Total Net PP&E, Deferred Costs and Intangible Assets for Rate Base	S.1 L.11	483,285	480,081	478,861	535,291	562,902

Notes:
1. In 2021 and 2022 the PAMMS project was under regulatory and transferred to Intangibles in 2023.

Yukon Energy Corporation Schedule 3A - 2023
Calculation of Depreciation Expense for 2023 August 31, 2023
$000

Description	Cost at 2022 Year End	2023 Additions	2023 Disposals/ Adjustments	Cost at 2023 Year End	Proposed Depreciation Rate (Years)	Forecast 2023
Land						
Hydraulic Production	444.9	0.0		444.9	0	0.0
Diesel Production	27.7	0.0		27.7	0	0.0
Main Transmission Facilities	576.9	0.0		576.9	0	0.0
Distribution System	17.8	0.0		17.8	0	0.0
General Plant	548.0	0.0		548.0	0	0.0
Rights	128.8	0.0	1.6	127.2	50	1.6
Depreciation Study Differences						0.0
Total Land	**1,744.0**	**0.0**	**1.6**	**1,742.4**		**1.6**
Hydro Plant						
Structures and Improvements	52,844.5	1,969.4		54,813.8	72	731.3
Buildings and Improvements	10,278.7	0.0		10,278.7	40	257.0
Reservoirs, Dams, and Waterways	167,412.1	500.2		167,912.3	103	1,844.9
Hydro, Dams wtwys Twin Assets	6,711.4			6,711.4		0.0
Overhaul	9,053.0	2,461.0		11,514.0	10	905.3
Waterwheels,Turbines & Generation	28,222.8	0.0		28,222.8	85	325.4
Accessory Electric Equipment	27,366.3	0.0		27,366.3	40	725.1
Accessory Digital Equipment	851.2	0.0		851.2	20	42.6
Misc Power Plant Equipment	11,691.4	1,470.8		13,162.2	30	389.7
Fencing	107.1	0.0		107.1	30	2.7
Depreciation Study Differences						-140.3
Total Hydro Plant	**314,538.5**	**6,401.3**	**0.0**	**320,939.8**		**5,083.5**
Diesel Production						
Structures and Improvements	1,562.4	0.0		1,562.4	72	21.7
Buildings and Improvements	474.7	0.0		474.7	55	8.6
Fuel Holders, Products, and ACC	2,735.5	0.1		2,735.6	40	45.0
Generating Equipment and Prime	14,202.3	4,300.0	1,996.1	16,506.2	40	283.9
Overhaul	2,962.8	0.0		2,962.8	5	0.0
Minto Generating Equipment	243.5	0.0		243.5	12	0.0
Accessory Electric Equipment	9,428.1	51.9	541.9	8,938.0	45	208.4
Misc Power Plant Equipment	1,874.4	0.0		1,874.4	30	60.4
Depreciation Study Differences						-74.4
Total Diesel Production	**33,483.6**	**4,352.0**	**2,538.0**	**35,297.6**		**553.7**
Wind Turbine						
Wind Turbine	0.0	0.0		0.0	0	0.0
Total Wind Turbine	**0.0**	**0.0**	**0.0**	**0.0**		**0.0**
Main Transmission Facilities						
Poles and Fixtures	82,825.5	1,963.3		84,788.8	65	1,274.2
Brushing	16,756.3	0.0		16,756.3	60	263.2
Survey Costs	4,297.2	0.0		4,297.2	60	67.9
Overhead Conductors / Poles	20,202.9	0.0		20,202.9	60	313.2
Overhead Conductors / Towers	278.0	0.0		278.0	60	4.1
Substation Equipment	62,928.1	2,179.4		65,107.5	54	1,278.4
Substation VGC Group - Gold Mine	10,688.6	0.0		10,688.6	10	890.7
STATCOM - VGC Group - Gold Mine	13,991.5	0.0		13,991.5	10	1,399.1
Other - VGC Group - Gold Mine	848.0	0.0		848.0	10	84.8
Substation Buildings	8,907.6	0.0		8,907.6	55	28.1
Substation Fences	274.5	0.0		274.5	30	7.1
Depreciation Study Differences						-79.6
Total Main Transmission Facilities	**221,998.2**	**4,142.6**	**0.0**	**226,140.8**		**5,531.2**
Sub Transmission Lines						
Poles and Fixtures	4,584.0	0.0		4,584.0	65	68.5
25Kv Minto Spur- Structure	2,646.1	0.0		2,646.1	12	13.3
Brushing	41.6	0.0		41.6	60	0.7
Brushing Minto	432.5	0.0		432.5	12	2.2
Survey costs	0.0	0.0		0.0	60	0.0
Survey costs Minto	95.1	0.0		95.1	12	0.5
Overhead Conductors	1,837.9	0.0		1,837.9	60	24.3
Underground Conductors / Conduit	78.8	0.0		78.8	45	1.8
Overhead Conductors Minto	920.7	0.0		920.7	12	4.6
Substation Equipment	8,092.8	0.0		8,092.8	54	149.9
Substation Equipment Minto	7,111.2	0.0		7,111.2	12	38.8
Depreciation Study Differences						-46.0
Total Sub Transmission Lines	**25,840.9**	**0.0**	**0.0**	**25,840.9**		**258.5**

Yukon Energy Corporation Schedule 3A - 2023
Calculation of Depreciation Expense for 2023 August 31, 2023
$000

Description	Cost at 2022 Year End	2023 Additions	2023 Disposals/ Adjustments	Cost at 2023 Year End	Proposed Depreciation Rate (Years)	Forecast 2023
Distribution System						
Poles and Fixtures	10,354.7	7,432.4		17,787.1	40	246.6
Brushing	44.8	0.0		44.8	50	0.9
Survey costs	662.9	0.0		662.9	50	18.9
Overhead conductors - Poles	285.8	0.0		285.8	50	5.4
Overhead Costs	2,119.5	0.0		2,119.5	40	53.0
Underground Services	385.2	0.0		385.2	40	9.6
Underground Conduit	43.4	0.0		43.4	40	1.1
Wind Monitoring Equipment	0.0	0.0		0.0	0	0.0
Meters	312.6	0.0		312.6	16	12.4
Meter Equipment	288.4	0.0		288.4	16	11.6
Substation Equipment	1,287.2	616.3		1,903.4	40	30.3
Substation Buildings	64.8	0.0		64.8	55	1.2
Substation Fences	100.3	0.0		100.3	30	3.0
Street Lights	603.4	0.0		603.4	40	14.1
Line Transformers	4,042.5	0.0		4,042.5	35	111.2
Sentinel Lights	36.4	0.0		36.4	30	0.3
Depreciation Study Differences						50.0
Total Distribution System	**20,631.8**	**8,048.6**	**0.0**	**28,680.4**		**569.5**
Building and Other Equipment						
Survey Costs Land	4.3	0.0		4.3	50	0.1
Structures and Improvements (Hydro)	2,615.2	4,246.7		6,861.8	50	49.9
Building and Improvements	10,587.8	135.0		10,722.8	55	192.5
Office Furniture and Equipment	1,919.3	40.0		1,959.3	20	43.1
Communication Site Towers	19.3	0.0		19.3	40	0.3
Communication Site Fences	88.4	63.7		152.2	30	1.9
Computer Hardware	1,437.6	193.0		1,630.6	7	142.4
Computer Software	0.0	0.0		0.0	5	0.0
Tool and Instruments	2,848.0	366.5		3,214.5	20	111.9
Wind Monitoring Equipment	0.0	0.0		0.0	15	0.0
Communication Equipment	5,623.4	139.0		5,762.4	20	222.0
Company Owned Houses / Land	59.0	0.0		59.0	40	1.1
Company Owned Houses	2,152.4	810.2		2,962.6	40	19.2
Depreciation Study Differences						-67.3
Total Building and Other Equipment	**27,354.8**	**5,994.1**	**0.0**	**33,348.8**		**717.1**
Transportation						
Utility Vehicles	357.6	35.0		392.6	8	14.0
Sedans and Stationwagons	211.7	0.0		211.7	11	14.8
Trucks & Pole Trailer	71.8	0.0		71.8	25	2.9
Pole Trailers > 10,000 Lbs	53.7	0.0		53.7	25	2.5
Trucks 3/4 to 2 Ton	3,289.7	623.8		3,913.5	9	302.9
Trucks > 3 Ton	1,459.8	389.5		1,849.3	20	58.4
Foremost	1,003.9	0.0		1,003.9	20	60.7
Depreciation Study Differences						19.3
Total Transportation	**6,448.2**	**1,048.3**	**0.0**	**7,496.4**		**475.6**
Critical Spares						
Critical Spares	1,165.7	0.0		1,165.7	0	0.0
Total Critical Spares	**1,165.7**	**0.0**	**0.0**	**1,165.7**		**0.0**
LNG Production						
Structures and Improvements	6,184.7	0.0		6,184.7	72	85.9
Fuel Holders	13,200.7	0.0		13,200.7	60	200.4
Generator	20,891.0	0.0		20,891.0	40	522.3
Overhaul	548.4	800.0		1,348.4	2	0.0
Accessory Electric Equipment	3,655.9	0.0		3,655.9	45	81.2
Misc Power Plant Equipment	2,870.0	20.2		2,890.2	30	95.7
Fence	779.7	0.0		779.7	30	26.0
Depreciation Study Differences						-14.0
Total LNG Prodution	**48,130.4**	**820.2**	**0.0**	**48,950.6**		**997.5**
Right of Use Assets						
Right of Use Assets	1,180.9	750.1		1,931.0		113.1
Total Right of Use Assets	**1,180.9**	**750.1**	**0.0**	**1,931.0**		**113.1**
Total	**702,516.9**	**31,557.2**	**2,539.6**	**731,534.4**		**14,301.4**

Yukon Energy Corporation
Calculation of Depreciation Expense for 2024
$000

Schedule 3A - 2024
August 31, 2023

Description	Cost at 2023 Year End	2024 Additions	2024 Disposals/ Adjustments	Cost at 2024 Year End	Proposed Depreciation Rate (Years)	Forecast 2024
Land						
Hydraulic Production	444.9	0.0		444.9	0	0.0
Diesel Production	27.7	0.0		27.7	0	0.0
Main Transmission Facilities	576.9	0.0		576.9	0	0.0
Distribution System	17.8	0.0		17.8	0	0.0
General Plant	548.0	0.0		548.0	0	0.0
Rights	127.2	0.0	1.6	125.6	50	1.6
Depreciation Study Differences						0.0
Total Land	**1,742.4**	**0.0**	**1.6**	**1,740.9**		**1.6**
Hydro Plant						
Structures and Improvements	54,813.8	1,000.0		55,813.8	72	758.6
Buildings and Improvements	10,278.7	0.0		10,278.7	40	257.0
Reservoirs, Dams, and Waterways	167,912.3	0.0		167,912.3	103	1,849.7
Hydro, Dams wtwys Twin Assets	6,711.4	0.0		6,711.4		0.0
Overhaul	11,514.0	0.0		11,514.0	10	1,151.4
Waterwheels,Turbines & Generation	28,222.8	0.0		28,222.8	85	325.4
Accessory Electric Equipment	27,366.3	0.0		27,366.3	40	727.1
Accessory Digital Equipment	851.2	0.0		851.2	20	42.6
Misc Power Plant Equipment	13,162.2	225.0		13,387.2	30	438.7
Fencing	107.1	0.0		107.1	30	2.7
Depreciation Study Differences						-140.3
Total Hydro Plant	**320,939.8**	**1,225.0**	**0.0**	**322,164.8**		**5,412.9**
Diesel Production						
Structures and Improvements	1,562.4	0.0		1,562.4	72	21.7
Buildings and Improvements	474.7	0.0		474.7	55	8.6
Fuel Holders, Products, and ACC	2,735.6	0.0		2,735.6	40	45.1
Generating Equipment and Prime	16,506.2	18,175.5		34,681.6	40	390.5
Overhaul	2,962.8	450.0		3,412.8	5	0.0
Minto Generating Equipment	243.5	0.0		243.5	12	0.0
Accessory Electric Equipment	8,938.0	0.0		8,938.0	45	208.8
Misc Power Plant Equipment	1,874.4	50.0		1,924.4	30	60.4
Depreciation Study Differences						-74.4
Total Diesel Production	**35,297.6**	**18,675.5**	**0.0**	**53,973.0**		**660.8**
Wind Turbine						
Wind Turbine	0.0	0.0		0.0	0	0.0
Total Wind Turbine	**0.0**	**0.0**	**0.0**	**0.0**		**0.0**
Main Transmission Facilities						
Poles and Fixtures	84,788.8	16,448.9		101,237.6	65	1,304.3
Brushing	16,756.3	0.0		16,756.3	60	263.8
Survey Costs	4,297.2	0.0		4,297.2	60	68.0
Overhead Conductors / Poles	20,202.9	0.0		20,202.9	60	314.0
Overhead Conductors / Towers	278.0	0.0		278.0	60	4.2
Substation Equipment	65,107.5	1,184.0		66,291.5	54	1,315.9
Substation VGC Group - Gold Mine	10,688.6	0.0		10,688.6	10	890.7
STATCOM - VGC Group - Gold Mine	13,991.5	0.0		13,991.5	10	1,399.1
Other - VGC Group - Gold Mine	848.0	0.0		848.0	10	84.8
Substation Buildings	8,907.6	0.0		8,907.6	55	28.1
Substation Fences	274.5	0.0		274.5	30	7.1
Depreciation Study Differences						-79.6
Total Main Transmission Facilities	**226,140.8**	**17,632.9**	**0.0**	**243,773.6**		**5,600.5**
Sub Transmission Lines						
Poles and Fixtures	4,584.0	0.0		4,584.0	65	68.5
25Kv Minto Spur- Structure	2,646.1	0.0		2,646.1	12	13.3
Brushing	41.6	0.0		41.6	60	0.7
Brushing Minto	432.5	0.0		432.5	12	2.2
Survey costs	0.0	0.0		0.0	60	0.0
Survey costs Minto	95.1	0.0		95.1	12	0.5
Overhead Conductors	1,837.9	0.0		1,837.9	60	24.4
Underground Conductors / Conduit	78.8	0.0		78.8	45	1.8
Overhead Conductors Minto	920.7	0.0		920.7	12	4.6
Substation Equipment	8,092.8	50.0		8,142.8	54	149.9
Substation Equipment Minto	7,111.2	0.0		7,111.2	12	38.8
Depreciation Study Differences						-46.0
Total Sub Transmission Lines	**25,840.9**	**50.0**	**0.0**	**25,890.9**		**258.6**

Yukon Energy Corporation Schedule 3A - 2024
Calculation of Depreciation Expense for 2024 August 31, 2023
$000

Description	Cost at 2023 Year End	2024 Additions	2024 Disposals/ Adjustments	Cost at 2024 Year End	Proposed Depreciation Rate (Years)	Forecast 2024
Distribution System						
Poles and Fixtures	17,787.1	700.0		18,487.1	40	433.1
Brushing	44.8	0.0		44.8	50	0.9
Survey costs	662.9	0.0		662.9	50	18.9
Overhead conductors - Poles	285.8	1,926.8		2,212.6	50	5.4
Overhead Costs	2,119.5	0.0		2,119.5	40	53.0
Underground Services	385.2	0.0		385.2	40	9.6
Underground Conduit	43.4	0.0		43.4	40	1.1
Wind Monitoring Equipment	0.0	0.0		0.0	0	0.0
Meters	312.6	0.0		312.6	16	5.6
Meter Equipment	288.4	0.0		288.4	16	7.0
Substation Equipment	1,903.4	0.0		1,903.4	40	45.7
Substation Buildings	64.8	0.0		64.8	55	1.2
Substation Fences	100.3	0.0		100.3	30	3.0
Street Lights	603.4	0.0		603.4	40	14.1
Line Transformers	4,042.5	0.0		4,042.5	35	111.5
Sentinel Lights	36.4	0.0		36.4	30	0.3
Depreciation Study Differences						50.0
Total Distribution System	**28,680.4**	**2,626.8**	**0.0**	**31,307.2**		**760.3**
Building and Other Equipment						
Survey Costs Land	4.3	0.0		4.3	50	0.1
Structures and Improvements (Hydro)	6,861.8	1,200.0		8,061.8	50	134.9
Building and Improvements	10,722.8	90.0		10,812.8	55	195.0
Office Furniture and Equipment	1,959.3	25.0		1,984.3	20	43.3
Communication Site Towers	19.3	0.0		19.3	40	0.3
Communication Site Fences	152.2	25.0		177.2	30	4.0
Computer Hardware	1,630.6	730.0		2,360.6	7	153.4
Computer Software	0.0	0.0		0.0	5	0.0
Tool and Instruments	3,214.5	880.0		4,094.5	20	128.6
Wind Monitoring Equipment	0.0	0.0		0.0	15	0.0
Communication Equipment	5,762.4	260.0		6,022.4	20	223.2
Company Owned Houses / Land	59.0	0.0		59.0	40	1.1
Company Owned Houses	2,962.6	0.0		2,962.6	40	39.5
Depreciation Study Differences						-67.3
Total Building and Other Equipment	**33,348.8**	**3,210.0**	**0.0**	**36,558.8**		**856.2**
Transportation						
Utility Vehicles	392.6	35.0		427.6	8	16.9
Sedans and Stationwagons	211.7	0.0		211.7	11	14.8
Trucks & Pole Trailer	71.8	0.0		71.8	25	2.9
Pole Trailers > 10,000 Lbs	53.7	0.0		53.7	25	2.6
Trucks 3/4 to 2 Ton	3,913.5	567.0		4,480.5	9	336.8
Trucks > 3 Ton	1,849.3	0.0		1,849.3	20	77.9
Foremost	1,003.9	0.0		1,003.9	20	60.9
Depreciation Study Differences						19.3
Total Transportation	**7,496.4**	**602.0**	**0.0**	**8,098.4**		**532.0**
Critical Spares						
Critical Spares	1,165.7	0.0		1,165.7	0	0.0
Total Critical Spares	**1,165.7**	**0.0**	**0.0**	**1,165.7**		**0.0**
LNG Production						
Structures and Improvements	6,184.7	0.0		6,184.7	72	85.9
Fuel Holders	13,200.7	0.0		13,200.7	60	201.0
Generator	20,891.0	0.0		20,891.0	40	522.3
Overhaul	1,348.4	400.0		1,748.4	2	400.0
Accessory Electric Equipment	3,655.9	0.0		3,655.9	45	81.2
Misc Power Plant Equipment	2,890.2	800.0		3,690.2	30	96.3
Fence	779.7	0.0		779.7	30	26.0
Depreciation Study Differences						-14.0
Total LNG Prodution	**48,950.6**	**1,200.0**	**0.0**	**50,150.6**		**1,398.7**
Right of Use Assets						
Right of Use Assets	1,931.0			1,931.0		225.6
Total Right of Use Assets	**1,931.0**	**0.0**	**0.0**	**1,931.0**		**225.6**
Total	**731,534.4**	**45,222.1**	**1.6**	**776,755.0**		**15,707.1**

YUKON ENERGY CORPORATION Schedule 3B - 2023
Calculation of Amortization Expense for Deferred Costs and Intangibles (2023) August 31, 2023
$000

