YUKON ENERGY CORPORATION

2025-27 GENERAL RATE APPLICATION

MAY 2025

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TO THE YUKON UTILITIES BOARD

INTRODUCTION TO APPLICATION

Yukon Energy Corporation's (Yukon Energy or YEC) 2025-27 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 adapt to Yukon's changing demand for 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 2025, 2026 and 2027 rate adjustments for retail customers and industrial customers apply equally, as percentages through increases in non-industrial and industrial Rider J.

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 and approval of the timing for implementation of YEC's interim rate increases to reduce the impact of final rates and avoid a large true-up. Through this

[1] Ride J is applicable to all firm retail customer class base rates and to firm major industrial customer class base rates. Rider J is not applicable to riders, therefore, the requested increase in Rider J is higher than the required rate increase.

approach, the impact of YEC's 2025, 2026 and 2027 rate increases on customer bills will be smooth, and greater bill stability and predictability will be provided to Yukoners. The proposed approach includes the following dates for rate adjustments:

- Interim rate change effective July 1, 2025, to recover a portion of the 2025 revenue shortfall;
- Interim rate January 1, 2026, to recover a portion of the 2026 revenue shortfall;
- Finalize 2025 and 2026 rates effective April 1, 2026, and approval of any required true-up; and
- Final 2027 rates effective January 1, 2027, to correspond with the removal of YEC's 2023/24 GRA true up rider.

As summarized in Table 1 below and reviewed in Tab 4, the required total rate increase through the end of 2027 is 33.73%. With proposed rate changes timed to provide more bill stability and predictability and coincide with removal/expiry of other charges, this rate increase equates to a 34.3% bill increase for residential customers using 1,000 kWh/ month, and for commercial customers using 3,500 kWh/month effective January 1, 2027, when including the impact of the required true-up.[2]

Table 1: Proposed Rate Changes and Expected Bill Impacts[3]

Proposed Date of Rate Adjustment	Rate increase [Compounded]	Bill increase [Incremental]	Bill increase [Cumulative]
July 1, 2025	10.55%	10.0%	10.0%
January 1, 2026	22.15%	10.0%	20.9%
April 1, 2026	22.15%	6.3%	28.6%
January 1, 2027	33.73%	4.4%	34.3%
Total	33.73%		34.3%

Factors Driving the 2025, 2026 and 2027 Revenue Shortfall

The total rate increase of 33.73% is required to recover a $19.6 million revenue shortfall in 2025, a $33.2 million revenue shortfall in 2026, and a $44.0 million shortfall in 2027. This revenue shortfall reflects the

[2] Without the 2025-27 GRA true-up, the bill impact is about 27% after taking into account removal of the 9.45% 2023/24 GRA true up Rider J1, effective January 1, 2027.

[3] Rate increase represents the technical definition of Revenue Shortfall as compared to the Total Consolidated Firm Sales Revenues at existing rates. Bill increases are shown as both incremental and cumulative. Incremental bill increases are the expected change in bills on the date of the bill adjustment as compared to the day before the bill adjustment. Cumulative bill increases are the change in bills on the date of the bill adjustment as compared to June 30, 2025, the day before the first interim rate change. For April 1, 2026, YEC is not proposing a rate increase, therefore, the compounded rate increase remains the same as January 1, 2026. However, YEC is proposing that the 2025 and 2026 revenue requirement be finalized effective April 1, 2026, resulting in true-up impacts [the incremental bill impact is due to the estimated true-up which is subject to Board's final approvals].

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 are needed now. The factors driving the need for YEC's proposed rates include: (i) sustaining capital requirements and strengthening the power system; (ii) increasing the supply of dependable winter power; and (iii) the impact of rising costs.

- **Sustaining Capital Requirements and Strengthening the Power System:** These investments are required to ensure that Yukon Energy can supply and deliver the amount of electricity it does today and in the future as new sources of electricity and transmission infrastructure are built and connected in the future.

- **Increasing the Supply of Dependable Winter Power**: The Yukon's population grew by 26% between 2014 and 2024. Between 2015 and 2020, peak electricity demands from Yukon homes and businesses (excluding mines) surged by 25%. This upward trend shows no signs of slowing, with non-industrial peak demand projected to rise by 40% by 2030, and 50% by 2035 compared to 2020.