	Total Expenditures Dec 31 2022	2023 Forecast Additions	2023 Forecast Transfers /Retired	Dec 31 2023	Amortization Rate and Method	2023 Forecast Expenses
Feasibility Study						
Completed Projects:						
Gladstone	4,521			4,521	SL-10 years	452
Disaster Recovery Plan	4			4	SL-5 years	0
N-1 Event Risk Assessment	129			129	SL-5 years	26
Dyke Heating Pipe Assessment	68			68	SL-5 years	14
Dawson DT Distribution Upgrade	79			79	SL-5 years	16
Water Study Main Building	13			13	SL-5 years	3
BCP GAP Analysis	75			75	SL-5 years	15
Study Road Infrastructure May A&B	15			15	SL-5 years	3
Mayo & Aishihik Climate Change	667			667	SL-5 years	133
Elevator Study Aishik	6			6	SL-5 years	1
Radio Repeater Assessment	25			25	SL-5 years	5
Transmission Line Access Plan	88			88	SL-5 years	18
Mt Sumanik Wind Feasibility St	744			744	SL-5 years	149
Small Hydro Project	16			16	SL-5 years	3
Mayo Earthworks	90			90	SL-5 years	18
FD7 Condition Assessment	73			73	SL-5 years	15
Wareham Spillgate Leakage Reduction	53			53	SL-5 years	11
P125 Intake Trash Rack Cleaning System	59			59	SL-5 years	12
PMF Flood Study	78			78	SL-5 years	16
IPP SOP Implentation	326	70		396	SL-5 years	65
WH Post-Flood Assessment	115			115	SL-5 years	23
Emergency Preparedness Improvement	60			60	SL-5 years	12
P126 Building Renovation	196			196	SL-5 years	39
WH4 Low Water Cavitation Study & Recommendation	47			47	SL-5 years	9
WTE Contributions	(283)			(283)	SL-5 years	(7)
Southern Lakes Enhanced Storage		8,784		8,784	SL-10 years	-
Public Safety Plans		225		225	SL-5 years	-
System Wide Stability Study		200		200	SL-5 years	-
System Wide Arc Flash Study		198		198	SL-5 years	-
Mayo Civil Infrastructure Refurbishment Planning		168		168	SL-5 years	-
Digital Strategy and Policy Development		120		120	SL-5 years	-
Privacy Management Program		100		100	SL-5 years	-
Vegetation Management Plan Update		225		225	SL-5 years	-
Other Projects with <$100k Spending		319		319	SL-5 years	-
Total Feasibility Study Closed	7,263	10,410	-	17,673		1,049
Regulatory						
Completed Projects:						
DSM	3,378	1,272		4,649	SL-10 years	338
YUB 2007-8 - Part 3 Hearing	185			185	SL-45 years	4
Asset Appraisal-Replace Cost	47			47	SL-5 years	3
Victoria Gold PPA	142			142	SL-5 years	17
LED Streetlight 2015/2018	261			261	SL-5 years	52
10 Year Renewable Energy Plan	634			634	SL-5 years	127
DSM Contributions	(2,080)	(22)		(2,102)	SL-10 years	(208)
Victoria Gold PPA Contributions	(100)			(100)	SL-5 years	(12)
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)		386		386	Hearing Reserve	
GRA 2020-2021 (Hearing Reserve Acct)		23		23	Hearing Reserve	
Total Regulatory Closed	2,465	1,659	-	4,124		321
Relicensing						
Completed Projects:						
Aishihik 2020 3 Year Relicensing	112			112	License term	6
Aishihik 2022 5 Year Relicensing	3,903	575		4,479	License term	781
Whitehorse Hatchery Water Relicensing	40			40	License term	2
Whitehorse Relicensing	286			286	License term	21
Mayo Relicensing	129			129	License term	11
Total Relicensing Closed	4,470	575	-	5,046		820
Dam Safety Review						
Completed projects	254			254	SL-5 years	51
Total Deferred Costs	**14,453**	**12,644**	**0**	**27,097**		**2,241**
Intangibles						
Completed Projects:						
Software Costs	1,185	441		1,627	SL-5 years	226
Financial Software Costs	7,386			7,386	SL-10 years	492
PAMMS Asset Management Framework		5,466		5,466	SL-10 years	
Total Intangibles Closed	8,572	5,907	-	14,479		718
Total Deferred and Intangibles Closed	**23,025**	**18,551**	**0**	**41,576**		**2,959**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

YUKON ENERGY CORPORATION Schedule 3B - 2024
Calculation of Amortization Expense for Deferred Costs and Intangibles (2024) August 31, 2023
$000

	Total Expenditures					
	Dec 31	2024 Forecast		Dec 31	Amortization	2024 Forecast
	2023	Additions	Transfers /Retired	2024	Rate and Method	Expenses
Feasibility Study						
Completed Projects:						
Gladstone	4,521			4,521	SL-10 years	452
Dyke Heating Pipe Assessment	68			68	SL-5 years	10
Dawson DT Distribution Upgrade	79			79	SL-5 years	16
Water Study Main Building	13			13	SL-5 years	1
BCP GAP Analysis	75			75	SL-5 years	15
Study Road Infrastructure May A&B	15			15	SL-5 years	1
Mayo & Aishihik Climate Change	667			667	SL-5 years	133
Elevator Study Aishik	6			6	SL-5 years	1
Radio Repeater Assessment	25			25	SL-5 years	5
Transmission Line Access Plan	88			88	SL-5 years	18
Mt Sumanik Wind Feasibility St	744			744	SL-5 years	149
Small Hydro Project	16			16	SL-5 years	3
Mayo Earthworks	90			90	SL-5 years	18
FD7 Condition Assessment	73			73	SL-5 years	15
Wareham Spillgate Leakage Reduction	53			53	SL-5 years	11
P125 Intake Trash Rack Cleaning System	59			59	SL-5 years	12
PMF Flood Study	78			78	SL-5 years	16
IPP SOP Implentation	396			396	SL-5 years	79
WH Post-Flood Assessment	115			115	SL-5 years	23
Emergency Preparedness Improvement	60			60	SL-5 years	12
P126 Building Renovation	196			196	SL-5 years	39
WH4 Low Water Cavitation Study & Recommendation	47			47	SL-5 years	9
Southern Lakes Enhanced Storage	8,784			8,784	SL-10 years	878
Public Safety Plans	225			225	SL-5 years	45
System Wide Stability Study	200			200	SL-5 years	40
System Wide Arc Flash Study	198			198	SL-5 years	40
Mayo Civil Infrastructure Refurbishment Planning	168			168	SL-5 years	34
Digital Strategy and Policy Development	120			120	SL-5 years	24
Privacy Management Program	100			100	SL-5 years	20
Vegetation Management Plan Update	225			225	SL-5 years	45
Cyber Security Framework		140		140	SL-5 years	
Transmission Line Detailed Inspection Program		250		250	SL-5 years	
Gates/TIV's Certification Assessment System Wide		200		200	SL-5 years	40
Digital Reporting Review		125		125	SL-5 years	
Records Policy Planning and Program Development		100		100	SL-5 years	
Breaker Condition Assessment		100		100	SL-5 years	
Other Projects with <$100k Spending	319	(10)		309	SL-5 years	64
Total Feasibility Study Closed	17,823	905	-	18,728		2,268
Regulatory						
Completed Projects:						
DSM	4,649	1,160		5,809	SL-10 years	465
YUB 2007-8 - Part 3 Hearing	185			185	SL-45 years	4
10 Year Renewable Energy Plan	634			634	SL-5 years	127
DSM Contributions	(2,102)			(2,102)	SL-10 years	(210)
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)	386			386	Hearing Reserve	
GRA 2020-2021 (Hearing Reserve Acct)	23			23	Hearing Reserve	
GRA 2023-2024 (Hearing Reserve Acct)		250		250	Hearing Reserve	
Total Regulatory Closed	3,775	1,410	-	5,185		386
Relicensing						
Completed Projects:						
Aishihik 2022 5 Year Relicensing	4,479			4,479	License term	896
Whitehorse Hatchery Water Relicensing	40			40	License term	2
Whitehorse Relicensing	286			286	License term	20
Mayo Relicensing	129			129	License term	11
WRGS Thermal Assessment & Permitting		413		413	License term	
Total Relicensing Closed	4,933	413	-	5,346		928
Dam Safety Review						
Completed projects	254			254	SL-5 years	51
Total Deferred Costs	**26,786**	**2,728**	**0**	**29,514**		**3,632**
Intangibles						
Completed Projects:						
Software Costs	1,627	380		2,007	SL-5 years	279
Financial Software Costs	7,386			7,386	SL-10 years	455
PAMMS Asset Management Framework	5,466			5,466	SL-10 years	547
Total Intangibles Closed	14,479	380	-	14,859		1,281
Total Deferred and Intangibles Closed	**41,265**	**3,108**	**0**	**44,373**		**4,913**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

Yukon Energy Corporation
Cost of Capital Calculation
($000s)

Schedule 4
August 31, 2023

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio		Mid Year Rate Base	Mid Year Cost Rate	Return
	2021 GRA Compliance				**Deemed Ratio**			
1	Long-Term debt	S.11 L.19	185,526	60.0%	60.0%	185,679	2.94%	5,453
2	Common Stock		123,705	40.0%	40.0%	123,786	8.65%	10,708
3	Total	S.5 L.3	309,231	100.0%	100.0%	309,466	5.22%	16,161
	2021 Actual							
7	Long-Term debt	S.11 L.19	175,620	57.8%		173,892	2.93%	5,102
8	Common Stock		128,322	42.2%		127,060	8.93%	11,346
9	Total	S.5 L.3	303,942	100.0%		300,951	5.47%	16,448
	2022 Actual							
10	Long-Term debt	S.11 L.19	181,949	56.0%		169,841	2.88%	4,896
11	Common Stock		143,174	44.0%		133,646	10.17%	13,607
12	Total	S.5 L.3	325,123	100.0%		303,487	3.17%	18,503
	Forecast 2023				**Deemed Ratio**			
13	Long-Term debt	S.11 L.19	201,610	58.0%	60.0%	199,437	3.31%	6,605
14	Common Stock		146,195	42.0%	40.0%	132,958	8.70%	11,567
15	Total	S.5 L.3	347,804	100.0%	100.0%	332,396	5.47%	18,172
	Forecast 2024				**Deemed Ratio**			
19	Long-Term debt	S.11 L.19	225,510	60.0%	60.0%	225,603	3.43%	7,729
20	Common Stock		150,083	40.0%	40.0%	150,402	8.70%	13,085
21	Total	S.5 L.3	375,593	100.0%	100.0%	376,004	5.54%	20,814

Yukon Energy Corporation
Utility Revenue Requirement
($000s)

Schedule 5
August 31, 2023

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Net rate base	S.1 L.23	309,466	300,951	303,487	332,396	376,004
2	Average Rate of return on rate base		5.22%	5.47%	6.10%	5.47%	5.54%
3	Utility income	S.8 L.1	16,161	16,448	18,503	18,172	20,814
4	Utility expenses						
5	Operating and maintenance (note 1)	S.6 L.3	43,211	40,096	44,641	50,017	53,178
6	Taxes other than income	S.6 L.4	750	739	743	758	777
7	Amortization of deferred costs	S.6 L.5	4,063	5,529	3,886	3,657	5,594
8	Reserve for Injuries and Damages	S.6 L.6	616	616	616	616	616
9	Depreciation	S.6 L.7	13,436	14,927	13,310	14,301	15,707
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(4,684)	(6,347)	(5,384)	(5,918)	(6,096)
11	Disallowed depreciation		(238)	(416)	(718)	(44)	(44)
12	Donations		(120)	(117)	(121)	(120)	(120)
13	Total utility expenses		57,033	55,026	56,972	63,268	69,611
14	Revenue Requirement	S.6 L.1	73,193	71,473	75,475	81,440	90,425

Note 1: Includes fuel expenses and purchased power.

Yukon Energy Corporation
Statement of Earnings
($000s)

Schedule 6
August 31, 2023

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Revenues (note 1)	S.5 L.14	73,193	71,473	75,475	81,440	90,425
2	**Operating expenses**						
3	Operating and maintenance	S.10 L.15	43,211	40,096	44,641	50,017	53,178
4	Taxes other than income	S.5 L.6	750	739	743	758	777
5	Amortize deferred costs		4,063	5,529	3,886	3,657	5,594
6	Reserve for Injuries and Damages	S.5 L.8	616	616	616	616	616
7	Depreciation		13,436	14,927	13,310	14,301	15,707
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(4,684)	(6,347)	(5,384)	(5,918)	(6,096)
9	Total		57,391	55,559	57,811	63,432	69,775
10	**Operating income**		15,802	15,914	17,664	18,008	20,650
11	**Other income**						
12	Allowed for Funds Used	S.8 L.2	1,188	942	1,060	2,215	3,723
13	Miscellaneous (note 2)	S.8 L.3	(131)	(812)	(888)	(1,171)	(3,265)
14	Total		1,057	130	172	1,044	458
15	**Other expenses**						
16	Interest expense	S.8 L.4	5,655	2,768	(1,822)	8,699	10,165
17	Total		5,655	2,768	(1,822)	8,699	10,165
18	**Net earnings**	S.8 L.8	11,205	13,276	19,658	10,353	10,943

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
August 31, 2023

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Balance at beginning of year		68,883	64,263	82,445	93,966	88,486
	Add:						
2	Net earnings	S.6 L.18	11,205	13,276	19,658	10,353	10,943
3	IFRS Comprehensive Income Adjustment			4,906	3,364	-	-
4	Balance at end of year before dividend		80,088	82,445	105,466	104,320	99,429
	Less:						
5	Common Dividends (note 1)		13,592	-	11,500	15,834	-
6	Balance at end of year		66,495	82,445	93,966	88,486	99,429
	Shareholder's Equity						
7	Common shares		56,294	54,968	54,968	54,968	57,284
8	Retained earnings		66,495	82,445	93,966	88,486	99,429
9	Total		122,789	137,413	148,935	143,454	156,712

Note:
1. YDC equity injection/dividend estimates required in order to maintain 60/40 debt to equity ratio.

Yukon Energy Corporation
Reconciliation of Utility Income to Net Earnings
($000s)

Schedule 8
August 31, 2023

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Utility Income (Return on Rate Base)	S.5 L.3	16,161	16,448	18,503	18,172	20,814
	Add:						
2	Allowance for funds used	S.6 L.12	1,188	942	1,060	2,215	3,723
3	Other income (expenses)	S.6 L.13	(131)	(812)	(888)	(1,171)	(3,265)
			17,218	16,578	18,675	19,216	21,272
	Less:						
4	Interest - long-term	S.6 L.17	5,655	2,768	(1,822)	8,699	10,165
5	Donations	S.5 L.12	120	117	121	120	120
6	Disallowed costs		-	-	-	-	-
7	Disallowed depreciation	S.5 L.11	238	416	718	44	44
			6,013	3,302	(983)	8,863	10,329
8	Net earnings	S.6 L.18	11,205	13,276	19,658	10,353	10,943

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues
($000s)

Schedule 9
August 31, 2023

Line No.	Description	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	**Residential**					
2	Customers	1,780	1,813	1,822	1,858	1,898
3	Sales in MWh	16,210	17,421	17,334	17,693	18,090
4	MWh sales per customer	9.1	9.6	9.5	9.5	9.5
5	Revenue ($000s)	2,384	2,513	2,472	2,532	2,611
6	Cents per KWh	14.7	14.4	14.3	14.3	14.4
7	**General Service**					
8	Customers	514	528	519	529	536
9	Sales in MWh	32,323	29,584	30,662	38,569	44,698
10	MWh sales per customer	62.9	56.0	59.1	72.9	83.4
11	Revenue ($000s)	5,388	4,911	5,005	6,272	7,175
12	Cents per KWh	16.7	16.6	16.3	16.3	16.1
13	**Industrial**					
14	Sales in MWh	102,904	91,143	95,169	75,045	69,368
15	Revenue ($000s)	11,481	11,129	12,206	9,718	8,771
16	Cents per KWh	11.2	12.2	12.8	12.9	12.6
17	**Street lights**					
18	Sales in MWh	168	168	168	168	168
19	Revenue ($000s)	82	82	82	82	82
20	Cents per KWh	48.8	48.8	48.9	48.9	48.9
21	**Space lights**					
22	Sales in MWh	10	9	9	9	9
23	Revenue ($000s)	3	2	2	2	2
24	Cents per KWh	26.6	27.2	27.3	27.3	27.3
25	**Total Company - Firm Retail and Industrial**					
26	Customers	2,293	2,341	2,341	2,387	2,434
27	Sales in MWh	151,614	138,325	143,341	131,484	132,333
28	Revenue ($000s)	19,337	18,638	19,767	18,606	18,642
29	Cents per KWh	12.8	13.5	13.8	14.2	14.1
30	**Wholesale sales**					
31	Sales in MWh	343,537	348,983	346,339	351,291	355,857
32	Revenue ($000s)	28,507	28,959	29,170	29,150	29,529
33	Cents per KWh	8.3	8.3	8.4	8.3	8.3
34	**Total Company - Firm**					
35	Sales in MWh	495,151	487,308	489,680	482,775	488,190
36	Revenue ($000s)	47,844	47,597	48,937	47,756	48,171
37	Cents per KWh	9.7	9.8	10.0	9.9	9.9
38	**Secondary**					
39	Sales in MWh	0	4,739	3,448	2,931	2,931
40	Revenue ($000s)	0	330	365	358	358
41	Cents per KWh	0.0	7.0	10.6	12.2	12.2
42	**Total Company**					
43	Sales in MWh	495,151	492,047	493,128	485,706	491,121
44	Revenue ($000s)	47,844	47,927	49,302	48,114	48,528
45	Cents per KWh	9.7	9.7	10.0	9.9	9.9
46	Rider J	15,887	19,430	26,348	26,265	26,183
47	GRA Increase Req'd	9,149			6,667	15,320
48	Total Sales of Power	72,880	67,357	75,650	81,046	90,031
49	Other Revenues	369	-1,471	382	394	394
50	Total Revenues	73,249	65,886	76,032	81,440	90,425

Yukon Energy Corporation
Summary of Operating and Maintenance Expenses
($000s)

Schedule 10
August 31, 2023

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	**Utility operations**						
2	Production		10,438	10,360	11,320	13,490	15,525
3	Transmission and distribution		3,188	3,133	2,972	3,273	3,295
4	General		1,763	1,628	1,699	1,780	1,697
5	Administration and general		10,397	10,641	11,603	12,893	13,157
6	Insurance		1,423	1,550	1,875	2,190	2,417
7	Sub-total		27,209	27,312	29,469	33,625	36,091
8	Donations		120	117	121	120	120
9	Sub-total		120	117	121	120	120
10	O&M not including fuel and						
11	purchased power		27,329	27,429	29,590	33,745	36,211
12	Fuel		15,829	12,618	14,725	15,122	13,831
13	Purchased power		53	49	326	1,150	3,136
14	Sub-total		15,882	12,667	15,051	16,272	16,967
15	Total operating and maintenance	S.6 L.3	43,211	40,096	44,641	50,017	53,178
	O&M Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the following:						
16	*Reserve for Injuries and Damages*		*616*	*616*	*616*	*616*	*616*
17	*Property Taxes*		*750*	*739*	*743*	*758*	*777*
18	*less: Donations*		*-120*	*-117*	*-121*	*-120*	*-120*
19	*O&M per Table 3.3 (Tab 3)*		*28,575*	*28,667*	*30,828*	*34,999*	*37,484*

Yukon Energy Corporation
Summary of Labour Costs
($000s)

Schedule 10A
August 31, 2023

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	**Total FTEs**	Tab 3, Table 3.4	100.6	101.9	107.0	114.0	119.8
2	**Total Labour Costs**		15,719	15,807	15,753	18,489	19,695
3	O&M Labour Costs	Sum Lines 5-9	13,016	13,167	13,675	15,183	16,079
4	Labour Costs to Capital		2,703	2,640	2,077	3,305	3,616
	Labour Costs						
5	Production		4,802	5,076	5,051	5,693	6,034
6	Transmission		674	645	548	657	666
7	Distribution		629	701	687	752	764
8	General		372	275	291	343	350
9	Administration		6,539	6,471	7,098	7,739	8,265
10	Total Labour		13,016	13,167	13,675	15,183	16,079

Yukon Energy Corporation Schedule 11
Summary of Cost of Long - Term Debt August 31, 2023
($000s)

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
	Long-Term Debt Balance						
1	YDC Mayo B Flexible Term Debt		18,531	18,531	18,194	17,857	17,520
2	TD Bank Swap		7,858	7,831	7,413	6,987	6,552
3	YDC $92.5M Debt		66,672	66,672	62,988	59,304	55,620
4	YDC $5.5M Debt		5,505	5,505	5,505	5,505	5,505
5	YDC $21.0M Debt		15,948	15,948	15,109	14,269	13,430
6	YDC $12.1M Debt		12,136	12,136	12,136	12,136	12,136
7	TD Bank Swap		21,554	21,527	20,843	20,135	19,403
8	TD Bank Swap		6,303	6,295	6,089	5,877	5,659
9	YDC $2.9M Debt		2,871	2,871	2,871	2,871	2,871
10	2020 New Debt		12,715	4,640	4,488	4,333	4,175
11	YDC Debt - 2020		8,760	3,959	3,959	3,959	3,959
12	$7.7M TD Swap - 2021		0	7,518	7,301	7,079	6,850
13	$17.9M TD Swap - 2022		1,648	0	17,914	17,598	17,269
14	2023 New Debt			0	0	34,679	34,679
15	2024 New Debt			0	0	0	26,738
16	Minto Decommissioning Reserve		2,816	2,812	2,843	2,976	3,087
17	Current year-end balance		183,317	176,245	187,653	215,566	235,453
18	Previous year-end balance		187,736	174,995	176,245	187,653	215,566
19	Mid Year		185,526	175,620	181,949	201,610	225,510
	Interest Expenses						
20	YDC Mayo B Flexible Term Debt		1,030	1,030	1,012	993	975
21	TD Bank Swap		217	166	158	149	140
22	YDC $92.5M Debt		1,886	1,886	1,787	1,688	1,589
23	YDC $5.5M Debt		132	132	132	132	132
24	YDC $21.0M Debt		371	371	352	334	315
25	YDC $12.1M Debt		255	255	255	358	359
26	TD Bank Swap		803	744	721	697	673
27	TD Bank Swap		186	169	164	158	153
28	YDC $2.9M Debt		83	83	83	83	83
29	2020 New Debt		278	97	94	91	88
30	YDC Debt - 2020		192	62	62	62	62
31	$7.7M TD Swap - 2021		0	146	214	208	201
32	$17.9M TD Swap - 2022			0	183	724	711
33	2023 New Debt			0	0	860	1,467
34	2024 New Debt			0	0	0	663
35	Minto Decommissioning Reserve		16	13	31	133	110
36	Capital Lease Interest			0	2	6	5
37	**Total Cost of Interest**		5,449	5,153	5,249	6,677	7,726
38	Mid-Year Cost of Debt		2.94%	2.93%	2.89%	3.31%	3.43%

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 for the 2023 and 2024 test years, including the following:

- Background;
- Yukon Energy Fair ROE for 2023 and 2024; 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).

Since 1998, Yukon Energy has focused on using a simplified approach to determining a "fair return" that relies on reference to formulaic approaches established by the British Columbia Utilities Commission (BCUC) or other regulators.[1] Use of a simplified approach has been approved by the Yukon Utilities Board Board (YUB or Board) in each subsequent GRA application as an expedient and cost effective means of determining return. Board Order 2009-08 established the BCUC approach would be the precedent for Yukon and would continue to be a precedent for the jurisdiction until otherwise ordered.

Since 2009, the BCUC has determined a Benchmark ROE for FortisBC Energy Inc (FEI) through a generic cost of capital proceeding, with relevant risk premiums established separately for other BC regulated utilities.[2] A generic cost of capital proceeding was completed in 2013[3] and in 2016[4] to determine an ROE for FEI – the BCUC benchmark utility. The 2016 proceeding re-confirmed the 8.75% benchmark ROE established for FEI by the BCUC in 2013.

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[1] A form of BCUC benchmark approach has been used in the 2005 Required Revenues and Related Matters Proceeding; the 2008/2009 YECL General Rate Application; the 2008/09 Yukon Energy General Rate Application; the 2013-15 YECL General Rate Application; the 2016/17 AEY Generation Rate Application; the Yukon Energy 2017/18 General Rate Application and the Yukon Energy 2021 General Rate Application.

[2] After 2009, BCUC Terasen ROE decision (Order G-158-09) eliminated the automatic adjustment mechanism that had been in place, and ordered Terasen Gas Inc. (now FortisBC Energy) 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.

[3] BCUC Generic Cost of Capital Proceeding, Order G-75-13 established a return on equity for the benchmark utility, FortisbC Energy Inc (FEI), at 8.75 percent effective January 1, 2013.

A separate proceeding to determine cost of capital and relevant risk premiums for other BCUC regulated utilities was completed in 2014.[5]

The BCUC is currently undertaking a Stage 1 GCOC proceeding to review the existing benchmark ROE. A decision is expected to be released later this year. FEI submitted a final argument to revise the benchmark ROE upwards to 10% given the existing business and financial risk.

In recent proceedings, YEC has used the 8.75% benchmark and the Board has approved a risk premium (ranging from 45[6] to 40[7] basis points) above the benchmark to recognize YEC's smaller size and higher risks related to generation, isolated grid and customer diversity.

8.2 YUKON ENERGY FAIR ROE FOR 2023 AND 2024

In respect of the 2023 and 2024 test years, Yukon Energy is proposing an approach for determining fair ROE that is consistent with underlying principles provided in past Board Orders. The approach steps outlined below include reference to the BCUC benchmark return on equity for a low risk utility, with adjustments to reflect specific added risks related to Yukon Energy based on BCUC risk premium assessments for comparator utilities. This approach offers a simple, transparent and cost effective method to determine a consistent and fair return for Yukon utilities.

- **Step 1 – Determine Low-Risk Benchmark Utility ROE:** For the 2023 and 2024 test years, Yukon Energy proposes to continue to adopt the BCUC benchmark ROE of 8.75%,[8] as most recently approved in Board Order 2022-03 and 2023-01, pending the final outcome of the ongoing BCUC GCOC proceeding. A final decision is expected regarding the GCOC proceeding before the completion of Yukon Energy's GRA Application proceeding. YEC proposes that the benchmark ROE be adjusted to align with the final BCUC decision for the benchmark utility. AEY's recently filed 2023/24 GRA proposes use of the same BCUC benchmark ROE.

- **Step 2 – Apply Yukon Energy Fair ROE by Incorporating the Risk Premium for Yukon Energy:** The established approach requires that the appropriate fair return on common equity

[4] BCUC Order G-129-16 regarding the FEI Application for its Common Equity Component and Return on Equity for 2016, approved an ROE for FEI of 8.75.
[5] BCUC Generic Cost of Capital Proceeding Stage 2 Order G-47-14 established equity risk premium over the benchmark utility for FortisBC (Electric) of 40 basis points and for PNG West of 75 basis points.
[6] Approved for the 2017 and 2018 test years by Order 2018-10.
[7] Approved for the 2021 test year by Order 2023-01, Appendix A.
[8] BCUC Generic Cost of Capital (GCOC) benchmark rate as set in BCUC Decision and Order G-129-16. At the time of preparation of this Application the benchmark has not been updated from the 8.75% approved in BCUC Decision and Order G-129-16 but is expected to be updated later this year by the completion of the GCOC proceeding initiated in 2021.

incorporate a risk premium determined relative to the benchmark utility ROE. Recent YUB decisions have approved a YEC risk premium ranging between 40-45 basis points. As reviewed in Section 8.3, based on BCUC decisions to date and the approach previously adopted, YEC is seeking a risk premium of 45 basis points (at the top of the range of what has been approved in recent GRAs). This would result in a fair return on common equity for Yukon Energy of 9.20% (8.75 + 0.45) prior to Step 3 below.

AEY has recently filed its GRA and has applied for a risk premium of 75 basis points, versus the 25 basis points AEY risk premium last approved by the YUB. YEC's risk has historically been consistently assessed to be higher than AEY's – and there is no evidence of any change to their relative risk profiles that would suggest this would not be the case today. Accordingly, YEC's risk premium will need to continue to be higher for the test years than the final risk premium approved for AEY.

- **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 8.70% that is 0.5 basis points below the low-risk benchmark utility rate of return determined by the BCUC (45 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 8.70%, subject to adjustment as required for any updated BCUC benchmark ROE determination.

8.3 BASIS FOR RISK PREMIUM ADDER

In determining a fair risk premium of 45 basis points, Yukon Energy reviewed past GRA precedents, AEY's recent GRA 2023/24 filing, previous Board orders, its risk exposure, as well as relevant BCUC decisions which indicate a current risk premium range of 40 to 75 basis points for comparator utilities. The proposed 45 basis point risk premium was selected based on current information relating to comparable utilities and exposure to risks.

1. **Appropriate comparator utilities:** The Board in Order 2018-10 recognized FortisBC (Electric) and AEY as appropriate comparators for determining YEC's risk premium [i.e., YEC has more risk

than FortisBC (Electric) and AEY] but did not accept PNG-West as an appropriate comparator utility.[9]

The Board in Order 2023-01 indicated its view that Yukon Energy may be less comparable to FortisBC (Electric) due to issuance of OIC 2021/16,[10] but noted that YEC faces some incremental risk with thermal production costs for incremental loads relative to FortisBC.

2. **Past Precedents:** In Order 2018-10, the Board awarded a 45 basis point risk premium adder to YEC to compensate for its small size and risk related to generation, isolated grid and customer diversity. Yukon Energy was considered to have higher risk than FortisBC [Electric] with its 40 basis points approved risk premium and lower risk than PNG-West with its 75 basis points approved risk premium.

   For the 2021 GRA application as indicated above, the Board awarded a 40 basis point risk premium adder for Yukon Energy in recognition of its small size (25 basis point), a further recognition of risks for generation, isolated grid and customer diversity (20 basis point) and less 5 basis points due to the Board's assessment of changes (due to OIC 2021/16) in risks since Decision 2018-10 relative to Fortis BC (Electric).[11] In effect, the Board confirmed that YEC risk premium was at least the same as FortisBC (Electric), and (based on OIC 2021/16) elected to make no finding on whether YEC faces more risk than FortisBC (Electric).

In order to assess YEC's risks relative to other utilities, it is relevant to review all relevant key factors. Tables 8.1 and 8.2 provide additional background information regarding YEC's risk relative to FortisBC (Electric) and other BC utilities. This includes information regarding relative size of operations and financial structure; and nature of business.

- **Comparison of YEC to BC Utilities Size of Operations and Financial Structure** – Updated information on FortisBC (Electric) operations relative to Yukon Energy's operations remains similar to comparisons provided in prior applications in 2017/18 and 2021, highlighting that

[9] This was based on the negative customer growth it has been experiencing for nine consecutive years covering the 2003 to 2012 period and decline in total system throughput by 87 percent over the same time frame.

[10] Due to lack of evidence on existence of asymmetric risk profile the Board made no findings on whether YEC faces more risk than FortisBC (Electric). Board Order 2023-01, Appendix A, paragraph 41.

[11] See Appendix A, Board Order 2023-01, footnote 34. Yukon Energy was considered by the Board in Order 2023-01 (Appendix A, paragraph 41) to have an asymmetric risk and benefit profile due to the removal of water-related risk from OIC 2021/16 when compared to Fortis BC (Electric), and the Board made no finding on whether YEC faces more risk than FortisBC (Electric). However, it was accepted by the Board in Appendix A, Board Order 2023-01 (paragraphs 42-46) that YEC has a cost risk exposure related to incremental load with respect to long-term average water conditions and load in excess of forecast. The Board's limitation of YEC's risk premium to the same 40 basis points as FortisBC (Electric) was apparently based on its conclusion that after OIC 2021/16 YEC had a greater benefit from incremental sales versus its costs risks than Fortis BC (Electric).

overall YEC has more risk than FortisBC (Electric). In 2022, FortisBC (Electric) operations had approximately 148,861 customers, approximately $1,583 million in rate base, and a 60/40 debt/equity ratio. This is compared to YEC's 2,341 customer base and $303 million rate base. While Yukon Energy's financial structure is the same as FortisBC (Electric), the customer count was at approximately 1.6% of FortisBC (Electric); and its rate base was approximately 20% that of FortisBC (Electric). This is similar to the comparison provided in 2021.

On the other hand, information relating to AEY indicates that it has approximately 20,308 customers and rate base of $115.0 million and a 60/40 debt/equity ratio as at 2022. This indicates that YEC has just about 11% of AEY's customer base while they maintain same capital structure.

- **Comparison of YEC to BC Utilities – Nature of Business** - YEC continues to have greater business risk than FortisBC (Electric) 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 prior applications. YEC's business risk related to industrial customers has fluctuated since 2005 due to the connection and loss of industrial customers, more recently, lower Victoria Gold and Hecla Yukon sales in 2021 and closure of Minto industrial operations in 2023 as indicated in Tab 2.

In summary, the information in Tables 8.1 and 8.2 reflects the continuing applicability of setting the YEC risk premium relative to the BCUC ROE benchmark at 45 basis points based on a fair analysis of risks and comparative utilities review confirming that YEC's overall risk is still greater than FortisBC (Electric) as well as AEY.

Table 8.1:
Comparison of YEC to BC Utilities Size of Operations and Financial Structure (2022)

	YEC	Fortis BC Inc. (Electric)	AEY
Revenues ($millions)	75.5	474.0	62.6
Rate base ($millions)	303.4	1,583.0	115.0
Number of employees	107	518	73
Number of customers	2,341	148,861	20,308
Capital Structure			
Debt/Equity ratio	60%/40%	60%/40%	60%/40%
ROE Benchmark	8.75%	8.75%	8.75%
ROE Risk Adder	0.40%	0.40%	0.25%
Fair ROE Approved	9.15%	9.15%	9.00%
YEC Final ROE after OIC 1995/90	8.65%		

Notes:

1. The information for Yukon Energy as provided in Tab 2 and Tab 3 tables. ROE benchmark and risk adder are based on YUB Order 2023-01 in relation to YEC's 2021 GRA. Risk added reflects a risk premium of 40 basis points less 50 basis points pursuant to OIC 1995/90.
2. The information for Fortis BC is based on 2022 Financial Statements available at: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/fortisbc-electric_fs-with-notes_q4_2022_c2-audit_sedar.pdf?sfvrsn=e6dd73d3_1 [accessed on July 18, 2023]. The revenue information on page 7; rate base on page 16. Number of customers, capital structure and ROE based on information available from Annual Review for 2023 Rates https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/220805-fbc-annual-review-for-2023-rates-application-ff.pdf?sfvrsn=499d8d1f_2 [accessed on July 18, 2023]. The info on capital structure and ROE is based on page 77 and number of customers is accessed from Appendix A2, page 6. Number of employees from https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/180925_fbc-ar-2019-rates_bcuc-ir1-response_ff.pdf See response to information request #9 from BCUC (provides information for 2018).
3. The capital structure and ROE for Fortis BC reflect allowed structure and allowed ROE.
4. The information for AEY is based on AEY's 2023/24 GRA. Approved ROE is based on AEY's 2016-17 GRA and YUB Order 2017-01.

Table 8.2:
Comparison of YEC to BC Utilities - Nature of Business (2022)

	YEC	Fortis BC Inc. (Electricity)	ATCO Electric Yukon
Services	Electricity	Electricity	Electricity
Acquisition of Product			
Hydroelectric	92%	45%	3%
Thermal/Other	8%	-	6%
Purchased		55%	92%
Revenue share by customer type			
Residential	4.4%	43.9%	47.5%
Commercial	8.9%	23.2%	49.6%
Industrial	21.2%	9.6%	0.0%
Wholesale	64.9%	11.1%	0.1%
Other/misc	0.6%	12.3%	2.9%
Energy sales share			
Residential	3.5%	37.5%	51.6%
Commercial	6.3%	27.7%	46.2%
Industrial	19.4%	16.7%	0.0%
Wholesale	70.8%	16.7%	0.1%
Other/misc	0.0%	1.4%	2.1%

Notes:

1. The information for Yukon Energy is from Tab 2 tables.
2. 2. The information for Fortis BC is based on 2022 Financial Statements available at: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/fortisbc-electric_fs-with-notes_q4_2022_c2-audit_sedar.pdf?sfvrsn=e6dd73d3_1 page 30 [accessed on July 18, 2023]; Annual Review for 2023 Rates, https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/220805-fbc-annual-review-for-2023-rates-application-ff.pdf?sfvrsn=499d8d1f_2 pages 17 and 37.
3. The information for AEY is based on AEY's 2023/24 GRA.

TAB 9

2022 AUDITED FINANCIAL STATEMENTS

Yukon Energy Corporation

Financial Statements

December 31, 2022

Yukon Energy Corporation

Financial Statements

December 31, 2022 **Page**

#2 Miles Canyon Road
Box 5920, Whitehorse
Yukon Y1A 6S7
yukonenergy.ca

May 10, 2023

Management's Responsibility for Financial Reporting

Management is responsible for the preparation of the financial statements and all other financial information relating to the Utility contained in this annual report. The financial statements have been prepared in conformity with International Financial Reporting Standards using methods appropriate for the industry in which the Utility operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the financial statements. The Auditor General of Canada is the external auditor of the Utility.

Management has established internal accounting control systems to meet its responsibilities for reliable and accurate reporting. These systems include policies and procedures, the careful selection and training of qualified personnel and an organizational structure that provides for the appropriate delegation of authority and segregation of responsibilities.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management and the independent auditor to discuss auditing and financial matters to assure that management is carrying out its responsibilities and to review the financial statements. The auditors have full and free access to the Audit Committee and management.

Chris Milner
President and CEO

Ed Mollard
Vice President Finance, and Chief Financial Officer

Office of the Auditor General of Canada — Bureau du vérificateur général du Canada

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of the Yukon Energy Corporation

Report on the Audit of the Financial Statements

Opinion

We have audited the financial statements of the Yukon Energy Corporation (the Corporation), which comprise the statement of financial position as at 31 December 2022, and the statement of operations and other comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at 31 December 2022, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRSs).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRSs, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Corporation's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Report on Compliance with Specified Authorities

Opinion

In conjunction with the audit of the financial statements, we have audited transactions of the Yukon Energy Corporation coming to our notice for compliance with specified authorities. The specified authorities against which compliance was audited are the *Public Utilities Act* and regulations, the *Business Corporations Act* and regulations, and the articles and by-laws of the Yukon Energy Corporation.

In our opinion, the transactions of the Yukon Energy Corporation that came to our notice during the audit of the financial statements have complied, in all material respects, with the specified authorities referred to above.

Responsibilities of Management for Compliance with Specified Authorities

Management is responsible for the Yukon Energy Corporation's compliance with the specified authorities named above, and for such internal control as management determines is necessary to enable the Yukon Energy Corporation to comply with the specified authorities.

Auditor's Responsibilities for the Audit of Compliance with Specified Authorities

Our audit responsibilities include planning and performing procedures to provide an audit opinion and reporting on whether the transactions coming to our notice during the audit of the financial statements are in compliance with the specified authorities referred to above.

Lana Dar

Lana Dar, CPA, CA
Principal
for the Auditor General of Canada

Vancouver, Canada
10 May 2023

Yukon Energy Corporation
Statement of Financial Position
(in thousands of Canadian dollars)

As at	December 31 2022	December 31 2021
Assets		
Current		
Accounts receivable (Note 5)	$ 20,404	$ 16,123
Inventories (Note 6)	4,944	4,354
Prepaid expenses	689	1,323
	26,037	21,800
Non-current		
Property, plant and equipment (Note 7)	520,472	494,002
Intangible assets (Note 8)	21,671	18,895
Right-of-use assets (Note 9)	1,231	234
Derivative related asset (Note 26)	4,908	-
Total assets	**574,319**	534,931
Regulatory deferral account debit balances (Note 10(a))	32,513	31,804
Total assets and regulatory deferral account debit balances	**$ 606,832**	$ 566,735
Liabilities		
Current		
Bank indebtedness (Note 11)	$ 11,123	$ 12,774
Accounts payable and accrued liabilities (Note 12)	16,785	13,522
Construction financing (Note 13)	21,017	21,017
Dividend payable (Note 27)	11,500	-
Current portion of deferred revenue (Note 17)	1,380	2,628
Current portion of lease liability (Note 9)	130	150
Current portion of long-term debt (Note 14)	6,900	6,537
	68,835	56,628
Non-current		
Post-employment benefits (Note 15)	827	4,252
Contributions in aid of construction (Note 16)	168,893	165,375
Deferred revenue (Note 17)	17,319	17,015
Lease liability (Note 9)	135	98
Derivative related liability (Note 26)	-	2,479
Long-term debt (Note 14)	178,051	167,037
Total liabilities	**434,060**	412,884
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
Contributed surplus	15,968	15,968
Retained earnings	94,796	82,684
Total equity	**149,764**	137,652
Total liabilities and equity	**583,824**	550,536
Regulatory deferral account credit balances (Note 10(b))	23,008	16,199
Total liabilities, equity and regulatory deferral account credit balances	**$ 606,832**	$ 566,735

Commitments and Contingencies (Notes 23 and 24)
The accompanying notes are an integral part of these financial statements.

Approved by the Board

_______________, Chair _______________, Director

6

Yukon Energy Corporation

Statement of Operations and Other Comprehensive Income

(in thousands of Canadian dollars)

For the year ended December 31	2022	2021
Revenues		
Sales of power (Note 18)	$ 80,520	$ 78,633
Other (Note 19)	3,907	4,822
	84,427	83,455
Operating expenses		
Operations and maintenance (Note 20)	35,178	34,018
Depreciation and amortization (Notes 7, 8 and 9)	14,229	13,873
Administration (Note 21)	14,856	13,653
	64,263	61,544
Income before other income and other expenses	**20,164**	21,911
Other income		
Amortization of contributions in aid of construction (Note 16)	3,262	3,080
Allowance for funds used during construction	1,060	942
Unrealized gain on interest rate swap (Note 26)	7,387	2,571
	11,709	6,593
Other expenses		
Interest on borrowings	5,527	5,316
	5,527	5,316
Net income for the year before net movement in regulatory deferral account balances	**26,346**	23,188
Net movement in regulatory deferral account balances related to net income (Note 10(d))	(6,100)	(9,658)
Net income for the year and net movement in regulatory deferral account balances	**20,246**	13,530
Other comprehensive income (Note 3(o))		
Item that will not be reclassified to net income in subsequent periods		
Re-measurement of defined benefit pension plans (Note 15)	3,366	4,905
Total comprehensive income for the year	**$ 23,612**	$ 18,435

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	$	Contributed surplus	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at December 31, 2020	**3,900**	**$ 39,000**	**$ 15,968**	**$ 64,249**	**$ -**	**$ 119,217**
Net income for the year and net movement in regulatory deferral account balances	-	-	-	13,530	-	13,530
Other comprehensive income	-	-	-	-	4,905	4,905
Transfer of re-measurement of defined benefit pension plans to retained earnings	-	-	-	4,905	(4,905)	-
Balance at December 31, 2021	**3,900**	**$ 39,000**	**$ 15,968**	**$ 82,684**	**$ -**	**$ 137,652**
Net income for the year and net movement in regulatory deferral account balances	-	-	-	20,246	-	20,246
Other comprehensive income	-	-	-	-	3,366	3,366
Transfer of re-measurement of defined benefit pension plans to retained earnings	-	-	-	3,366	(3,366)	-
Dividends (Note 27)	-	-	-	(11,500)	-	(11,500)
Balance at December 31, 2022	**3,900**	**$ 39,000**	**$ 15,968**	**$ 94,796**	**$ -**	**$ 149,764**

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	**2022**	**2021**
Operating activities		
Cash receipts from customers	$ 80,096	$ 79,086
Cash receipts from contributions in aid of construction	3,683	19,029
Cash paid to suppliers	(36,690)	(35,487)
Cash paid to employees	(14,212)	(12,817)
Cash receipts from insurance claim settlement	2,137	3,762
Interest paid	(5,669)	(5,302)
Cash provided by operating activities	**29,345**	48,271
Financing activities		
Net (repayments to) advances from line of credit	(1,694)	15,878
Proceeds from long-term debt	17,991	7,659
Repayment of long-term debt	(6,614)	(6,421)
Lease payments	(1,172)	(168)
Cash provided by financing activities	**8,511**	16,948
Investing activities		
Additions to property, plant and equipment	(34,888)	(27,407)
Additions to intangible assets	(3,011)	(2,779)
Cash used in investing activities	**(37,899)**	(30,186)
Net (decrease) increase in cash	(43)	35,033
Cash, beginning of year	**3,104**	(31,929)
Cash, end of year (Note 11)	**$ 3,061**	$ 3,104

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 2022

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 ("the Government" or "YG"). The Utility generates, purchases, transmits, distributes and sells electrical energy in the Yukon. The Utility is not subject to income taxes. The Utility's principal place of business is located at #2 Miles Canyon Road, Whitehorse, Yukon, Y1A 6S7.