- **Rising Costs:** Like other businesses in Yukon, Yukon Energy 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 also required to direct, plan, execute and oversee the way Yukon Energy responds to today's challenges. These challenges include: the needs of larger projects both in terms of project scope and expenditure; the need for more projects to connect new customer extensions; the requirement to operate a greater number of electricity supply resources; and greater stakeholder expectations and involvement in the way Yukon Energy's 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 Yukon Energy's responsibility to lead these changes. On an isolated grid, these investments are critical. Yukon Energy must ensure there is enough capacity to reliably generate the electricity Yukoners need now and in the future, and cannot import electricity when needed or export power to other jurisdictions when there is a surplus.

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

- Refurbish end of life hydro generation facilities;
- Address challenging and costly requirements related to obtaining renewed licences for existing generating facilities, including increased environmental monitoring associated with these projects;
- 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;
- Adapt to the electrification transition and its impact on winter energy demand; and
- Recover the costs of doing business in an inflationary environment.

Proposed Rider J to Address 2025, 2026 and 2027 Revenue Shortfall

The current level of firm rates results in a revenue shortfall, compared to revenue requirements, as set out in Tab 4. 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)

	2025	**2026**	**2027**
Revenue Requirement	$107,392	$122,406	$134,850
Less: Other Revenues	$413	$413	$413
Less: Secondary Sales	$287	$287	$287
Revenue Required from Firm Rates	$106,692	$121,706	$134,150
Less: Revenues from Firm Sales at Existing Rates [includes Rider J at 2023/24 GRA]	$87,089	$88,505	$90,105
Additional Firm Rate Revenues Required	$19,603	$33,201	$44,045

In accordance with OIC 1995/90 direction, recovery of the Yukon Energy revenue shortfall for the test years would require a Rider J increase of 26.38 percentage points in 2025; 17.53 percentage points in 2026; and a further 13.26 percentage points in 2027 (cumulative total Rider J increase of 57.17 percentage points by January 1, 2027) applicable to all YEC and AEY retail firm rates and all major industrial firm rates.

In order to avoid large true-up impacts for customers, the GRA Application is seeking *interim refundable* Rider J rate increases of 17.89 percentage points for retail and industrial customers effective July 1, 2025; and a further interim refundable Rider J rate increase of 19.66 percentage points effective January 1, 2026.

In order to reduce customer bill volatility, YEC seeks approval of the 2025-27 GRA final rates for the 2025 and 2026 test years and true-up rider, if required, effective April 1, 2026, and final 2027 test year rates effective January 1, 2027. This will enable coordination of the rate increase with the removal of the 2023/24 YEC GRA true-up Rider J1 of 9.45% which is in effect until December 31, 2026.

SUMMARY OF REQUESTED ORDERS

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

1. **2025, 2026 & 2027 Revenue Requirement:** Approval of the forecast revenue requirement of $107.392 million for 2025, $122.406 million for 2026 and $134.850 million for 2027, 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 $20.237 million in 2025, $22.130 million in 2026 and $24.131 million in 2027, 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 kWh to be $0.3219/kWh for diesel and $0.2482/kWh 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 80% LNG and 20% diesel generation, resulting in weighted average thermal cost at $0.2629/kWh.

    b. **Non-Fuel Operating and Maintenance Costs:** Non-fuel operating and maintenance costs forecast of $43.143 million in 2025, $45.678 million in 2026 and $46.750 million in 2027.

c. **Depreciation and Amortization Expenses:** Approval of depreciation and amortization expenses forecast of $20.261 million for 2025, $24.190 million for 2026 and $26.398 million for 2027.

d. **Mid-Year Forecast Rate Base:** Approval of mid-year forecast rate base costs of $408.566 million for 2025, $516.329 million for 2026 and $618.935 million for 2027, including costs for capital works and deferred cost projects brought into service (or forecast to be brought into service) since the 2023/24 General Rate Application.

e. **Return on Rate Base:** Approval of $23.751 million in 2025, $30.408 million in 2026 and $37.571 million in 2027 including an allowed rate of return on equity of 9.15% for each test year.