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 has assessed that 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*. 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. 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. 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 Government 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 expects it will incur to provide electricity to its customers over the forecast years 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 property, plant and equipment (personnel and materials);
- the cost associated with the depreciation and amortization of property, plant and equipment, right-of-use assets and intangible assets; and
- the return on rate base (the borrowing costs related to borrowing that portion of rate base which is financed with debt plus the costs to provide a reasonable rate of return on that portion of 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: wholesale, general service, industrial, residential, sentinel and street lights and secondary sales. 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 2022

1. NATURE OF OPERATIONS - continued

b) Rate regulation - continued

In November 2020, the Utility filed a GRA for the year 2021 requesting approval of revenue requirement and related rate increase of 11.54%. The YUB issued an order in March 2022 requiring the Utility to make changes and complete a Compliance Filing. The Utility submitted the Compliance Filing in April 2022. The YUB approved the Compliance Filing, as submitted, in July 2022, resulting in an overall rate increase of 9.04%.

Notwithstanding the Compliance Filing process, in April 2022, the Utility filed an Application for Review and Variance of the YUB order issued in March 2022. The Utility disagreed with the YUB's decision on risk premium and disallowance of certain project costs. In August 2022, the YUB agreed to consider changes to the risk premium but not the disallowed project costs. In January 2023, the YUB approved a change to the Utility's risk premium resulting in an increase to return on equity to 8.65% from 8.20% and directed the Utility to prepare a Compliance Filing. The Utility submitted the Compliance Filing in January 2023, and in February 2023 the YUB approved the Compliance Filing, resulting in an adjusted overall rate increase of 9.63%.

Refer to Note 4 Regulatory deferral account balances.

c) Water regulation

The Yukon Water Board ("YWB"), pursuant to the Yukon *Waters Act*, decides if and for how long the Utility will have water licences for the purposes of operating hydro generation stations in the Yukon. The licences will also indicate terms and conditions for the operation of these facilities. The current water licences have the following terms:

Aishihik Generating Station	December 31, 2027
Mayo Generating Station	December 31, 2025
Whitehorse Generating Station	December 31, 2025

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 27). When dividends are declared to the Parent, they may be loaned back in order to maintain this ratio.

2. BASIS OF PRESENTATION

a) Statement of compliance

These financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”).

These financial statements were authorized for issue by the Board of Directors on May 10, 2023.

b) Basis of measurement

The financial information included in the financial statements has been prepared on a historical cost basis, except where otherwise indicated.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2022

3. SIGNIFICANT ACCOUNTING POLICIES

a) Revenue recognition
The Utility recognizes revenue from contracts where the right to consideration from a customer corresponds directly with the value to the customer of the Utility's performance completed to date.

The majority of the Utility's revenues from contracts with customers are derived from the generation, purchase, transmission, distribution, and sales of electricity under the *Public Utilities Act*. The Utility evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and on an ongoing basis if there is an indication of a significant change in facts and circumstances. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when control over a promised good or service is transferred to the customer and the Utility is entitled to consideration as a result of completion of the performance obligation.

The Utility recognizes a contract asset or deferred revenue for the contracts where the performance obligation has not been satisfied. Deferred revenue is recognized when the Utility receives consideration before the performance obligations have been satisfied. A contract asset is recognized when the Utility has rights to consideration for the completion of a performance obligation when that right is conditional on something other than the passage of time. The Utility recognizes unconditional rights to consideration separately as a trade receivable. Contract assets are evaluated at each reporting period to determine whether there is any objective evidence that they are impaired.

The Utility receives amounts from customers for connection to the grid. The customer contributions related to the provision of on-going access to electricity are recognized into revenue over the useful life of the asset to which the contribution relates. The amounts received from Independent Power Producers ("IPPs") in accordance with an Electricity Purchase Agreement ("EPA") are recognized into revenue as the Utility provides the construction activities of the related connection.

Electricity sales contracts are deemed to have a single performance obligation as the promise to transfer individual goods or services is not separately identifiable from other obligations in the contracts and therefore not distinct. These performance obligations are considered to be satisfied over time as electricity is delivered because of the continuous transfer of control to the customer. The method of revenue recognition for the electricity is an output method, which is based on the volume delivered to the customer.

The Utility's electricity sales are calculated based on the customer's usage of electricity during the period at the applicable published rates for each customer class. Electricity rates in the Yukon are set by the YUB. Electricity sales include an estimate of electricity deliveries not yet billed at period-end. The estimated unbilled revenue is based on estimated consumption and applicable rates for the period between the last billing date and the end of the period.

b) 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.

c) Allowance for funds used during construction
The cost of the Utility's property, plant and equipment and intangible assets includes an allowance for funds used during construction ("AFUDC"). The AFUDC rate is based on the Utility's weighted average cost of debt.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2022

3. SIGNIFICANT ACCOUNTING POLICIES - continued

d) Cash
Cash is comprised of bank account balances (net of outstanding cheques).

e) Inventories
Inventories consist of materials and supplies, diesel fuel and liquefied natural gas. Inventories are carried 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 recognized in the Utility's 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.

f) 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.

i) Financial assets

Cash and accounts receivable, plus any transaction costs that are directly attributable to the acquisition of the financial asset, are initially measured at fair value. Subsequent to initial recognition, cash is measured at amortized cost and accounts receivable are measured at amortized cost using the effective interest rate method less any impairment. The Utility's business model is to hold these assets to collect contractual cash flows.

A provision for impairment of accounts receivable is established applying the expected credit loss model based on all possible default events over the expected life of the financial asset. For trade accounts receivable, the Utility applies the simplified approach which requires expected lifetime losses to be recognized from initial recognition of the receivables. For other receivables, at the reporting date, if credit risk has increased significantly since initial recognition, the Utility measures the loss allowance at an amount equal to the lifetime expected credit losses, otherwise, if the credit risk has not increased significantly since initial recognition, the Utility measures the loss allowance at an amount equal to 12-month expected credit losses.

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. A financial asset is derecognized when the rights to receive cash flows from the asset have expired, or the Utility has transferred its rights to receive cash flows from the asset and has transferred substantially all the risk and rewards of the asset.

Derivative financial instruments are financial contracts that derive their value from changes in an underlying variable. The Utility has entered into interest rate swaps to manage interest rate risk. The Utility's interest rate swaps are classified as fair value through profit and loss and are 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.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2022

3. SIGNIFICANT ACCOUNTING POLICIES - continued

f) Financial instruments - continued

ii) Financial liabilities

Bank indebtedness, accounts payable and accrued liabilities, construction financing and long-term debt are initially measured at fair value less any transaction costs that are directly attributable to the issuance of the financial liability. Subsequent to initial recognition, these financial liabilities are measured at amortized cost using the effective interest method.

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.

A financial liability is derecognized when the obligation is discharged or cancelled, or expires.

g) 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 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 recognized as construction work-in-progress until they are operational and available for use, at which time they are transferred to the applicable component of 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	20 to 103 years
Thermal plants	12 to 72 years
Transmission	12 to 65 years
Distribution	16 to 55 years
Buildings	20 to 55 years
Transportation	8 to 25 years
Other equipment	5 to 20 years

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2022

3. SIGNIFICANT ACCOUNTING POLICIES - continued

g) Property, plant and equipment - continued

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.

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 2 to 10 years. Repairs and maintenance costs of property, plant and equipment are expensed as incurred unless they meet the criteria of a betterment.

h) 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 commences when an asset is available for use. Licenses are available for use when the license period commences. 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
Licensing costs	
Aishihik	5 years
Other hydro generation	17 to 25 years
Thermal generation	3 years

i) Leases
At inception of a contract, the Utility assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset. The Utility assesses whether:

- The contract involves the use of an identified asset;
- The Utility has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use; and
- The Utility has the right to direct the use of the asset.

At inception, the Utility allocates the consideration in the contract to each lease component on the basis of the relative stand-alone prices.

The Utility recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability and any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The Utility elected to exclude short-term leases with a term of twelve months or less as well as leases of low-value assets, and accounts for the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2022

3. SIGNIFICANT ACCOUNTING POLICIES - continued

i) Leases - continued

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those property, plant and equipment. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liability. Right-of-use assets are tested for impairment in accordance with IAS 36, *Impairment of Assets*, and impairments are recorded in net income.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Utility's incremental borrowing rate. Generally, the Utility uses its incremental borrowing rate as the discount rate. Subsequent to recognition, the lease liability is measured at amortized cost using the effective interest rate method. A lease liability is remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, or if the Utility changes its assessment of whether it will exercise a renewal or termination option. When the lease liability is remeasured, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in net income if the carrying amount of the right-of-use assets has been reduced to zero.

j) Impairment of non-financial assets
Property, plant and equipment, 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"). 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 account 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 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 2022

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. 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 changes in the regulatory deferral account balances in the net movement in regulatory deferral account balances in the Statement of Operations and Other Comprehensive Income. The amounts recognized as regulatory deferral account balances are expected to be recovered or refunded in future rates, based on approvals by the YUB. 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 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, *Regulatory Deferral Accounts*, 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 performance obligations are met.

Note 10 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 recognized 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 2022

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.

n) Contributions in aid of construction
Certain property, plant and equipment additions are made with financial 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 basis of the life of the asset to which they relate.

o) Post-employment benefits and other comprehensive income
The Utility sponsors an employee defined benefit pension plan for employees joining the Utility before January 1, 2002. The Utility also sponsors an executive defined benefit pension plan and supplemental executive retirement plan for a former executive. Benefits provided are calculated based on length of pensionable service, pensionable salary at retirement age and negotiated rates. The Utility contributes amounts to the pension plans as recommended by an independent actuary.

For the defined benefit plans 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. Re-measurements 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.

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. The Utility has no legal or constructive obligation to pay further contributions with respect to this plan. Contributions are recognized as an expense in the year when employees have rendered service and represent the obligation of the Utility.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2022

4. 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.

Areas of significant judgment and estimates made by management in preparing these financial statements include:

Impairment of non-financial assets – Note 3(j)
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 judgments and assessments about conditions and events in order to conclude whether possible impairment exists.

Asset retirement obligations – Notes 3(l) and 24
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.

Depreciation – Notes 3(g), 7 and 9
Significant components of property, plant and equipment are depreciated straight line over their estimated useful lives. Useful lives are determined based on current facts and past experience and the results of 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 the period of disposition.

Intangible assets – Notes 3(h) and 8
In determining whether to recognize costs as intangible assets, management makes judgments about when the criteria for recognition are met. Management also makes judgments about which costs in work-in-progress pertain to a particular new license because licensing activities occur on a continuing basis. Changes to management's judgments would affect the carrying amount of the Utility's intangible assets and amortization recognition.

Post-employment benefits – Notes 3(o) and 15
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. 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. The Utility consults with qualified actuaries when setting the assumptions used to estimate benefit obligations. Actual rates could vary significantly from the assumptions and estimates used.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2022

4. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS - continued

Revenue – Notes 3(a), 18 and 19
The Utility estimates usage not yet billed at year end, which is included in revenues from sales 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 judgment to the measurement of the estimated consumption. Significant judgments have also been made in determining the nature of the Utility's performance obligations, the appropriate measurement and the contract terms to be used in recognizing the related revenue.

Provisions and Contingencies – Notes 3(m) and 24
Management is required to make judgments to assess if the criteria for recognition of provisions and contingencies are met, in accordance with IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*.

Key judgments are whether a present obligation exists and the probability of an outflow being required to settle that obligation. Key assumptions in measuring provisions include the timing and amount of future payments and the discount rate applied.

Where the Utility is defending certain lawsuits management must make judgments, estimates and assumptions about the final outcome, timing of trial activities and future costs as at the period end date. Management will obtain the advice of its external counsel in determining the likely outcome and estimating the expected obligations associated with these lawsuits; however, the ultimate outcome or settlement costs may differ from management's estimates.

Financial Instruments – Notes 3(f) and 26
The Utility enters into financial instrument arrangements which may require management to make judgments to determine if such arrangements are derivative instruments in their entirety or contain embedded derivatives, in accordance with IFRS 9, *Financial Instruments*. Key judgments are whether certain non-financial items are readily convertible to cash, whether similar contracts are routinely settled net in cash or delivery of the underlying commodity taken and then resold within a short period, and whether the value of a contract changes in response to a change in an underlying rate, price, index or other variable.

Regulatory deferral account balances – Notes 1(b), 3(k) and 10
The Utility accounts for its regulatory deferral accounts in accordance with IFRS 14 and the decisions of the YUB. As discussed in Note 1(b) the recovery of these balances will be determined by the YUB as part of the regulatory proceeding to approve the GRA. Management is required to make judgments about the extent that the Utility will be permitted to incorporate deferred amounts in future rates.

Yukon Energy Corporation

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5. ACCOUNTS RECEIVABLE

	December 31 2022	December 31 2021
Trade accounts receivable		
Retail energy sales	$ 8,426	$ 5,146
Wholesale energy sales	6,404	6,171
Due from related parties (Note 22)	4,353	1,256
Other	1,221	3,550
	$ 20,404	$ 16,123

Included in Accounts receivable - Other is an amount of $0 (2021 - $2,137,000) related to insurance proceeds (Note 19).

At December 31, 2022, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	$ 15,447	$ 3,262	$ 1,705	$ 20,414
Allowance for doubtful accounts	-	-	(10)	(10)
	$ 15,447	$ 3,262	$ 1,695	$ 20,404

At December 31, 2021, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	$ 14,606	$ 1,254	$ 273	$ 16,133
Allowance for doubtful accounts	-	-	(10)	(10)
	$ 14,606	$ 1,254	$ 263	$ 16,123

A reconciliation of the beginning and ending amount of allowance for doubtful accounts is as follows:

	December 31 2022	December 31 2021
Allowance for doubtful accounts at beginning of year	$ (10)	$ (10)
Amounts written off as uncollectable	-	-
Allowance for doubtful accounts at end of year	$ (10)	$ (10)

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6. INVENTORIES

	December 31 2022	December 31 2021
Materials and supplies	$ 3,562	$ 3,488
Diesel fuel	1,312	750
Liquefied natural gas	70	116
	$ 4,944	$ 4,354

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 & Other Equipment	Transportation	Construction Work-in Progress	Total
Cost:						
At December 31, 2020	$ 310,372	$ 200,147	$ 20,893	$ 5,700	$ 24,722	$ 561,834
Additions	-	-	-	-	26,425	26,425
Transfers	15,284	31,074	981	-	(47,339)	-
Disposals	(880)	(1,095)	(114)	(216)	-	(2,305)
At December 31, 2021	$ 324,776	$ 230,126	$ 21,760	$ 5,484	$ 3,808	$ 585,954
Additions	-	-	-	-	39,469	39,469
Transfers	6,979	6,086	624	525	(14,214)	-
Disposals	(1,313)	(8)	(407)	(209)	-	(1,937)
At December 31, 2022	$ 330,442	$ 236,204	$ 21,977	$ 5,800	$ 29,063	$ 623,486
Accumulated depreciation:						
At December 31, 2020	$ 38,849	$ 33,894	$ 5,189	$ 2,009	$ -	$ 79,941
Depreciation	6,791	4,447	710	565	-	12,513
Disposals	(69)	(175)	(106)	(152)	-	(502)
At December 31, 2021	$ 45,571	$ 38,166	$ 5,793	$ 2,422	$ -	$ 91,952
Depreciation	6,882	4,695	724	616	-	12,917
Disposals	(1,313)	(3)	(378)	(161)	-	(1,855)
At December 31, 2022	$ 51,140	$ 42,858	$ 6,139	$ 2,877	$ -	$ 103,014
Net book value:						
At December 31, 2021	$ 279,205	$ 191,960	$ 15,967	$ 3,062	$ 3,808	$ 494,002
At December 31, 2022	$ 279,302	$ 193,346	$ 15,838	$ 2,923	$ 29,063	$ 520,472

The total AFUDC capitalized for 2022 was $1,060,000 (2021 - $942,000). The AFUDC rate estimate for 2022 was 2.61% (2021 - 2.60%).

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8. INTANGIBLE ASSETS

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Software	Deferred Service Costs	Financial Software	Aishihik Water Licensing	Thermal and Other Water Licensing	Total
Cost:						
At December 31, 2020	$ 1,686	$ 443	$ 6,187	$ 8,544	$ 4,432	$ 21,292
Additions	133	-	793	1,616	121	2,663
Disposals	(516)	-	-	-	-	(516)
At December 31, 2021	$ 1,303	$ 443	$ 6,980	$ 10,160	$ 4,553	$ 23,439
Additions	284	-	75	1,314	2,231	3,904
Transfers	-	-	-	(343)	343	-
Disposals	(396)	-	-	(805)	-	(1,201)
At December 31, 2022	$ 1,191	$ 443	$ 7,055	$ 10,326	$ 7,127	$ 26,142
Accumulated amortization:						
At December 31, 2020	$ 936	$ 443	$ 1,986	$ 299	$ 192	$ 3,856
Amortization	237	-	628	306	33	1,204
Disposals	(516)	-	-	-	-	(516)
At December 31, 2021	$ 657	$ 443	$ 2,614	$ 605	$ 225	$ 4,544
Amortization	235	-	554	306	33	1,128
Disposals	(396)	-	-	(805)	-	(1,201)
At December 31, 2022	$ 496	$ 443	$ 3,168	$ 106	$ 258	$ 4,471
Net book value:						
At December 31, 2021	$ 646	$ -	$ 4,366	$ 9,555	$ 4,328	$ 18,895
At December 31, 2022	$ 695	$ -	$ 3,887	$ 10,220	$ 6,869	$ 21,671

Additions to Financial Software, Aishihik Water Licensing and Thermal and Water Licensing for 2022 and 2021 were almost exclusively internally generated. Additions to Software was almost exclusively externally purchased.

Work-in-progress, which is included in cost, is as follows: Aishihik Water Licensing $10,214,000 (2021 – $9,243,000) and Thermal and Other Water Licensing $6,756,000 (2021 - $4,182,000). These amounts represent costs related to license renewals which are not yet in effect. The Aishihik Water License that expires December 31, 2027 (Note 1(c)) became effective January 1, 2023.

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9. LEASES

The Utility leases industrial land and building facilities During the year the Utility commenced a land lease for the Energy Storage System for a term of twenty-five years. The Utility paid the lease in full during the year.

Right-of-use assets consist of land of $1,139,000 (2021 - $20,000) and building of $92,000 (2021 - $214,000).

	December 31 2022	December 31 2021
Right-of-use assets		
As at January 1	$ 234	$ 390
Additions	1,181	-
Depreciation expense	(184)	(156)
As at December 31	$ 1,231	$ 234
Lease liabilities		
Lease liabilities	$ 265	$ 248
Less: current portion	130	150
Non-current portion	$ 135	$ 98
Maturity analysis		
Less than one year	$ 137	$ 156
One to five years	145	99
More than five years	-	-
Total undiscounted lease liabilities	$ 282	$ 255
Amounts recognized in net income		
Depreciation expense on right-of-use assets	$ (184)	$ (156)
Interest expense on lease liabilities	$ (8)	$ (11)
Expense relating to short-term leases	$ (3,203)	$ (3,946)

Yukon Energy Corporation

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10. REGULATORY ACCOUNTS

a) Regulatory deferral account debit balances

	Feasibility Studies (i)	Regulatory Costs (ii)	Dam Safety (iii)	Deferred Overhauls (iv)	Uninsured Losses (v)	Fuel Price Adjustment (vi)	Subtotal see next page
Cost:							
At December 31, 2020	$ 24,770	$ 6,751	$ 322	$ 2,768	$ 2,604	$ 2,257	$ 39,472
Costs incurred	1,343	1,789	81	-	3,654	-	6,867
Regulatory provision	-	-	-	-	(411)	1,557	1,146
Disposals	(4,450)	(598)	(148)	-	(104)	(2,491)	(7,791)
Contributions received/receivable	-	(279)	-	-	(2,737)	-	(3,016)
At December 31, 2021	$ 21,663	$ 7,663	$ 255	$ 2,768	$ 3,006	$ 1,323	$ 36,678
Costs incurred	115	2,380	-	-	2,006	-	4,501
Regulatory provision	-	(903)	-	390	(411)	3,705	2,781
Disposals	(4,971)	(493)	-	(1,759)	-	(1,863)	(9,086)
Contributions received	-	(263)	-	-	-	-	(263)
At December 31, 2022	$ 16,807	$ 8,384	255	$ 1,399	$ 4,601	$ 3,165	$ 34,611
Accumulated amortization:							
At December 31, 2020	$ 8,793	$ 1,056	$ 118	$ 1,270	$ 848	$ -	$ 12,085
Amortization	2,168	414	55	581	204	-	3,422
Disposals	(4,450)	(598)	(148)	-	-	-	(5,196)
At December 31, 2021	$ 6,511	$ 872	$ 25	$ 1,851	$ 1,052	$ -	$ 10,311
Amortization	1,491	295	51	18	205	-	2,060
Disposals	(4,963)	-	-	(1,759)	-	-	(6,722)
At December 31, 2022	$ 3,039	$ 1,167	$ 76	$ 110	$ 1,257	$ -	$ 5,649
Net book value:							
At December 31, 2021	$ 15,152	$ 6,791	$ 230	$ 917	$ 1,954	$ 1,323	$ 26,367
At December 31, 2022	$ 13,768	$ 7,217	$ 179	$ 1,289	$ 3,344	$ 3,165	$ 28,962
Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement in regulatory deferral account balances related to net income on the Statement of Operations and Other Comprehensive Income):							
December 31, 2021	$ (825)	$ 1,096	$ 26	$ (581)	$ 198	$ (934)	$ (1,020)
December 31, 2022	$ (1,384)	$ 426	$ (51)	$ 372	$ 1,390	$ 1,842	$ 2,595
Remaining recovery years							
At December 31, 2021	1 to 5 years	1 to 32 years	5 years	1 to 5 years	Indeterminate	1 year	
At December 31, 2022	1 to 5 years	1 to 31 years	4 years	5 to 10 years	Indeterminate	1 year	
Absent rate regulation, net income for the year and net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:							
December 31, 2021	$ 825	$ (1,096)	$ (26)	$ 581	$ (198)	$ 934	$ 1,020
December 31, 2022	$ 1,384	$ (426)	$ 51	$ (372)	$ (1,390)	$ (1,842)	$ (2,595)

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2022

10. REGULATORY ACCOUNTS - continued

a) Regulatory deferral account debit balances - continued

	Carry Forward	Vegetation Management (vii)	2017/18 GRA (viii)	2021 GRA (ix)	IPP Purchase Costs (x)	Total
Cost:						
At December 31, 2020	$ 39,472	$ 2,216	$ 5,897	$ -	$ -	$ 47,585
Costs incurred	6,867	-	-	-	-	6,867
Regulatory provision	1,146	-	-	8,779	-	9,925
Disposals	(7,791)	-	(5,897)	(4,449)	-	(18,137)
Contributions received	(3,016)	-	-	-	-	(3,016)
At December 31, 2021	$ 36,678	$ 2,216	$ -	$ 4,330	$ -	$ 43,224
Costs incurred	4,501	-	-	-	26	4,527
Regulatory provision	2,781	-	-	2,269	-	5,050
Disposals	(9,086)	-	-	(3,960)	-	(13,046)
Contributions received	(263)	-	-	-	-	(263)
At December 31, 2022	$ 34,611	$ 2,216	$ -	$ 2,639	$ 26	$ 39,492
Accumulated amortization:						
At December 31, 2020	$ 12,085	$ 887	$ -	$ -	$ -	$ 12,972
Amortization	3,422	222	5,897	4,449	-	13,990
Disposals	(5,196)	-	(5,897)	(4,449)	-	(15,542)
At December 31, 2021	$ 10,311	$ 1,109	$ -	$ -	$ -	$ 11,420
Amortization	2,060	221	-	3,960	-	6,241
Disposals	(6,722)	-	-	(3,960)	-	(10,682)
At December 31, 2022	$ 5,649	$ 1,330	$ -	$ -	$ -	$ 6,979
Net book value:						
At December 31, 2021	$ 26,367	$ 1,107	$ -	$ 4,330	$ -	$ 31,804
At December 31, 2022	$ 28,962	$ 886	$ -	$ 2,639	$ 26	$ 32,513
Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income):						
December 31, 2021	$ (1,020)	$ (222)	$ (5,897)	$ 4,330	$ -	$ (2,809)
December 31, 2022	$ 2,595	$ (221)	$ -	$ (1,691)	$ 26	$ 709
Remaining recovery years						
At December 31, 2021		5 years	N/A	2 years	N/A	
At December 31, 2022		4 years	N/A	1 year	Indeterminate	
Absent rate regulation, net income for the year and net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:						
December 31, 2021	$ 1,020	$ 222	$ 5,897	$ (4,330)	$ -	$ 2,809
December 31, 2022	$ (2,595)	$ 221	$ -	$ 1,691	$ (26)	$ (709)

(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. The Utility is directed to defer and amortize the costs over terms (between five and ten years) at the discretion of the YUB. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2022

10. REGULATORY ACCOUNTS - continued

a) Regulatory deferral account debit balances - continued

(ii) 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 and demand side management costs (consumer energy conservation program). The Utility is directed to defer and amortize the costs over terms at the discretion of the YUB. As part of the 2021 GRA, $903,000 was transferred to the regulatory deferral account credit balance class hearing reserve (Note 10(b)(ii)) and disallowed costs of $493,000 were derecogized. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(iii) 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. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(iv) Deferred overhauls
YUB Order 2013-01 restricted inclusion of property, plant and equipment overhaul depreciation expense in rates charged to customers until the Utility comes before the YUB for a prudence review. As such, starting in 2013 the Utility deferred depreciation expense related to overhauls. In 2017, the Utility came before the YUB for a prudence review and began to recognize these deferred depreciation amounts. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(v) Uninsured losses
Uninsured losses is an account maintained to address uninsured and uninsurable losses as well as the deductible portion of insured losses. The account is maintained through an annual provision and collected through customer rates. There is an annual regulatory provision of $411,000 (2021 - $411,000) and amortization of the forecast 2020 accumulated balance of $2,048,000 over ten years ($205,000 per year). Costs incurred of $2,006,000 (2021 - $3,654,000) include $0 (2021 - $2,445,000) for repairs required at the WH1 and WH2 penstocks and $425,000 (2021 - $0) to conduct a survey on the Mayo penstock to confirm no damage in order to reduce the insurance deductible that had increased resulting from the damage to the Whitehorse penstocks. The Utility received $0 (2021 - $2,368,000) insurance proceeds. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred and the expected insurance proceeds recognized as revenue.

(vi) 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 long-term average prices is deferred and recovered from or refunded to customers in a future period through Rider F. As part of the 2021 GRA, the balance as at December 31, 2021 of $1,323,000 was transferred to the regulatory deferral account debit balance class 2021 GRA (Note 10(a)(ix)). For the period January 1, 2021 through June 30, 2021 the charge was 1.371 cents per kWh. For the period July 1, 2021 to July 31, 2022, the charge was reduced to 0.000 cents per kWh. Effective August 1, 2022, the charge was increased to 0.865 cents per kWh. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred and revenues be recognized as earned.

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10. REGULATORY ACCOUNTS - continued

a) Regulatory deferral account debit balances - continued

(vii) Vegetation management
Prior to 2017, the Utility was deferring annual brushing costs in excess of a prescribed maximum annual amount based on a review of prior year brushing costs. In 2017, the Utility established a vegetation management policy and as a result of expected annual costs, deferral is no longer required. The Utility completes a full cycle of all of its brushing requirements every 10 years and is amortizing previously deferred costs over a 10 year period. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(viii) 2017/18 GRA
The Utility recognizes a regulatory deferral account debit balance when the Utility has the right, as a result of the actual or expected actions of the rate regulator, to increase rates in future periods in order to recover its allowable costs plus return on rate base, as described in Note 1(b). The amount recognized represents the amount approved by the YUB in November 2019, less amounts subsequently received from customers. At December 31, 2021 the amount was fully collected.

(ix) 2021 GRA
The Utility recognizes a regulatory deferral account debit balance when the Utility has the right, as a result of the actual or expected actions of the rate regulator, to increase rates in future periods in order to recover its allowable costs plus return on rate base, as described in Note 1(b). The amount recognized represents management's best estimates of revenues for rates to be approved by the YUB less amounts received from customers. As part of the 2021 GRA, $1,323,000 was transferred from the regulatory deferral account debit class fuel price adjustment (Note 10(a)(vi)) and $1,129,000 was recognized for increase in return on equity. These amounts are reflected in the regulatory provision line. The ending balance at December 31 comprises the Utility's remaining revenue shortfall to be collected from customers in future years.

(x) IPP purchase costs
OIC 2019/25 directs that in setting rates that the Utility is permitted to charge, it is able to recover the costs of purchasing electricity under an electricity purchase agreement with Independent Power Producers ("IPP's"). As such, starting in 2022 the Utility deferred costs to be charged to ratepayers in future years. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

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10. REGULATORY ACCOUNTS - continued

b) Regulatory deferral account credit balances

	Deferred Insurance Proceeds (i)	Hearing Reserve (ii)	Low Water Reserve Fund (iii)	Future Removal and Site Restoration (iv)	Contracts with Customers (v)	McQuesten Substation (vi)	Subtotal see next page
Cost:							
At December 31, 2020	$ 11,602	$ 596	$ (2,511)	$ 2,739	$ 5,126	$ -	$ 17,552
Cost incurred	-	(101)	-	-	-	-	(101)
Regulatory provision	-	250	5,288	-	30	1,834	7,402
Cash refunded	-	-	5	-	-	-	5
At December 31, 2021	$ 11,602	$ 745	$ 2,782	$ 2,739	$ 5,156	$ 1,834	$ 24,858
Cost incurred	-	-	-	(49)	-	-	(49)
Regulatory provision	-	(653)	7,114	-	(96)	692	7,057
Disposals	-	(973)	-	-	-	-	(973)
At December 31, 2022	$ 11,602	$ (881)	$ 9,896	$ 2,690	$ 5,060	$ 2,526	$ 30,893
Accumulated amortization:							
At December 31, 2020	$ 7,424	$ 778	$ -	$ -	$ -	$ -	$ 8,202
Amortization	262	195	-	-	-	-	457
Disposals	-	-	-	-	-	-	-
At December 31, 2021	$ 7,686	$ 973	$ -	$ -	$ -	$ -	$ 8,659
Amortization	262	-	-	-	-	-	262
Disposals	-	(973)	-	-	-	-	(973)
At December 31, 2022	$ 7,948	$ -	$ -	$ -	$ -	$ -	$ 7,948
Net book value:							
At December 31, 2021	$ 3,916	$ (228)	$ 2,782	$ 2,739	$ 5,156	$ 1,834	$ 16,199
At December 31, 2022	$ 3,654	$ (881)	$ 9,896	$ 2,690	$ 5,060	$ 2,526	$ 22,945
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, 2021	$ 262	$ 46	$ (5,293)	$ -	$ (30)	$ (1,834)	$ (6,849)
December 31, 2022	$ 262	$ 653	$ (7,114)	$ 49	$ 96	$ (692)	$ (6,746)
Remaining recovery years							
At December 31, 2021	15 years	Indeterminate	Indeterminate	Indeterminate	46 years	52 years	
At December 31, 2022	14 years	Indeterminate	Indeterminate	Indeterminate	45 years	51 years	
Absent rate regulation, net income for the year end and net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:							
December 31, 2021	$ (262)	$ (46)	$ 5,293	$ -	$ 30	$ 1,834	$ 6,849
December 31, 2022	$ (262)	$ (653)	$ 7,114	$ (49)	$ (96)	$ 692	$ 6,746

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December 31 2022

10. REGULATORY ACCOUNTS - continued

b) Regulatory deferral account credit balances - continued

	Carry Forward	Defined Benefit Pension (vii)	Total
Cost:			
At December 31, 2020	$ 17,552	$ -	$ 17,552
Cost incurred	(101)	-	(101)
Regulatory provision	7,402	-	7,402
Cash refunded	5	-	5
At December 31, 2021	$ 24,858	$ -	$ 24,858
Cost incurred	(49)	-	(49)
Regulatory provision	7,057	63	7,120
Disposals	(973)	-	(973)
At December 31, 2022	$ 30,893	$ 63	$ 30,956
Accumulated amortization:			
At December 31, 2020	$ 8,202	$ -	$ 8,202
Amortization	457	-	457
Disposals	-	-	-
At December 31, 2021	$ 8,659	-	$ 8,659
Amortization	262	-	262
Disposals	(973)	-	(973)
At December 31, 2022	$ 7,948	$ -	$ 7,948
Net book value:			
At December 31, 2021	$ 16,199	$ -	$ 16,199
At December 31, 2022	$ 22,945	$ 63	$ 23,008
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, 2021	$ (6,849)	$ -	$ (6,849)
December 31, 2022	$ (6,746)	$ (63)	$ (6,809)
Remaining recovery years			
At December 31, 2021		N/A	
At December 31, 2022		Indeterminate	
Absent rate regulation, net income for the year end and net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:			
December 31, 2021	$ 6,849	$ -	$ 6,849
December 31, 2022	$ 6,746	$ 63	$ 6,809

(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 is being amortized to income at the same rate as depreciation of the related replacement assets. In the absence of rate regulation, IFRS requires the gain to have been fully recognized as income in the year received.

(ii) Hearing reserve

The Utility has established a deferral account for regulatory hearing costs to be recovered from or paid to ratepayers in the future. The regulatory provision for the year reflects an annual provision of $250,000 (2021 - $250,000) less $903,000 of approved costs transferred from Regulatory costs (Note 10(a)(ii)). In the absence of rate regulation, IFRS requires these costs to be expensed as incurred and revenues be recognized as earned.

Yukon Energy Corporation

Notes to Financial Statements
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10. REGULATORY ACCOUNTS - continued

b) Regulatory deferral account credit balances - continued

(iii) Low water reserve fund
The Low Water Reserve Account ("LWRF") was established by YUB Order 2018-10. The LWRF is used to protect the Utility and ratepayers for costs associated with variability in thermal generation required when there is a thermal cost variance due solely to water-related hydro generation variances from YUB approved GRA forecasts. The Utility is required to file annual reports with the YUB on the LWRF's activity.

In accordance with YUB Order 2015-01, the Utility defers recognition of the additional amounts collected from rate payers when the cost of thermal consumed in the period is less than the long-term average thermal requirements estimated for the actual annual generation load. These deferred amounts are recognized as revenue in the period when the cost of thermal incurred for the period is greater than the long-term average thermal requirements and the reason for the shortfall is a shortage of water in the hydro system. There is a cap of +/- $16 million for the LWRF. 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. YUB Order 2019-02 set the refund rider to 0.00 cents/kWh effective April 1, 2019.

In the absence of rate regulation, IFRS would require any amounts earned or incurred related to the LWRF to be included in the Utility's net income in the year incurred.

(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 based upon depreciation studies conducted periodically by the Utility. As a result of 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.

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 requires these costs to be expensed or included in the gain or loss on disposal of the related property, plant and equipment, as applicable.

(v) Contracts with customers
Effective January 1, 2018 the Utility adopted IFRS 15, *Revenue from Contracts with Customers*. As a result of the impacts of IFRS 15, certain revenues are recognized in net income over a shorter period than allowed by the YUB for rate-setting purposes. The timing difference is reflected as a regulatory deferral account credit balance.

(vi) McQuesten substation
YUB Order 2022-03 required the Utility to create a separate asset class for certain assets constructed at the McQuesten Substation relating to the Victoria Gold connection. These assets were required to be amortized over the mine life as opposed to the useful life of the assets. The timing difference is reflected as a regulatory deferral account credit balance.

Yukon Energy Corporation

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10. REGULATORY ACCOUNTS - continued

b) Regulatory deferral account credit balances - continued

(vii) Defined benefit pension
The Utility has established a deferral account to accumulate differences from approved pension funding versus actual funding requirements. The regulatory provision will be determined through a future regulatory proceeding. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(c) Regulatory account expenses

Regulatory account expenses represent costs incurred related to regulatory account debit balances of $4,527,000 (2021 - $6,867,000) and regulatory account credit balances of $49,000 (2021 - $101,000).

(d) Net movement in regulatory deferral account balances related to net income

Net movement in regulatory deferral account balances related to net income is $6,100,000 (2021 - $9,658,000) represents the adjustment to 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 is comprised of an increase of $709,000 for regulatory account debit balances and an increase of $6,809,000 for regulatory account credit balances for rate regulation compared to the amounts that are recognized under IFRS. The net movement figure for 2021 is comprised of an decrease of $2,809,000 for regulatory account debit balances and an increase of $6,849,000 for regulatory account credit balances respectively for rate regulation compared to the amounts that would be recorded under IFRS absent rate regulation.

11. BANK INDEBTEDNESS

By agreement the financial institution has a legally enforceable right to set off the outstanding balance under the line of credit by cash balances in other accounts with the same bank. The amount outstanding on the line of credit balance at year end was $14.1 million (2021 - $15.9 million). The Utility has cash balances with the same financial institution of $3.1 million (2021 - $3.1 million). The Utility's bank indebtedness is comprised of:

	December 31 2022	December 31 2021
Line of credit	$ 14,184	$ 15,878
Less: bank balances	3,061	3,104
	$ 11,123	$ 12,774

For the purposes of the statement of cash flows, the line of credit is classified as financing activities. In the statement of cash flows, cash is comprised of bank balances.

Yukon Energy Corporation

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12. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31 2022	December 31 2021
Trade payables	$ 13,951	$ 10,340
Due to related parties (Note 22)	1,422	1,216
Employee compensation	1,151	1,690
Other	261	276
	$ 16,785	$ 13,522

13. CONSTRUCTION FINANCING

	December 31 2022	December 31 2021
Construction financing, due December 31, 2023 bearing interest at 5.19% approved to a maximum of $8.4 million	$ 8,400	$ -
Construction financing, due December 31, 2023 bearing interest at 5.19% approved to a maximum of $14 million	12,617	-
Construction financing, due December 31, 2022 bearing interest at 1.50% approved to a maximum of $8.4 million	-	8,400
Construction financing, due December 31, 2022 bearing interest at 1.50% approved to a maximum of $14 million	-	12,617
	$ 21,017	$ 21,017

Construction financing balances are monies advanced from the Parent to assist in the development of the Utility's infrastructure. Interest is payable annually at December 31 and at the maturity date.

The prior year debt was extinguished and replaced with new debt with no impact on cash flows.

Yukon Energy Corporation

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14. LONG-TERM DEBT

The Utility's long-term debt is unsecured and summarized as follows:

	December 31 2022	December 31 2021
Yukon Development Corporation		
$77,723,273 term note bearing interest at 2.68% repayable in annual installments of $3,683,800 principal, plus accrued interest with the balance of $59,304,273 due December 31, 2024	$ 62,988	$ 66,672
$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 (i)	18,194	18,531
$5,505,000 term note bearing interest at 2.40% interest only payable monthly, due December 31, 2039	5,505	5,505
$20,984,404 term note bearing interest at 2.21%, interest payable monthly repayable in annual installments of $839,376 principal with the balance due December 31, 2040	15,109	15,948
$12,136,000 term note bearing interest at 2.10% interest only payable monthly, due December 31, 2041	12,136	12,136
$2,871,000 term note bearing interest at 2.90% interest only payable monthly, due June 30, 2044	2,871	2,871
$3,958,745 term note bearing interest at 1.56% interest only payable monthly, due June 30, 2025	3,959	3,959
TD Bank		
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 2.06% per annum. Payable in monthly installments of $47,918 interest and principal with the balance due on September 28, 2035 (ii)	7,413	7,831
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptance amounts from a variable interest rate based on the Bankers' Acceptance rates to a fixed rate of 3.40% per annum. Payable in monthly installments of $117,095 interest and principal with the balance due on August 23, 2043 (iii)	20,843	21,527
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptance amounts from a variable interest rate based on the Bankers' Acceptance rates to a fixed rate of 2.64% per annum. Payable in monthly installments of $30,868 interest and principal with the balance due on July 14, 2044 (iv)	6,089	6,295
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptance amounts from a variable interest rate based on the Bankers' Acceptance rates to a fixed rate of 2.06% per annum. Payable in monthly installments of $20,478 interest and principal with the balance due on November 4, 2045 (v)	4,488	4,640
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptance amounts from a variable interest rate based on the Bankers' Acceptance rates to a fixed rate of 2.88% per annum. Payable in monthly installments of $35,853 interest and principal with the balance due on April 30, 2046 (vi)	7,301	7,518

Yukon Energy Corporation

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14. LONG-TERM DEBT - continued

	December 31 2022	December 31 2021
TD Bank - continued		
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptance amounts from a variable interest rate based on the Bankers' Acceptance rates to a fixed rate of 4.07% per annum. Payable in monthly installments of $86,661 interest and principal with the balance due on September 1, 2052 (vii)	$ 17,914	$ -
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, repayment terms not yet established	141	141
Long-term debt	184,951	173,574
Less: current portion	6,900	6,537
	$ 178,051	$ 167,037

(i) $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 5.46% (2021 - 5.46%).