2. 2025, 2026 and 2027 Interim and Final Rates: Approval of the following rates to recover the 2025, 2026 and 2027 revenue shortfall:

a. **Interim Refundable Rates effective July 1, 2025:** Approval to implement an interim refundable rate rider increase (Rider J) of 17.89 percentage points for retail firm rates (from 55.40% to 73.29%) and industrial firm rates (from 51.75% to 69.64%) effective on an interim refundable basis as at July 1, 2025 (see Tab 4, Appendix 4.1A for proposed interim Rider J rate schedule).

b. **Interim Refundable Rates effective January 1, 2026:** Approval to implement an interim refundable rate rider increase (Rider J) of 19.66 percentage points for retail firm rates (from 73.92% to 92.95%) and industrial firm rates (from 69.64% to 89.30%) effective on an interim refundable basis as at January 1, 2026 (see Tab 4, Appendix 4.1B for proposed interim Rider J rate schedule).

c. **Approval of final Rates for 2025 and 2026 Revenue Requirements:** Following receipt of final orders in this proceeding, including approval of a final 2025, 2026 and 2027 revenue requirements, any residual shortfall or surplus will be addressed pursuant to direction of the Board. In this Application, YEC is proposing the final rates for 2025 and 2026 revenue requirements and any required true-ups are approved effective April 1, 2026.

Based on the Application and excluding any true-up requirements, final Rider J increase of 43.91 percentage points (26.38 percentage points for 2025 and 17.53 percentage points for 2026), and removal of all interim refundable rates, effective April 1, 2026. The Rider J increases are from 55.40% to 99.31% for retail firm rates and from 51.75% to 95.66% for industrial firm rates.

d. **Approval of final 2027 Rates:** Final Rider J increase of 13.26 percentage points (from 99.31% to 112.57% for retail firm rates and from 95.66% to 108.92% for industrial firm rates) for 2027 effective January 1, 2027 to recover the 2027 revenue shortfall [this coincides with the expiration of the 2023/24 GRA true-up rider].

OVERVIEW OF SUPPORTING DOCUMENTS

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

- **Tab 1 Introduction:** Provides an introduction to the supporting documents.
- **Tab 2 Sales and Generation:** Provides detail on the power system operated by Yukon Energy and its forecast sales and generation for 2025, 2026 and 2027 test years.
- **Tab 3 Revenue Requirement:** Provides detailed information on Yukon Energy's total forecast cost of providing service in 2025, 2026 and 2027 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 2025 to 2027 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 2023/24 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 the 2025, 2026 and 2027 test years.

- **Tab 9 Net Salvage Study:** Provides a copy of the Net Salvage Study.

- **Tab 10 Audited Financial Statements:** Provides a copy of Yukon Energy's audited financial statements for 2023.

- **Tab 11 Orders in Council:** Provides relevant Orders in Council which direct the Board regarding certain aspects of Yukon Energy's revenue requirement and rate design.

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INTRODUCTION

1.0 INTRODUCTION

Yukon Energy Corporation's (YEC or Yukon Energy) 2025-27 General Rate Application (the GRA or Application) includes 11 tabs of supporting documents related to Yukon Energy's operations, revenue requirements for the 2025, 2026 and 2027 test years, and requested approvals.

Tab 1 introduces the supporting documents, and reviews the following:

- Context and Approach for Current Application;
- Drivers of 2025, 2026 and 2027 Rate Increases;
- Other Regulatory Issues; and
- Electricity Rates and Bills.

1.1 CONTEXT AND APPROACH FOR CURRENT RATE APPLICATION

1.1.1 Background on Yukon Energy Corporation

Yukon Energy was established in 1987. It is a publicly owned electrical utility that operates as a business, at arm's length from Yukon government (YG). Yukon Energy is the main generator and transmitter of electrical energy in the Yukon providing approximately 97% of the total electricity generation on the Yukon Integrated System (YIS).[1]

There are over 23,000 electricity consumers in the territory. Yukon Energy directly serves over 2,700 of these customers, most of whom live in and around Dawson City, Mayo and Faro, and other small communities in southern Yukon (Mendenhall, Aishihik, Champagne, Braeburn, Johnson's Crossing, South Fox, Little Fox, Little Salmon, Drury Creek, Pine Lake, Canyon Creek, and McGundy). Indirectly, Yukon Energy provides power to most other Yukon communities through ATCO Electric Yukon (AEY). AEY buys wholesale power from Yukon Energy and sells it to retail customers.

[1] Based on 2024 preliminary actuals as the total YEC generation out of the total electricity generation on YIS, including AEY Fish Lake and Independent Power Producers (IPPs), but excluding microgeneration.