(ii) TD Bank Loan and 2.06% 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. On September 11, 2020, the loan and interest rate swap was amended. The amendment changed the interest rate from 2.69% to 2.06% and the termination date from December 28, 2022 to September 28, 2035.

(iii) TD Bank Loan and 3.40% Interest Rate Swap
On August 23, 2018, 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. On September 11, 2020, the loan and interest rate swap was amended. The amendment changed the interest rate from 3.67% to 3.40% and the termination date from August 23, 2038 to August 23, 2043.

(iv) TD Bank Loan and 2.64% Interest Rate Swap
On July 15, 2019, 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. On September 11, 2020, the loan and interest rate swap was amended. The amendment changed the interest rate from 2.90 % to 2.64% and the termination date from July 14, 2039 to July 14, 2044.

Yukon Energy Corporation

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14. LONG-TERM DEBT - continued

(v) TD Bank Loan and 2.06% Interest Rate Swap
On November 4, 2020, 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 November 4, 2045.

(vi) TD Bank Loan and 2.88% Interest Rate Swap
On April 26, 2021, 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 April 30, 2046.

(vii) TD Bank Loan and 4.07% Interest Rate Swap
On August 29, 2022, 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 September 1, 2052.

Long-term debt repayment
Scheduled repayments for all long-term debt are as follows:

2023	6,900
2024	62,582
2025	7,300
2026	3,408
2027	3,475
Thereafter	101,286
	$ 184,951

The change in long-term debt arising from financing activities during the year related to principal repayments of $6,614,000 (2021 - $6,421,000) and the issuance of additional debt in the amount of $17,991,000 (2021 - $7,659,000).

Fair value
The fair value of long-term debt at December 31, 2022 is $174,539,000 (2021 - $179,328,000). 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

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15. POST-EMPLOYMENT BENEFITS

Characteristics of benefit plans
The Utility sponsors a defined benefit pension plan for employees joining the Utility before January 1, 2002. The Utility also sponsors an executive defined benefit pension plan and supplemental executive retirement 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 pension 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 retirement plan. The costs recognized for the period are equal to the Utility’s contribution to the plan. During 2022, these were $559,000 (2021 - $568,000).

The defined benefit pension plan for employees is regulated by the Office of the Superintendent of Financial Institutions ("OSFI") through the *Pension Benefits Standards Act* and regulations. This Act and accompanying regulations impose, among other things, minimum funding requirements. The executive defined benefit pension plan and supplemental executive retirement plan are not registered with OSFI and are not subject to minimum funding requirements of the Act.

These minimum funding requirements require the Utility to make special payments as prescribed by OSFI to repay any unfunded liability or solvency deficiency that may exist. For the employee defined benefit pension plan the Utility is required to pay $123,900 for 2023. This amount may change in future years and the current requirements are summarized as follows:

Start Date	Minimum Annual Payment	End Date
January 1, 2018	$12,900	December 31, 2032
January 1, 2019	$36,000	December 31, 2033
January 1, 2020	$75,000	December 31, 2034
	$123,900	

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 defined benefit pension plans expose the Utility to risk such as investment risk and actuarial risk. Investment risk is the risk that the assets invested will be insufficient to meet expected benefits. Actuarial risk is the risk that benefits paid will be more than expected. There are no particular unusual, entity-specific or plan-specific risks or any significant concentration of risk.

Yukon Energy Corporation

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15. POST-EMPLOYMENT BENEFITS - continued

Net defined benefit liability

	December 31 2022	December 31 2021
Present value of benefit obligations		
Balance, beginning of year	$ 28,781	$ 31,318
Employee contributions	43	48
Current service cost	409	468
Interest cost	864	785
Benefits paid	(827)	(814)
Actuarial losses (gains) on experience	319	(856)
Actuarial (gains) on demographic assumptions	(6)	-
Actuarial (gains) on financial assumptions	(7,047)	(2,168)
Balance, end of year	$ 22,536	$ 28,781
Fair value of plan assets		
Balance, beginning of year	24,611	22,247
Interest income on plan assets	736	554
(Losses) gains on plan assets	(3,376)	1,963
Employee contributions	43	48
Employer contributions	668	681
Benefits paid	(827)	(814)
Administrative costs	(70)	(68)
Balance, end of year	$ 21,785	$ 24,611
Effect of asset ceiling	76	82
Net defined benefit liability	$ 827	$ 4,252

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2022

15. POST-EMPLOYMENT BENEFITS - continued

Components of benefit plan cost:

	December 31 2022	December 31 2021
Current service cost	$ 409	$ 468
Interest cost	864	785
Interest income on plan assets	(736)	(554)
Administrative costs	70	68
Interest cost on effect of asset ceiling	2	-
Defined benefit expense in Statement of Operations	609	767
Defined contribution expense	559	568
Total benefit expense in Statement of Operations	$ 1,168	$ 1,335
Actuarial (gains) on obligation	(6,734)	(3,024)
Losses (gains) on plan assets	3,376	(1,963)
Effect of asset ceiling	(8)	82
Total re-measurements included in Other Comprehensive Income	$ (3,366)	$ (4,905)
Total benefit costs recognized in Statement of Operations and Other Comprehensive Income	$ (2,198)	$ (3,570)

Distribution of plan assets of defined benefit pension plans
The fair value of the defined benefit pension plans' assets are based on market values as reported by the defined benefit pension plans' custodians as at each applicable Statement of Financial Position date. The distribution of assets by major asset class is as follows:

	December 31, 2022	December 31, 2021
Equities	43.8%	42.6%
Fixed income securities	31.5%	36.5%
Real estate	24.7%	20.9%

Significant assumptions:

	December 31, 2022	December 31, 2021
Discount rate - accrued benefit obligation	5.10%	3.00%
Assumed rate of compensation increase	3.10%	2.80%
Pension growth	2.00%	2.00%

Yukon Energy Corporation

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15. POST-EMPLOYMENT BENEFITS - continued

Sensitivity analysis of the defined benefit pension plans:
The sensitivities of each key assumption used in measuring accrued benefit obligations at each Statement of Financial Position date 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 MI-2017.

Assumptions and sensitivity to the recognized post-employment benefits liability balance at December 31, 2022

Assumption	+1%	-1%	+1%	-1%
Discount rate	-11%	13%	$ (2,431)	$ 2,965
Salary growth	0.4%	-0.4%	80	(77)
Pension growth	13%	-11%	2,813	(2,357)
Life expectancy (1 year movement)	2%	-2%	517	(529)

Assumptions and sensitivity to the recognized post-employment benefits liability balance at December 31, 2021

Assumption	+1%	-1%	+1%	-1%
Discount rate	-13%	16%	$ (3,758)	$ 4,714
Salary growth	1%	-1%	156	(149)
Pension growth	15%	-12%	4,226	(3,472)
Life expectancy (1 year movement)	3%	-3%	830	(836)

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 employee benefit 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 12.1 years (2021 - 14.9 years). The Utility expects to make payments of $230,800 (2021 - $606,800) to the defined benefit plans during the next financial year.

Yukon Energy Corporation

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16. CONTRIBUTIONS IN AID OF CONSTRUCTION

	Government of Canada	Parent since 1998	Yukon Government since 1998	Pre-1998 contributions	Total
Cost:					
At December 31, 2020	$ 83,694	$ 89,730	$ 11,698	$ 1,739	$ 186,861
Additions	9,266	-	200	-	9,466
At December 31, 2021	$ 92,960	$ 89,730	$ 11,898	$ 1,739	$ 196,327
Additions	6,780	-	-	-	6,780
At December 31, 2022	$ 99,740	$ 89,730	$ 11,898	$ 1,739	$ 203,107
Accumulated amortization:					
At December 31, 2020	$ 8,993	$ 14,651	$ 2,720	$ 1,508	$ 27,872
Amortization	1,204	1,604	228	44	3,080
At December 31, 2021	$ 10,197	$ 16,255	$ 2,948	$ 1,552	$ 30,952
Amortization	1,417	1,607	194	44	3,262
At December 31, 2022	$ 11,614	$ 17,862	$ 3,142	$ 1,596	$ 34,214
Net book value:					
At December 31, 2021	$ 82,763	$ 73,475	$ 8,950	$ 187	$ 165,375
At December 31, 2022	$ 88,126	$ 71,868	$ 8,756	$ 143	$ 168,893

17. DEFERRED REVENUE

	Customer Contributions	IPP Contracts	Decommissioning Fund	Total
At December 31, 2020	$ 17,345	$ -	$ 2,799	$ 20,144
Additions	717	1,767	13	2,497
Revenue recognized in Sales of Power and Other Revenue	(1,625)	(1,373)	-	(2,998)
At December 31, 2021	$ 16,437	$ 394	$ 2,812	$ 19,643
Additions	426	3,083	63	3,572
Revenue recognized in Sales of Power and Other Revenue	(1,315)	(3,201)	-	(4,516)
At December 31, 2022	$ 15,548	$ 276	$ 2,875	$ 18,699

The decommissioning fund represents monies paid in advance by an industrial customer to decommission the spur line that connects its operation to the Utility's grid. Under a power purchase agreement, the customer has the financial responsibility for decommissioning activities 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"). This amount will be recognized to revenue when uncertainty associated with its recognition is satisfied.

Yukon Energy Corporation

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17. DEFERRED REVENUE - continued

In order to provide more relevant information about the Utility's contracts, the Utility has presented customer contributions and IPP contracts information on a disaggregated basis in this note. The following table summarizes the impacts on the comparative figures of Deferred Revenue.

	2021 Previously Reported	Change	2021 Reclassified
Customer contracts	$ 16,831	$ (394)	$ 16,437
IPP contracts	-	394	394
Decommissioning fund	2,812	-	2,812
	$ 19,643	$ -	$ 19,643

In addition, the Utility identified that the amount previously reported as customer contributions additions for 2021 had reflected IPP contract additions of $1,767,000 and revenue recognized of $1,373,000 on a net basis of $394,000. The disclosure has been revised to report these on separate lines.

These changes did not impact the financial statements or any other note disclosures.

The following table includes revenue expected to be recognized in the future related to performance obligations that are unsatisfied as at December 31, 2022:

	Less than 1 year	Between 1 and 5 years	More than 5 years	Total
Customer contracts	$ 1,326	$ 5,280	$ 8,942	$ 15,548
IPP contracts	276	-	-	276
Decommissioning fund	-	-	2,875	2,875
	$ 1,602	$ 5,280	$ 11,817	$ 18,699

Yukon Energy Corporation

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18. SALES OF POWER

	2022	2021
Wholesale	$ 46,993	$ 46,502
Industrial	20,753	19,438
General service	8,193	8,051
Residential	4,079	4,175
Secondary sales	365	330
Sentinel and street lights	137	137
	$ 80,520	$ 78,633

19. OTHER REVENUE

The Utility recognized $3,201,000 (2021 - $1,373,000) in other revenue related to IPP contracts (Note 17).

During 2020, deformation was identified in WH1 and WH2 penstocks and major repairs were required. These repairs were completed during 2020 and 2021. The Utility recognized insurance proceeds revenue of $2,368,000 during 2021. There was no amount for 2022.

The Utility collected the outstanding 2021 insurance receivable during 2022 (Note 5).

20. OPERATIONS AND MAINTENANCE EXPENSES

	2022	2021
Fuel	$ 11,642	$ 8,935
Contractors	6,760	4,929
Wages and benefits	6,516	6,696
Regulatory account expenses (Note 10(c))	4,576	6,968
Rent	3,028	2,971
Materials and consumables	2,099	1,284
Travel	409	340
Communication	87	92
Loss on asset disposals	61	1,803
	$ 35,178	$ 34,018

Yukon Energy Corporation

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21. ADMINISTRATION EXPENSES

	2022	2021
Wages and benefits	$ 7,098	$ 6,470
Insurance and taxes	2,702	2,380
External labour	1,956	1,893
Materials, consumables and general	1,684	1,787
Licences and fees	1,083	922
Travel	224	86
Board fees	109	115
	$ 14,856	$ 13,653

22. RELATED PARTY TRANSACTIONS

The Utility is related in terms of common ownership to all YG departments, agencies and Territorial Corporations. Transactions are entered into in the normal course of operations with these entities. All sales of power transactions are recorded at the rates approved by the YUB.

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 with YDC for the year:

	2022	2021
Revenue		
Sales of service	$ 4	$ 4
Rate subsidy	924	280
Operating expenses		
Interest expense	$ 3,998	$ 4,005
Dividends	$ 11,500	$ -
Other payments/deductions		
Repayment of long-term debt	$ 4,860	$ 4,860

Yukon Energy Corporation

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22. RELATED PARTY TRANSACTIONS - continued

At the end of the year, the amounts receivable from and due to related parties are as follows:

	December 31 2022	December 31 2021
YDC		
Accounts receivable	$ 4,144	$ 925
Accounts payable	1,012	1,216
Construction financing	21,017	21,017
Dividends payable	11,500	-
Current portion of long-term debt	4,860	4,860
Long-term debt	115,901	120,761
YG		
Accounts receivable	$ 209	$ 331
Accounts payable	410	-

Included in Accounts receivable from YDC is an amount of $3,992,000 for capital projects funded by the federal government, which are administered through YG and YDC (2021 - $896,000).

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 ten senior management team positions and nine Board of Directors positions. Key management personnel compensation is as follows:

Year ended December 31	2022	2021
Short-term employee benefits	$ 1,823	$ 1,846
Post-employment benefits	145	209
	$ 1,968	$ 2,055

23. COMMITMENTS

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, 2022 as the product or service had not been provided. The total commitments at year end are $72,322,000 (2021 - $19,901,000).

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24. CONTINGENCIES

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 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.

25. 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. No significant environmental contamination was found. As at December 31, 2022 no significant provisions for environmental liabilities, for which a legal obligation exists to remediate, have been identified by the Utility. The Utility has its Environmental Management System to monitor and assess previous and potential existing environmental liabilities on an ongoing basis. The Utility does not have a provision for environmental liabilities as there is no significant present obligation to remediate.

26. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

At December 31, 2022, the Utility's financial instruments included accounts receivable, bank indebtedess, accounts payable and accrued liabilities, construction financing, long-term debt and interest rate swaps. The fair values of accounts receivable, bank indebtedness, accounts payable and accrued liabilities and construction financing approximate their carrying values due to the immediate or short-term maturity of these financial instruments.

Interest rate swaps are financial contracts that derive their value from changes in an underlying variable. 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.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2022

26. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

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.

The fair value of the interest rate swap agreements on December 31, 2022 was an asset of $4,908,000 (2021 - liability of $2,479,000). The increase in the fair value in 2022 of $7,387,000 (2021 – $2,571,000) is recognized on the Statement of Operations and Other Comprehensive Income as an unrealized gain. A 100 basis point increase or decrease in the interest rate assumption would have resulted in an increase/decrease in the interest rate swap agreements fair value of $6,371,000 (2021 - $5,020,000).

The Utility has access to a line of credit. As at January 1, 2021, the line of credit was $36.0 million. Effective April 22, 2021, the line of credit was increased temporarily to $43.0 million. Effective July 1, 2022, the line of credit was increased temporarily to $65.0 million. The temporary increase expires June 30, 2023. The account accrues interest on withdrawals at prime rate minus 0.75% (2021 - prime rate minus 0.75%) per annum. The interest rate risk is minimal.

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.

The following table illustrates the maximum credit exposure to the Utility if all counterparties defaulted:

	December 31 2022	December 31 2021
Accounts receivable	$ 20,404	$ 16,123
	$ 20,404	$ 16,123

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, 2022 is $4,957,000 (2021 - $1,517,000), of which $3,851,000 pertains to one customer. The Utility has established a payment plan with the customer. Subsequent to year end the customer has paid $2,692,000 resulting in $1,159,000 remaining outstanding. The Utility expects all amounts will be received in full, and therefore, has not recognized an allowance provision.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2022

26. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

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 of long-term debt which is predominantly due to the Parent. 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, 2022:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related asset	-	$4,908	-	$4,908
Long-term debt	-		$174,500	$174,500

The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2021:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related liability	-	$2,479	-	$2,479
Long-term debt	-	-	$179,300	$179,300

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2022

27. 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 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.

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, as well as the decommissioning fund (Note 17). Short-term debt related to assets under construction at the Statement of Financial Position date is excluded from the calculation of total debt, as the assets are similarly excluded from the determination of rate base. Total capitalization is calculated as total debt plus total shareholder's equity as shown on the Statement of Financial Position. The Utility maintains a balance in retained earnings as an indicator of the Utility's equity position.

The table below summarizes the Utility's total debt to total capitalization position:

	December 31 2022	2021
Long-term debt due within one year	$ 6,900	$ 6,537
Long-term debt	178,051	167,037
Total debt	184,951	173,574
Add decommissioning fund (Note 17)	2,875	2,812
Total debt to include in the calculation	$ 187,826	$ 176,386
Share capital	$ 39,000	$ 39,000
Contributed surplus	15,968	15,968
Retained earnings	94,796	82,684
Total shareholder's equity	149,764	137,652
Total capitalization	$ 337,590	$ 314,038
Total debt to total capitalization	56 %	56 %

There were no changes in the Utility's approach to capital management during the period. During the year, the Utility declared a dividend of $11,500,000 (2021 - $0). There is no set payment date.

TAB 10
ORDERS IN COUNCIL

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

O.I.C. 1995/090
PUBLIC UTILITIES ACT

DÉCRET 1995/090
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

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* »

"natural gas" includes liquefied natural gas; « *gaz naturel* »
("natural gas" added by O.I.C. 2018/220)

"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

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*"

« gaz naturel » S'entend notamment du gaz naturel liquéfié. "*natural gas*"
(« gaz naturel » ajoutée par Décret 2018/220)

« 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

Electrical Company Limited provision to recover a fair return on their equity used to finance their rate 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)

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 to the class of major industrial customers.

(Subsection 2.1(1) added by O.I.C. 2008/149)
(Subsection 2.1(1) replaced by O.I.C. 2012/68)
(Subsection 2.1(1) amended by O.I.C. 2018/220)

(2)

(Subsection 2.1(2) added by O.I.C. 2008/149)
(Subsection 2.1(2) replaced by O.I.C. 2012/68)
(Subsection 2.1(2) repealed by O.I.C. 2018/220)

(3)

(Subsection 2.1(3) added by O.I.C. 2012/68)
(Subsection 2.1(3) amended by O.I.C. 2014/23)
(Subsection 2.1(3) repealed by O.I.C. 2018/220)

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,

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) 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)

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 à toutes les catégories de clients industriels majeurs.

(Paragraphe 2.1(1) ajouté par Décret 2008/149)
(Paragraphe 2.1(1) modifié par Décret 2012/68)
(Paragraphe 2.1(1) modifié par Décret 2018/220)

(2)

(Paragraphe 2.1(2) ajouté par Décret 2008/149)
(Paragraphe 2.1(2) modifié par Décret 2012/68)
(Paragraphe 2.1(2) abrogé par Décret 2018/220)

(3)

(Paragraphe 2.1(3) ajouté par Décret 2012/68)
(Paragraphe 2.1(3) modifié par Décret 2014/23)
(Paragraphe 2.1(3) abrogé par Décret 2018/220)

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) 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-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.

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

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 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.

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 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.

Rates - major and isolated industrial customers

6.(1) The Board must ensure that the rates charged to major industrial 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.

(Subsection 6(1) amended by O.I.C. 2018/220)

(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.

(3) Despite subsection (1), the Board must ensure that the rates charged to major industrial customers conform to section 2.1.

(Subsection 6(3) added by O.I.C. 2007/94)
(Subsection 6(3) replaced by O.I.C. 2012/68)
(Subsection 6(3) amended by O.I.C. 2014/23)
(Subsection 6(3) replaced by O.I.C. 2018/220)

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

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.

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.

(3) Malgré le paragraphe (1), la Commission veille à ce que les tarifs facturés aux clients industriels majeurs soient conformes à l'article 2.1.

(Paragraphe 6(3) ajouté par Décret 2007/94)
(Paragraphe 6(3) remplacé par Décret 2012/68)
(Paragraphe 6(3) modifé par Décret 2014/23)
(Paragraphe 6(3) remplacé par Décret 2018/220)

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 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 and natural gas, without the requirement for specific application to and approval of the Board.

(Section 8 amended by O.I.C. 2018/220)

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 et le gaz naturel par ces deux sociétés, sans avoir à faire une demande particulière à la Commission pour obtenir son autorisation.

(Article 8 modifié par Décret 2018/220)

SCHEDULE A

("Schedule A, Industrial Primary Rate Schedule 39" added by O.I.C. 2007/94)
("Schedule A, Industrial Primary Rate Schedule 39" valid until Dec. 31, 2012 see Subsection 6(3))
("Schedule A, Industrial Primary Rate Schedule 39" valid until Dec. 31, 2013 see Subsection 6(3), amended by O.I.C. 2012/68)
("Schedule A, Industrial Primary Rate Schedule 39" valid until Dec. 31, 2018 see Subsection 6(3), amended by O.I.C. 2014/23)
(Schedule A repealed by O.I.C. 2018/220)

ANNEXE A

(« Annexe A, Clients industriels annexe tarifaire nº 39 » ajoutée par décret 2007/94)
(« Annexe A, Clients industriels annexe tarifaire nº 39 » valide jusqu'au 31 décembre 2012, voir paragraphe 6(3))
(« Annexe A, Clients industriels annexe tarifaire nº 39 » valide jusqu'au 31 décembre 2013, voir paragraphe 6(3), modifié par Décret 2012/68)
(« Annexe A, Clients industriels annexe tarifaire nº 39 » valide jusqu'au 31 décembre 2018, voir paragraphe 6(3), modifié par Décret 2014/23)
(Annexe A abrogée par Décret 2018/220)

PUBLIC UTILITIES ACT

Pursuant to the *Public Utilities Act*, the Commissioner in Executive Council orders

1 The attached *Direction to the Yukon Utilities Board (Independent Power Production)* is made.

Dated at Whitehorse, Yukon, January 25, 2019.

____
Commissioner of Yukon

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

La commissaire en conseil exécutif, conformément à la *Loi sur les entreprises de service public*, décrète :

1 Est établi l'*Instruction à l'intention de la régie des entreprises de service public (production indépendante d'énergie)* paraissant en annexe.

Fait à Whitehorse, au Yukon, le 25 janvier 2019.

____
Commissaire du Yukon

O.I.C. 2019/25
PUBLIC UTILITIES ACT

DIRECTION TO THE YUKON UTILITIES BOARD (INDEPENDENT POWER PRODUCTION)

Definitions

1 In this Direction

"ATCO Electric Yukon" means The Yukon Electrical Company Limited doing business as ATCO Electric Yukon; « *ATCO Electric Yukon* »

"CPI" means the All-Items Consumer Price Index for Canada published by Statistics Canada; « *IPC* »

"electrical grid" means the interconnected network of equipment and infrastructure, owned by Yukon Energy Corporation and ATCO Electric Yukon, for the generation, transmission and delivery of electricity in Yukon; « *réseau de distribution d'électricité* »

"electrical grid service area" means the area of Yukon to which electricity is delivered by means of the electrical grid; « *région desservie par le réseau de distribution d'électricité* »

"electrical utility" means Yukon Energy Corporation or ATCO Electric Yukon; « *service public d'électricité* »

"electricity purchase agreement" means an agreement between an electrical utility and the owner of an independent power production facility for the purchase, by the utility, of electricity generated by the facility; « *contrat d'achat d'électricité* »

"generating unit" means a device used to generate electricity; « *unité de production* »

"independent power production facility" means a facility in Yukon that

(a) comprises one or more generating units each of which generates electricity exclusively from a renewable energy source,

(b) has a nameplate capacity of at least 30 kW, and

(c) is a prescribed undertaking under the *Independent Power Production and Micro-Generation Regulation*;
« *installation indépendante de production d'énergie* »

DÉCRET 2019/25
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INSTRUCTION À L'INTENTION DE LA RÉGIE DES ENTREPRISES DE SERVICE PUBLIC (PRODUCTION INDÉPENDANTE D'ÉNERGIE)

Définitions

1 Les définitions suivantes s'appliquent à la présente instruction :

« ATCO Electric Yukon » La Yukon Electrical Company Limited faisant affaires sous le nom d'ATCO Electric Yukon. "*ATCO Electric Yukon*"

« capacité nominale » À l'égard d'une installation de production indépendante d'énergie, la puissance maximale de sortie nominale d'électricité de l'installation. "*nameplate capacity*"

« collectivité hors-réseau » Beaver Creek, Burwash Landing, Old Crow ou Watson Lake. "*off-grid community*"

« contrat d'achat d'électricité en réseau » Un contrat d'achat d'électricité à l'égard d'une installation de production indépendante d'énergie qui est située dans la région desservie par le réseau de distribution d'électricité. "*on-grid electricity purchase agreement*"

« contrat d'achat d'électricité hors-réseau » Un contrat d'achat d'électricité à l'égard d'une installation de production indépendante d'énergie qui est située dans une collectivité hors-réseau. "*off-grid electricity purchase agreement*"

« contrat d'achat d'électricité » Un contrat entre un service public d'électricité et le propriétaire d'une installation de production indépendante d'énergie pour l'achat par le service public d'électricité produite par cette installation. "*electricity purchase agreement*"

« installation de production indépendante d'énergie » Une installation au Yukon qui :

a) comprend une ou plusieurs unités de production dont chacune produit de l'électricité exclusivement à partir d'une source d'énergie renouvelable;

b) possède une capacité nominale d'au moins 30 kW;

c) est une entreprise visée par règlement en vertu “nameplate capacity”, of an independent power production facility, means the maximum rated output of electricity of the facility; « *capacité nominale* »

“off-grid community” means Beaver Creek, Burwash Landing, Old Crow or Watson Lake; « *collectivité hors-réseau* »

“off-grid electricity purchase agreement” means an electricity purchase agreement in respect of an independent power production facility that is located in an off-grid community; « *contrat d’achat d’électricité hors-réseau* »

“on-grid electricity purchase agreement” means an electricity purchase agreement in respect of an independent power production facility that is located in the electrical grid service area; « *contrat d’achat d’électricité en réseau* »

“renewable energy source” means

(a) moving water,

(b) wind,

(c) heat from the earth,

(d) sunlight, or

(e) biomass;
« *source d'énergie renouvelable* »

“thermal generation” means the generation of electricity from diesel or natural gas. « *production thermique* »

Costs recoverable by electrical utility

2(1) In setting rates that an electrical utility is permitted to charge, the board must allow the utility to recover the costs described in subsection (2) if the electricity purchase agreement in respect of which the costs are incurred provides for the matters set out in sections 3 to 6.

du Règlement portant sur la production indépendante d’énergie et la micro-production.
“*independent power production facility*”

« IPC » L’indice d’ensemble des prix à la consommation pour le Canada publié par Statistique Canada. “*CPI*”

« production thermique » La production d’électricité à partir de diesel ou de gaz naturel. “*thermal generation*”

« région desservie par le réseau de distribution d’électricité » La région du Yukon où l’électricité est livrée au moyen du réseau de distribution d’électricité. “*electrical grid service area*”

« réseau de distribution d’électricité » Le réseau interconnecté d'équipement et d'infrastructure, appartenant à la Société d'énergie du Yukon et à ATCO Electric Yukon, pour la production, la transmission et la livraison de l'électricité au Yukon. “*electrical grid*”

« service public d’électricité » La Société d'énergie du Yukon ou ATCO Electric Yukon. “*electrical utility*”

« source d'énergie renouvelable » S’entend des sources suivantes :

a) l’eau en mouvement;

b) le vent;

c) la chaleur de la terre;

d) la lumière du soleil;

e) la biomasse.
“*renewable energy source*”

« unité de production » Un appareil utilisé pour produire de l’électricité. “*generating unit*”

Coûts recouvrables par un service public d’électricité

2(1) Lorsque la régie fixe les taux qu'un service public d'électricité est autorisé à exiger, elle doit lui permettre de recouvrer les coûts visés au paragraphe (2) si le contrat d'achat d'électricité à l'égard duquel les coûts sont engagés prévoit les éléments énoncés aux articles 3 à 6.

(2) For the purposes of subsection (1), the costs are the following:

(a) the cost of purchasing electricity under an electricity purchase agreement;

(b) third party consultant costs, including legal fees, incurred by an electrical utility in relation to the development and implementation of the agreement;

(c) the cost of maintaining or replacing equipment or infrastructure necessary to purchase electricity under the agreement.

(2) Pour l'application du paragraphe (1), les coûts sont les suivants:

a) le coût d'achat de l'électricité en vertu d'un contrat d'achat d'électricité;

b) les coûts pour un consultant indépendant, y compris les frais juridiques, engagés par un service public d'électricité relativement à l'élaboration et à la mise en œuvre du contrat;

c) les coûts de l'entretien ou du remplacement de l'équipement ou de l'infrastructure nécessaires à l'achat d'électricité en vertu du contrat.

Price for electricity under electricity purchase agreement

3(1) The price paid by an electrical utility for a kWh of electricity under an off-grid electricity purchase agreement

(a) is to be based on the weighted average cost of fuel purchased by the utility for the purpose of producing electricity by means of thermal generation for the five years immediately preceding the date on which the agreement takes effect; and

(b) is to account for any reduction in the maintenance, capital or other costs arising from the displacement of thermal generation as a result of the electricity generated by the facility.

(2) The price paid by an electrical utility for a kWh of electricity under an on-grid electricity purchase agreement is to be based on the utility’s average blended fuel price per kWh for thermal generation most recently approved by the board before the date on which the agreement takes effect.

Prix de l'électricité en vertu du contrat d'achat d'électricité

3(1) Le prix payé par un service public d'électricité pour un kWh d'électricité en vertu d'un contrat d'achat d'électricité hors-réseau :

a) repose sur le coût moyen pondéré du combustible acheté par le service public aux fins de production d'électricité par production thermique pendant les cinq années précédant immédiatement la date à laquelle le contrat entre en vigueur;

b) tient compte de toute réduction des coûts d'entretien, d'immobilisations ou autres coûts découlant du déplacement de la production thermique par suite de l'électricité produite par l'installation.

(2) Le prix payé par un service public d'électricité pour un kWh d'électricité en vertu d'un contrat d'achat d'électricité en réseau repose sur le prix moyen du combustible mixte par kWh de la production thermique approuvée en dernier lieu par la régie avant la date à laquelle le contrat entre en vigueur.

Annual CPI adjustment

4(1) The price paid by an electrical utility for a kWh of electricity under an electricity purchase agreement is to be adjusted annually in accordance with subsection (2) or (3).

(2) In the case of an off-grid electricity purchase agreement, the price for a kWh of electricity for a particular year is to be determined by increasing the price paid in the year immediately preceding the particular year in accordance with the percentage increase, if any, in the CPI.

Rajustement annuel en fonction de l'IPC

4(1) Le prix payé par un service public d'électricité pour un kWh d'électricité en vertu d'un contrat d'achat d'électricité est rajusté annuellement conformément au paragraphe (2) ou (3).

(2) Pour un contrat d'achat d'électricité hors-réseau, le prix d'un kWh d'électricité pour une année donnée est calculé en augmentant le prix payé au cours de l'année précédant immédiatement l'année donnée par l'augmentation en pourcentage, le cas échéant, de l'IPC.

(3) In the case of an on-grid electricity purchase agreement, the price for a kWh of electricity for a particular year is to be determined by increasing the price paid in the year immediately preceding the particular year in accordance with 50% of the percentage increase, if any, in the CPI.

(3) Pour un contrat d'achat d'électricité en réseau, le prix d'un kWh d'électricité pour une année donnée est calculé en augmentant le prix payé au cours de l'année précédant immédiatement l'année donnée par 50 % de l'augmentation en pourcentage, le cas échéant, de l'IPC.

Compensation

5(1) An electricity purchase agreement is to provide for reasonable compensation to be paid by the electrical utility to the owner of the independent power production facility in the event that the facility is unable to deliver electricity to the utility as a result of damage to, or a failure of, infrastructure or equipment for which the utility is responsible.

(2) An electricity purchase agreement need not provide for reasonable compensation to be paid by the utility to the owner of the facility in the event that the facility is unable to deliver electricity to the utility as a result of a planned outage.

Indemnisation

5(1) Un contrat d'achat d'électricité prévoit le versement d'une indemnité raisonnable par le service public d'électricité au propriétaire de l'installation de production indépendante d'énergie lorsque l'installation est incapable de lui fournir de l'électricité en raison de dommages ou d'une défaillance des infrastructures ou de l'équipement dont le service public est responsable.

(2) Un contrat d'achat d'électricité n'est pas tenu de prévoir une indemnisation raisonnable que le service public doit verser au propriétaire de l'installation dans l'éventualité où l'installation est incapable de lui fournir de l'électricité en raison d'un arrêt planifié.

Term of electricity purchase agreement

6 The term of an electricity purchase agreement is to be at least 20 years.

Durée du contrat d'achat d'électricité

6 La durée d'un contrat d'achat d'électricité est d'au moins 20 ans.

PUBLIC UTILITIES ACT

Pursuant to the *Public Utilities Act*, the Commissioner in Executive Council orders

1 The attached *Independent Power Production and Micro-Generation Regulation* is made.

Dated at Whitehorse, Yukon, January 25, 2019.

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Commissioner of Yukon

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

La commissaire en conseil exécutif, conformément à la *Loi sur les entreprises de service public*, décrète :

1 Est établi le R*èglement portant sur la production indépendante d'énergie et la micro-production* paraissant en annexe.

Fait à Whitehorse, au Yukon, le 25 janvier 2019.

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Commissaire du Yukon

INDEPENDENT POWER PRODUCTION AND MICRO-GENERATION REGULATION

Interpretation

1(1) In this Regulation

"director" means the director of the Energy Branch in the Department of Energy, Mines and Resources; « *directeur* »

"electrical system", of a public utility, means equipment or facilities in Yukon

(a) owned or operated by the public utility, and

(b) used by the public utility for the production, generation, storage, transmission, distribution, sale, delivery or furnishing of electricity; « *système électrique* »

"facility" means all of the generating units and related electrical equipment that are connected to the same meter; « *installation* »

"generating unit" means a device used to generate electricity; « *unité de production* »

"independent power production facility" means a facility in Yukon that

(a) comprises one or more generating units each of which generates electricity exclusively from a renewable energy source, and

(b) has a nameplate capacity of at least 30 kW; « *installation indépendante de production d'énergie* »

"micro-generation facility" means a facility in Yukon

(a) that comprises one or more generating units each of which generates electricity exclusively from a renewable energy source,

(b) whose nameplate capacity does not exceed the lesser of

(i) 50 kW, and

(ii) the maximum capacity that can be accommodated by the electrical system of a

RÈGLEMENT PORTANT SUR LA PRODUCTION INDÉPENDANTE D'ÉNERGIE ET LA MICRO-PRODUCTION

Interprétation

1(1) Les définitions suivantes s'appliquent au présent règlement :

« capacité nominale » À l'égard d'une installation, la puissance maximale de sortie nominale d'électricité de l'installation. "*nameplate capacity*"

« directeur » Le directeur de la Direction générale de l'énergie, ministère de l'Énergie, des Mines et des Ressources. "*director*"

« installation » Toutes les unités de production ou de matériel électrique connexe reliés au même compteur. "*facility*"

« installation de micro-production » Une installation au Yukon :

a) qui comprend une ou plusieurs unités de production dont chacune produit de l'électricité exclusivement à partir d'une source d'énergie renouvelable;

b) dont la capacité nominale ne dépasse pas la moins élevée des capacités suivantes :

(i) 50 kW,

(ii) la capacité maximale que peut atteindre le système électrique d'une entreprise de service public à laquelle l'installation est reliée;

c) qui n'est pas en mesure de produire annuellement plus de deux fois la consommation d'énergie annuelle moyenne estimée de la charge avec laquelle l'installation partage un compteur. "*micro-generation facility*"

« installation indépendante de production d'énergie » Une installation au Yukon qui :

a) comprend une ou plusieurs unités de production dont chacune produit de l'électricité exclusivement à partir d'une source d'énergie renouvelable;

public utility to which the facility is connected, and

(c) that is not capable of generating annually more than two times the estimated average annual energy consumption of the load with which the facility shares a meter; « *installation de micro-production* »

"nameplate capacity", of a facility, means the maximum rated output of electricity of the facility; « *capacité nominale* »

"renewable energy source" means

(a) moving water,

(b) wind,

(c) heat from the earth,

(d) sunlight, or

(e) biomass. « *source d'énergie renouvelable* »

(2) A person is affiliated with a public utility if the person and the public utility are "affiliated persons" or "persons affiliated with each other" within the meaning of the *Income Tax Act* (Canada).

Excluded undertaking — independent power production facility

2(1) For the purposes of the definition "excluded undertaking" in subsection 1(1) of the Act, an independent power production facility is a prescribed undertaking if

(a) the facility is not owned, in whole or in part, by a public utility or a person affiliated with a public utility; and

(b) the only electrical system, other than that of the person who owns the facility, to which the facility is connected is that of a public utility.

b) possède une puissance nominale d'au moins 30 kW. "*independent power production facility*"

« source d'énergie renouvelable » S'entend des sources suivantes :

a) l'eau en mouvement;

b) le vent;

c) la chaleur de la terre;

d) la lumière du soleil;

e) la biomasse. "*renewable energy source*"

« système électrique » À l'égard d'une entreprise de service public, les équipements ou les installations au Yukon :

a) dont elle est le propriétaire ou l'exploitant;

b) qu'elle utilise pour produire, stocker, transmettre, distribuer, vendre, livrer ou fournir de l'électricité. "*electrical system*"

« unité de production » Un appareil utilisé pour produire de l'électricité. "*generating unit*"

(2) Une personne est affiliée à une entreprise de service public si la personne et l'entreprise sont des « personnes affiliées » ou « des personnes affiliées les unes aux autres » au sens de la *Loi de l'impôt sur le revenu* (Canada).

Entreprise exclue — installation de production indépendante d'énergie

2(1) Pour l'application de la définition « entreprise exclue » au paragraphe 1(1) de la loi, une installation indépendante de production d'énergie est une entreprise visée par règlement si, à la fois :

a) l'installation n'appartient pas, en tout ou en partie, à une entreprise de service public ou à une personne affiliée à une telle entreprise;

b) le seul système électrique, autre que celui du propriétaire de l'installation, auquel l'installation est reliée, est celui d'une entreprise de service public.

(2) A public utility and the owner of an independent power production facility who intends to supply electricity generated by the facility, by means of one or more generating units, to the electrical system of the public utility may enter into an agreement for that purpose, on the terms agreed to by the parties.

Excluded undertaking — micro-generation facility

3 For the purposes of the definition "excluded undertaking" in subsection 1(1) of the Act, a micro-generation facility is a prescribed undertaking if

(a) the facility is not owned, in whole or in part, by a public utility or a person affiliated with a public utility;

(b) a portion of the electricity generated by the facility, by means of one or more generating units, is consumed by the person who owns the facility, their employees or their tenants; and

(c) the only electrical system, other than that of the person who owns the facility, to which the facility is connected is that of a public utility.

Connection of micro-generation facility to electrical system

4(1) The owner of a micro-generation facility must not supply electricity generated by the facility, by means of one or more generating units, to the electrical system of a public utility unless the owner has received approval from the director to do so, in accordance with this section.

(2) The owner of a micro-generation facility who intends to supply electricity generated by the facility, by means of one or more generating units, to the electrical system of a public utility must submit an application to the director in the form, if any, required by the director, that contains the following information:

(a) the name and contact information of the owner;

(b) the address of the facility;

(c) the nameplate capacity of the facility;

(2) Une entreprise de service public et le propriétaire d'une installation indépendante de production d'énergie qui a l'intention de fournir de l'électricité produite par l'installation, au moyen d'une ou de plusieurs unités de production, au système électrique de l'entreprise, peuvent conclure une entente à cette fin, selon les modalités convenues par les parties.

Entreprise exclue — installation de micro-production

3 Pour l'application de la définition « entreprise exclue » au paragraphe 1(1) de la loi, une installation de micro-production est une entreprise visée par règlement si, à la fois :

a) l'installation n'appartient pas, en tout ou en partie, à une entreprise de service public ou à une personne affiliée à une telle entreprise;

b) une partie de l'électricité produite par l'installation, au moyen d'une ou de plusieurs unités de production, est consommée par la personne qui en est propriétaire, ses employés ou ses locataires;

c) le seul système électrique, autre que celui du propriétaire de l'installation, auquel l'installation est reliée est celui d'une entreprise de service public.