Most of the electricity Yukon Energy 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 and Yukon Energy cannot import electricity when needed or export power to other jurisdictions when there is a surplus. For Yukon Energy and Yukoners, this means Yukon Energy only has itself to rely on to ensure it has an adequate and dependable supply of electricity to meet Yukoners' demands for power on cold winter days and in the future. Right now, on an average day in winter, homes and businesses (excluding mines) use about 80% of all the power Yukon Energy can generate during peak times.[2]

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

- High growth in non-industrial winter peak demands for electricity, the related ongoing challenge of providing new dependable winter capacity to supply homes and businesses, and the resulting impacts on needed investments, diesel rentals, staff resources, and overall Yukon Energy costs. Winter demand for power in the Yukon is nearly three times higher than demand in the summer.
- Fluctuating industrial loads and related impacts on Yukon Energy revenue requirements to be recovered from residential and commercial (i.e., general service) customers.
- A surplus of renewable summer energy that does not currently provide benefits to Yukon customers, and a shortage of renewable winter resources to provide dependable winter electrical capacity needed.
- A power system with equipment that is aging, with major ongoing investment, staff, and other operating resource requirements for Yukon Energy.

[2] Based on a winter day at an average temperature of -19 degrees Celsius. Measured in megawatts (MW).

- Increasing pressure on the electricity system stemming from population growth, increased use of electricity by homes and businesses, and the connection of distributed energy sources across the territory.

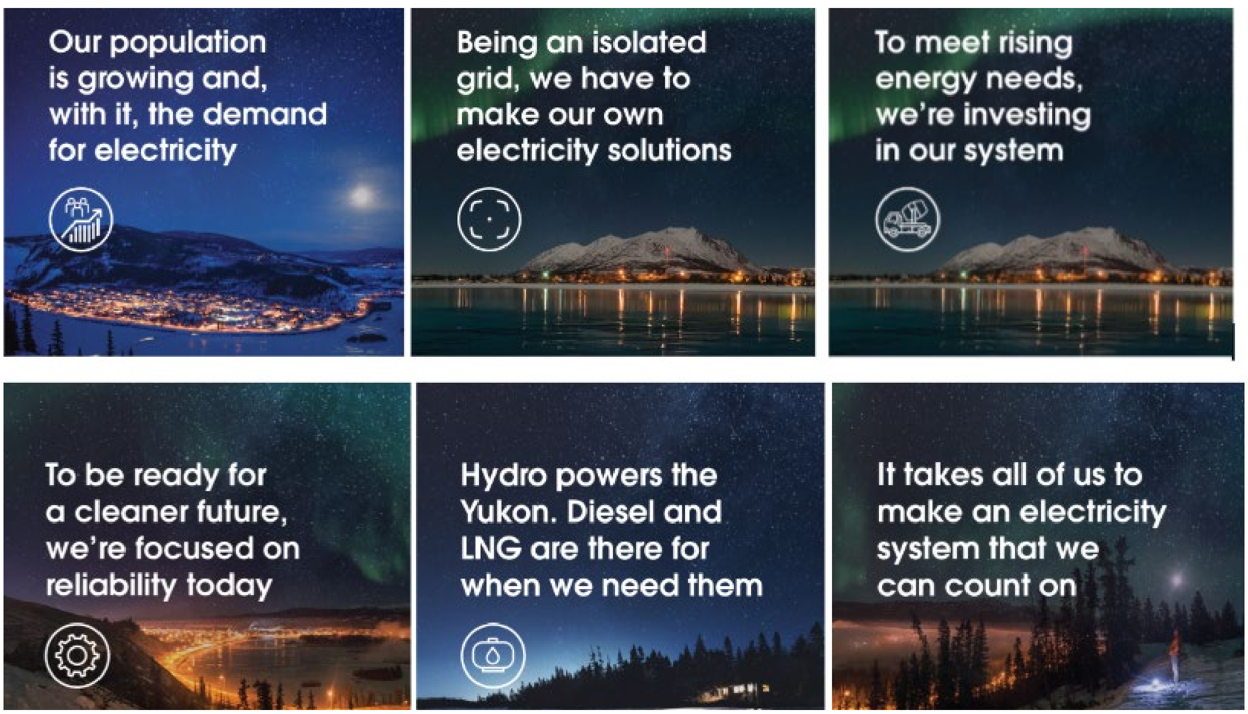
- A power system with generating stations that require renewed permits and authorizations at a time when regulatory processes are becoming more complex and costly.

- A small customer base without economies of scale for large investments.

- Increased competition for government funding and grants.