Installation de micro-production reliée au système électrique

4(1) Le propriétaire d'une installation de micro-production ne doit pas fournir de l'électricité produite par l'installation, au moyen d'une ou de plusieurs unités de production, au système électrique d'une entreprise de service public sans avoir obtenu l'autorisation du directeur à cet effet, conformément au présent article.

(2) Le propriétaire d'une installation de micro-production qui a l'intention de fournir de l'électricité produite par l'installation, au moyen d'une ou de plusieurs unités de production, au système électrique d'une entreprise de service public doit présenter au directeur une demande en la forme exigée par ce dernier, le cas échéant, et qui contient les renseignements suivants :

a) le nom et les coordonnées du propriétaire;

b) l'adresse de l'installation;

c) la capacité nominale de l'installation;

(d) the renewable energy source from which the facility generates electricity;

(e) the manufacturer of each generating unit that is a part of the facility;

(f) the information required by the director for the purposes of determining the estimated average annual energy consumption of the load with which a facility shares a meter, which may include records showing the actual energy consumption of the load;

(g) any other information required by the director.

(3) On receipt of an application under subsection (2), the director must provide written notice of the application to the public utility to whose electrical system the facility is to be connected.

(4) A public utility that receives notice under subsection (3) must, within 60 days after receiving the notice, respond to the director in writing as to whether the nameplate capacity of the facility exceeds the maximum capacity that can be accommodated by the electrical system to which the facility is to be connected.

(5) After receiving an application under subsection (2) and a response from the public utility under subsection (4) in relation to the application, the director must determine whether the facility to which the application relates qualifies as a micro-generation facility.

(6) If the director determines that a facility to which an application under subsection (2) relates does not qualify as a micro-generation facility, the director must

(a) refuse the application; and

(b) provide written notice to the owner of the facility that the application is refused, including reasons for the refusal.

(7) If the director determines that a facility to which an application under subsection (2) relates qualifies as a micro-generation facility, the director must

(a) approve the application; and

d) la source d'énergie renouvelable à partir de laquelle l'installation produit de l'électricité;

e) le fabricant de chaque unité de production faisant partie de l'installation;

f) les renseignements dont le directeur a besoin pour déterminer la consommation d'énergie annuelle moyenne estimée de la charge avec laquelle une installation partage un compteur, ce qui peut comprendre des registres indiquant la consommation d'énergie réelle de la charge;

g) toute autre information requise par le directeur.

(3) Sur réception d'une demande visée au paragraphe (2), le directeur doit en aviser par écrit l'entreprise de service public dont le système électrique sera relié à l'installation.

(4) L'entreprise de service public qui reçoit l'avis prévu au paragraphe (3) doit, dans les 60 jours suivant la réception de l'avis, indiquer par réponse écrite au directeur si la capacité nominale de l'installation dépasse la capacité maximale que peut atteindre le système électrique auquel l'installation doit être reliée.

(5) Après avoir reçu la demande visée au paragraphe (2) et la réponse de l'entreprise de service public visée au paragraphe (4), le directeur doit déterminer si l'installation visée par la demande est admissible à titre d'installation de micro-production.

(6) Si le directeur détermine qu'une installation à laquelle s'applique une demande visée au paragraphe (2) n'est pas admissible à titre d'installation de micro-production, il doit :

a) refuser la demande;

b) aviser par écrit le propriétaire de l'installation que la demande est refusée, en indiquant les motifs du refus.

(7) Si le directeur détermine qu'une installation à laquelle s'applique une demande visée au paragraphe (2) est admissible à titre d'installation de micro-production, il doit

a) approuver la demande;

(b) provide written notice to the owner of the facility that the application is approved.

Connection of micro-generation facility to electrical system

5(1) Subject to subsection (2), the owner of a micro-generation facility whose application has been approved under section 4 may connect the facility to the electrical system of a public utility but only on the terms agreed to by the public utility and the owner of the facility.

(2) The owner of a micro-generation facility is responsible for the following costs:

(a) the costs of connecting the facility to the electrical system of a public utility, including the costs of making any necessary modifications or upgrades to the electrical system for the purposes of connecting the facility to the electrical system;

(b) the costs of operating the facility.

Change to nameplate capacity of micro-generation facility

6(1) The owner of a micro-generation facility that is connected to the electrical system of a public utility must not increase the nameplate capacity of the facility unless the increase has been approved by the director in accordance with this section.

(2) The owner of a micro-generation facility that is connected to the electrical system of a public utility who intends to increase the nameplate capacity of the facility must submit an application to the director, in the form, if any, required by the director and that contains the information required by the director.

(3) On receipt of an application under subsection (2), the director must provide written notice of the application to the public utility to whose electrical system the facility is connected.

(4) A public utility that receives notice under subsection (3) must, within 60 days after receiving the notice, respond to the director in writing as to whether the proposed increase to the nameplate capacity of the facility exceeds the maximum capacity that can be accommodated by the electrical system to which the facility is connected.

b) aviser par écrit le propriétaire de l'installation que la demande est approuvée.

Installation de micro-production reliée au système électrique

5(1) Sous réserve du paragraphe (2), le propriétaire d'une installation de micro-production dont la demande a été approuvée en vertu de l'article 4 peut relier l'installation au système électrique d'une entreprise de service public, mais seulement aux conditions convenues entre l'entreprise et le propriétaire de l'installation.

(2) Le propriétaire d'une installation de micro-production est responsable des coûts suivants :

a) les coûts pour relier l'installation au système électrique d'une entreprise de service public, y compris les coûts des modifications ou des améliorations nécessaires au système électrique pour relier l'installation au système électrique;

b) les coûts d'exploitation de l'installation.

Changement de la capacité nominale de l'installation de micro-production

6(1) Le propriétaire d'une installation de micro-production reliée au système électrique d'une entreprise de service public ne peut augmenter la capacité nominale de l'installation que si le directeur a approuvé l'augmentation conformément au présent article.

(2) Le propriétaire d'une installation de micro-production reliée au système électrique d'une entreprise de service public et qui a l'intention d'augmenter la capacité nominale de l'installation doit présenter une demande au directeur, en la forme exigée par ce dernier, le cas échéant, comprenant les renseignements que le directeur exige.

(3) Sur réception de la demande visée au paragraphe (2), le directeur doit en aviser par écrit l'entreprise de service public dont le système électrique est relié à l'installation.

(4) Une entreprise de service public qui reçoit l'avis prévu au paragraphe (3) doit, dans les 60 jours suivant la réception de l'avis, indiquer par réponse écrite au directeur si l'augmentation proposée de la capacité nominale de l'installation dépasse la capacité maximale que peut atteindre le système électrique auquel l'installation est reliée.

(5) After receiving an application under subsection (2) and a response from the public utility under subsection (4) in relation to the application, the director must determine whether the facility to which the application relates qualifies as a micro-generation facility despite the increase to the nameplate capacity of the facility proposed in the application.

(6) If, as a result of an increase to the nameplate capacity of a facility proposed in an application under subsection (2), the facility would no longer qualify as a micro-generation facility, the director must

(a) refuse the application; and

(b) provide written notice to the owner of the facility that the application is refused, including reasons for the refusal.

(7) If, despite an increase to the nameplate capacity of a facility proposed in an application under subsection (2), the facility would continue to qualify as a micro-generation facility, the director must

(a) approve the application; and

(b) provide written notice to the owner of the facility that the application is approved.

(5) Après avoir reçu la demande visée au paragraphe (2) et la réponse de l'entreprise de service public en vertu du paragraphe (4), le directeur doit déterminer si l'installation visée par la demande est admissible à titre d'installation de micro-production malgré l'augmentation de la capacité nominale de l'installation proposée dans la demande.

(6) Si, par suite de l'augmentation de la capacité nominale d'une installation proposée dans une demande présentée en vertu du paragraphe (2), l'installation ne serait plus admissible à titre d'installation de micro-production, le directeur doit :

a) refuser la demande;

b) aviser par écrit le propriétaire de l'installation que la demande est refusée, en indiquant les motifs du refus.

(7) Si, malgré l'augmentation de la capacité nominale d'une installation proposée dans une demande présentée en vertu du paragraphe (2), l'installation continuerait d'être admissible à titre d'installation de micro-production, le directeur doit

a) approuver la demande;

b) aviser par écrit le propriétaire de l'installation que la demande est approuvée.

YUKON

CANADA

ORDER-IN-COUNCIL 2021/ 16

PUBLIC UTILITIES ACT

Pursuant to the *Public Utilities Act*, the Commissioner in Executive Council orders

1 The attached *2021 Direction to amend the Rate Policy Directive (1995)* is issued.

Dated at Whitehorse, Yukon,
February 11, 2021.

YUKON

CANADA

DÉCRET 2021/16

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

La commissaire en conseil exécutif, conformément à la *Loi sur les entreprises de service public*, décrète :

1 Est donnée l'*Instruction de 2021 modifiant les Instructions sur la politique tarifaire (1995)* paraissant en annexe.

Fait à Whitehorse, au Yukon,
le 11 février 2021.

Commissioner of Yukon/Commissaire du Yukon

2020-0000216

2021-16

PUBLIC UTILITIES ACT

2021 DIRECTION TO AMEND THE RATE POLICY DIRECTIVE (1995)

1 This Direction amends the *Rate Policy Directive (1995)*.

Section 1 amended

2 In section 1, the following definition is added in alphabetical order:

"renewable generation" means generation of electricity from renewable sources, including hydro, wind, solar, geothermal and biomass sources; *« production d'énergie renouvelable »*

Sections 9, 10 and 11 added

3 The following sections are added immediately after section 8:

Fuel costs and low water deferral account

9(1) In this section

"long-term average annual renewable source availability" means the annual amount of renewable generation that would be available to contribute to meeting forecast or actual customer requirements, based on average annual renewable source availability over the life of a renewable generation facility, as determined using available historical water records respecting long-term average annual hydro generation and available information respecting other

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INSTRUCTION DE 2021 MODIFIANT LES INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

1 La présente instruction modifie les *Instructions sur la politique tarifaire (1995)*.

Modification de l'article 1

2 À l'article 1, la définition qui suit est insérée selon l'ordre alphabétique :

« production d'énergie renouvelable » Production d'électricité à partir de sources d'énergie renouvelable, y compris l'énergie hydroélectrique, l'énergie éolienne, l'énergie solaire, l'énergie géothermique et la biomasse. *"renewable generation"*

Ajout des articles 9, 10 et 11

3 Les articles qui suivent sont ajoutés après l'article 8 :

Coûts du combustible et compte de report de bas niveau d'eau

9(1) La définition qui suit s'applique au présent article.

« disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable » La quantité annuelle de la production d'énergie renouvelable qui serait disponible pour aider à répondre aux besoins prévus ou réels de clients, fondée sur la disponibilité annuelle moyenne de sources d'énergie renouvelable au cours de la durée utile d'une installation de production d'énergie renouvelable, déterminée à l'aide des documents historiques de niveau d'eau disponibles renewable generation. *« disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable »*

concernant la production hydroélectrique annuelle moyenne à long terme et les renseignements disponibles concernant d'autre production d'énergie renouvelable. *"long-term average annual renewable source availability"*

(2) The Board must include in the rates of Yukon Energy Corporation provision to recover forecast fuel costs for the amount of thermal generation needed to meet forecast customer requirements.

(2) La Régie doit prévoir dans les tarifs de la Société d'énergie du Yukon les mesures pour recouvrer les coûts du combustible prévus pour la quantité de production d'énergie thermique nécessaire pour répondre aux besoins prévus de clients.

(3) For the purpose of subsection (2), the Board must determine the forecast fuel costs for a financial year of Yukon Energy Corporation by

(3) Pour l'application du paragraphe (2), la Régie détermine les coûts du combustible prévus pour un exercice de la Société d'énergie du Yukon de la façon suivante :

(a) forecasting the amount of renewable generation available to contribute to meeting forecast customer requirements, based on long-term average annual renewable source availability;

a) en prévoyant la quantité de production d'énergie renouvelable disponible pour aider à répondre aux besoins prévus des clients, fondée sur la disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable;

(b) forecasting the amount of thermal generation needed to meet any shortfall between the forecast renewable generation under paragraph (a) and forecast customer requirements; and

b) en prévoyant la quantité de production d'énergie thermique nécessaire pour combler tout manque entre la production d'énergie renouvelable prévue au titre de l'alinéa a) et les besoins prévus des clients;

(c) determining the costs of fuel for forecast thermal generation under paragraph (b) based on forecast prices for diesel fuel and natural gas as approved by the Board.

c) en déterminant les coûts du combustible pour la production d'énergie thermique au titre de l'alinéa b) en fonction des prix prévus du mazout et du gaz naturel approuvés par la Régie.

(4) After each financial year of Yukon Energy Corporation, the Board must review and approve the difference between the following:

(4) Après chaque exercice de la Société d'énergie du Yukon, la Régie examine et approuve la différence entre les éléments suivants :

(a) the fuel costs for the amount of thermal generation needed to meet actual customer requirements for the financial year as a result of any shortfall between

a) les coûts du combustible pour la quantité de production d'énergie thermique nécessaire pour répondre aux besoins réels de clients pour l'exercice actual renewable generation and actual customer requirements;

(b) the fuel costs for the amount of thermal generation that would have been needed to meet actual customer requirements for the financial year if renewable generation had been consistent with long-term average annual renewable source availability.

(5) The fuel costs referred to in subsection (4) are to be determined based on the forecast prices referred to in paragraph (3)(c) that are applicable to that financial year.

(6) The Board must require Yukon Energy Corporation to operate a low water deferral account for the purpose of minimizing the effect on rates for retail customers and major industrial customers that would otherwise be caused by the variation in actual renewable source availability, including the variation caused by drought conditions.

(7) For each financial year of Yukon Energy Corporation, the Board must require Yukon Energy Corporation

(a) to credit the low water deferral account by the amount of the difference in fuel costs for thermal generation approved under subsection (4), if actual renewable source availability is greater than long-term average annual renewable source availability; or

(b) to charge the low water deferral account by the amount of the difference in fuel costs for thermal generation approved under subsection (4), if actual renewable

résultant de tout manque entre la production d'énergie renouvelable réelle et les besoins réels de clients;

b) les coûts du combustible pour la quantité de production thermique qui aurait été requise pour répondre aux besoins réels des clients pour l'exercice si la production d'énergie renouvelable avait été conforme à la disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable.

(5) Les coûts du combustible mentionnés au paragraphe (4) sont déterminés en fonction des prix prévus mentionnés à l'alinéa (3)c) qui sont applicables à l'exercice en cause.

(6) La Régie exige de la Société d'énergie du Yukon qu'elle gère un compte de report de bas niveau d'eau dans le but d'atténuer les effets sur les tarifs pour les clients au détail et les clients industriels majeurs qui seraient autrement causés par la variation de disponibilité réelle de sources d'énergie renouvelable, y compris la variation causée par des conditions de sécheresse.

(7) Pour chaque exercice de la Société d'énergie du Yukon, la Régie exige de la Société d'énergie du Yukon, selon le cas :

a) qu'elle porte au crédit du compte de report de bas niveau d'eau les sommes correspondant à la différence des coûts du combustible pour la production énergie thermique approuvés en application du paragraphe (4), si la disponibilité réelle de sources d'énergie renouvelable est supérieure à la disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable;

b) qu'elle débite le compte de report de bas niveau d'eau des sommes correspondant à la différence des coûts du combustible pour la production d'énergie source availability is less than long-term average annual renewable source availability.

(8) The Board must set the maximum balance and minimum balance for the low water deferral account at amounts sufficient to achieve the purpose described in subsection (6).

(9) The Board must require that Yukon Energy Corporation apply to the Board for approval of an adjustment of rates for customers to enable

(a) a drawdown of the low water deferral account if the balance of the low water deferral account is greater than the maximum balance set under subsection (8); or

(b) a replenishment of the low water deferral account if the balance of the low water deferral account is less than the minimum balance set under subsection (8).

(10) This section applies only in respect of an application, report or other filing that is made in the first instance to the Board on or after November 1, 2020 and for which no order is issued under section 27 of the Act before this section comes into force.

Recovery of costs for demand-side management program

10(1) In this section

"demand-side management program" means a measure, action or program intended to promote customer

thermique approuvés en application du paragraphe (4), si la disponibilité réelle de sources d'énergie renouvelable est inférieure à la disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable.

(8) La Régie fixe les soldes maximal et minimal du compte de report de bas niveau d'eau aux montants suffisants pour atteindre le but mentionné au paragraphe (6).

(9) La Régie exige que la Société d'énergie du Yukon lui présente une demande d'approbation d'un ajustement tarifaire pour les clients afin de permettre, selon le cas :

a) le prélèvement du compte de report de bas niveau d'eau si le solde est supérieur au solde maximal fixé en application du paragraphe (8);

b) la reconstitution de ce compte si le solde est inférieur au solde minimal fixé en application du paragraphe (8).

(10) Le présent article s'applique seulement à l'égard d'une demande, d'un rapport ou d'un autre dépôt fait à la Régie en tout premier lieu à compter du 1er novembre 2020 et pour lesquels aucune ordonnance n'a été rendue en vertu de l'article 27 de la Loi avant l'entrée en vigueur du présent article.

Recouvrement des coûts d'un programme de gestion axée sur la demande

10(1) La définition qui suit s'applique au présent article.

« programme de gestion axée sur la demande » Mesure, action ou programme destiné à promouvoir une consommation use of electricity that optimizes economy or efficiency of electricity generation or transmission by a public utility, including through the promotion of customer use of electricity that

(a) is more efficient, or

(b) better aligns electricity supply and demand. *« programme de gestion axée sur la demande »*

(2) The Board must include in the rates of a public utility for retail customers and major industrial customers provision to recover costs the public utility reasonably incurs to provide or participate in a demand-side management program.

(3) In determining whether costs are reasonably incurred by a public utility to provide or participate in a demand-side management program, the Board must consider the extent of any duplication between the program for which costs are incurred and a demand-side management program provided by the Government of Yukon or in which the Government of Yukon is a participant.

(4) This section applies only in respect of an application, report or other filing that is made in the first instance to the Board on or after November 1, 2020 and for which no order is issued under section 27 of the Act before this section comes into force.

Recovery of costs for renewable generation project planning or development

11(1) The Board must include in the rates of a public utility for retail customers and major industrial customers provision to

d'électricité par les clients qui optimise l'économie ou l'efficacité de la production ou la transmission d'électricité par une entreprise de service public, notamment grâce à la promotion d'une consommation d'électricité par les clients qui, selon le cas :

a) est plus efficace;

b) harmonise mieux l'approvisionnement et la demande en électricité. *"demand-side management program"*

(2) La Régie doit prévoir dans les tarifs d'une entreprise de service public pour les clients au détail et les clients industriels majeurs les mesures pour recouvrer les frais que l'entreprise de service public engage raisonnablement pour fournir un programme de gestion axée sur la demande ou y participer.

(3) Pour établir si les frais sont raisonnablement engagés par une entreprise de service public pour fournir un programme de gestion axée sur la demande ou y participer, la Régie tient compte de l'étendue de tout chevauchement entre le programme pour lequel les frais ont été engagés et un programme de gestion axée sur la demande que fournit le gouvernement du Yukon ou auquel il participe.

(4) Le présent article s'applique seulement à l'égard d'une demande, d'un rapport ou d'un autre dépôt fait à la Régie en tout premier lieu à compter du 1er novembre 2020 et pour lesquels aucune ordonnance n'a été rendue en vertu de l'article 27 de la Loi avant l'entrée en vigueur du présent article.

Recouvrement des coûts de planification ou de développement de projets de production d'énergie renouvelable

11(1) La Régie doit prévoir dans les tarifs d'une entreprise de service public pour les clients au détail et les clients industriels recover costs the public utility reasonably incurs to plan or develop renewable generation projects.

majeurs les mesures pour recouvrer les frais que l'entreprise de service public engage raisonnablement pour planifier ou développer des projets de production d'énergie renouvelable.

(2) This section applies only in respect of an application, report or other filing that is made in the first instance to the Board on or after November 1, 2020 and for which no order is issued under section 27 of the Act before this section comes into force.

(2) Le présent article s'applique seulement à l'égard d'une demande, d'un rapport ou d'un autre dépôt fait à la Régie en tout premier lieu à compter du 1er novembre 2020 et pour lesquels aucune ordonnance n'a été rendue en vertu de l'article 27 de la Loi avant l'entrée en vigueur du présent article.

Expression replaced

4 In the French version, the expression "Commission" **is replaced, wherever it occurs, with the expression** "Régie".

Remplacement d'une expression

4 Dans la version française, l'expression « Commission » **est remplacée, à chaque occurrence, par l'expression** « Régie ».