These challenges were highlighted in the January 2025 social media campaign released by Yukon Energy to Yukoners about the current state of our grid.

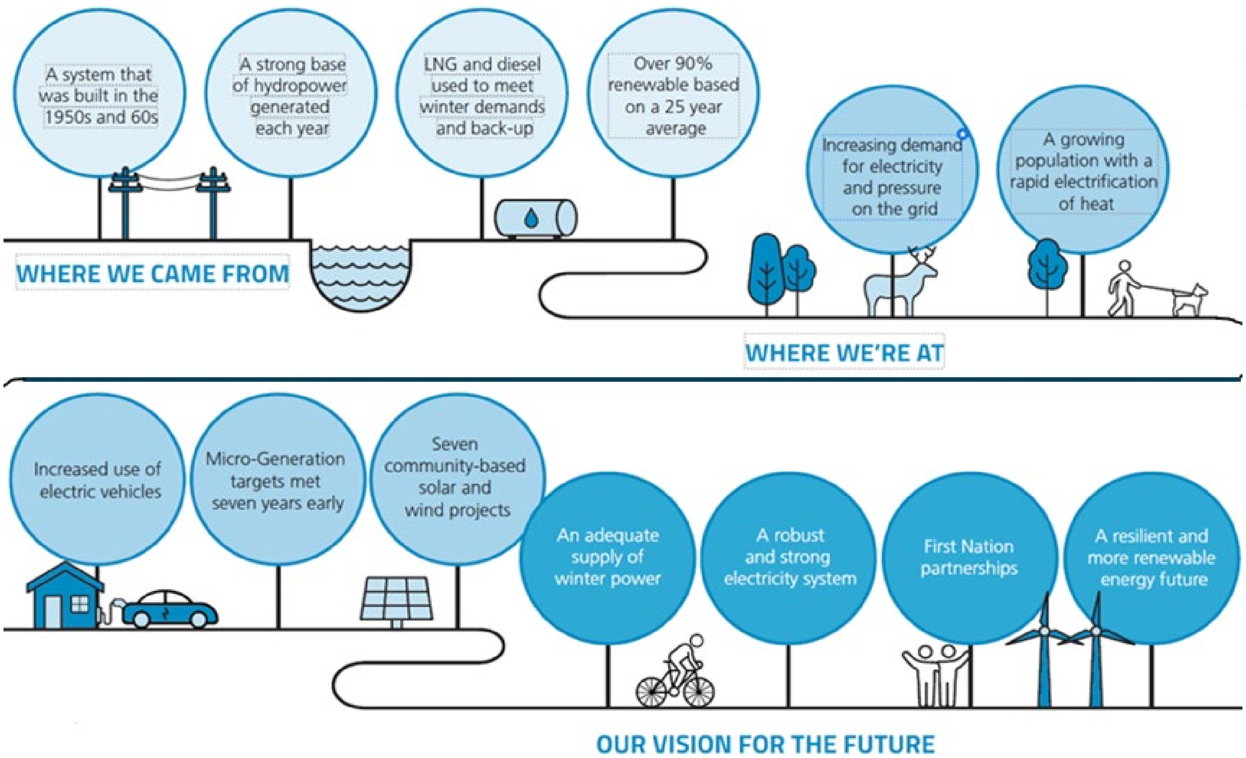
Figure 1-1: Summary of Yukon Energy Challenges



1.1.3 Building a Resilient and Renewable Energy Future

Yukon Energy's path to the future is clear: a robust, resilient and more renewable electricity system by 2050. Yukon Energy has released a road map for the next 25 years that unfolds in three stages, each advancing at its own pace and building on the success of the one before. The first stage is about building a reliable and robust grid, outlining the decisive steps to be taken in the next five years to provide Yukoners with an adequate and dependable supply of electricity, build a stronger power system, and build the plans and partnerships needed to support future renewable sources of electricity. Future stages will outline how the Yukon's power system will be shaped into one that's modern, flexible and resilient.

Figure 1-2: Yukon Energy Roadmap for the Next 25 Years



One thing is certain – the demand for electricity is growing. As the Yukon's population increases, and the Yukon continues to transition away from fossil fuels for heating and transportation, demand will only increase. Ensuring an adequate and dependable supply of electricity for Yukoners today and into the future requires a clear focus on:

- Re-investing in our existing hydro facilities – the renewables we depend on today – and the existing electricity system;
- Increasing the capacity of our grid and the supply of electricity we can depend on during the winter;
- Reducing winter demands for power; and

- Strengthening our electricity system by building critical infrastructure like substations, transmission loops and new power lines to provide redundancy to current assets.

This means that Yukon Energy will be:

- Renewing licences and permits for existing hydro, LNG and diesel power plants;
- Replacing generation and transmission infrastructure and equipment that is nearing end-of-life;
- Increasing supply of winter capacity resources, and strengthening existing transmission and distribution systems to allow more power to flow to communities;
- Balancing resources in the North and South Yukon to meet community needs in the event of emergencies;
- Reducing the environmental and socio-economic impacts of existing power production;
- Continuing to deliver Demand Side Management (DSM) programs to shift electricity use and reduce peak demands for power; and
- Working with partners to research and assess potential energy solutions for the future.

A stronger, more robust grid is necessary to meet growing electricity demands, safely integrate the next generation of community renewables, and provide consumers with more options to better manage their electricity use.

1.1.4 Yukon Energy's Short-Term Action Plan

Over the next five years, Yukon Energy will be working to address the Yukon's critical electrical energy and capacity needs.

The capacity (or size) of the Yukon's main electricity system is 162 megawatts.[3] Most of this capacity is from the three hydro facilities in Whitehorse, Mayo and Aishihik, as well as the LNG and diesel power plants that Yukon Energy and AEY have in on-grid communities across the territory. The dependable capacity of these power plants decreases in the winter months to 131 megawatts because of lower water levels and downstream flow restrictions required to prevent flooding.[4]

Yukon Energy rents diesel generators each winter to heat homes and keep electricity running during cold days, and to fill the gap between the amount of power Yukon homes and businesses (excluding mines) need during peak times and the amount of power Yukon Energy is able to generate using its own resources during an emergency. For planning purposes, Yukon Energy defines an emergency as the loss of the Aishihik Generating Station, its largest source of winter power.

During the Winter of 2024/2025, Yukon Energy rented 22 diesel units (nearly 40 megawatts) to fill the power gap and located those units in Whitehorse, Faro and Mayo. Based on current forecasts, without any new dependable generation, by 2035 Yukon Energy will need double the number of rented diesel units during the winter to meet peak demands for power and protect against prolonged outages during an emergency.

Growing demand for electricity today is occurring throughout Canada. In a recent publication by Electricity Canada, *Electricity is Essential for the Next Decade*, it states that "In the next 25 years, Canada's electricity demand could more than double, from approximately 600 TWh/yr to over 1200 TWh/yr. Doing this requires building projects on a massive scale. Growing communities will need to be connected to sources of power. Distribution networks will need to be expanded and modernized to efficiently distribute and re-distribute power… There is a great deal at stake. The financial cost of getting this wrong is too great. A decision made today needs to hold up 20, 30 and even 40 years from now."[5]

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[3] Based on nameplate capacity for 2027/28 (see Tab 2, Table 2.3). Summer and winter capacity (i.e., output) of the grid is less than the nameplate capacity of the grid. Does not include rental diesels and IPPs. Includes ATCO diesel and capacity from currently committed projects, such as diesel replacements in Faro and Whitehorse, new diesel units in Callison, battery storage, and demand-side management programs.

[4] Dependable capacity for winter 2027/28 (see Tab 2, Table 2.3). Excluding rental diesel units, this includes all hydro, thermal and other facilities included in the 162 MW capacity of the Yukon Integrated System. Adjustments reflect impact of lower winter water levels, downstream flow restrictions required to prevent flooding, and Forced Outage Rate reductions for effective load carrying capacity.

[5] https://www.electricity.ca/electricity-is-essential-the-state-of-the-canadian-electricity-industry-2025/#:~:text=Electricity%20is%20essential.&text=In%20the%20next%2025%20years%2C%20Canada's%20electricity%20demand%20could%20more,a%20lot%20to%20get%20done.

Demand for power is expected to grow the fastest in the Yukon's major load centre – Whitehorse. As a result, Yukon Energy's plan is to install the new winter capacity needed in and around the Whitehorse area. At the same time, Yukon Energy plans to move some of the thermal resources that exist in the North Yukon region closer to Whitehorse. This will help us ensure that Yukoners have an adequate and balanced supply of winter power in both the North Yukon and South Yukon regions. This type of regional planning is crucial in the event that an issue causes our electricity system to split and supplies of power in the North and South regions cannot be delivered to each other.

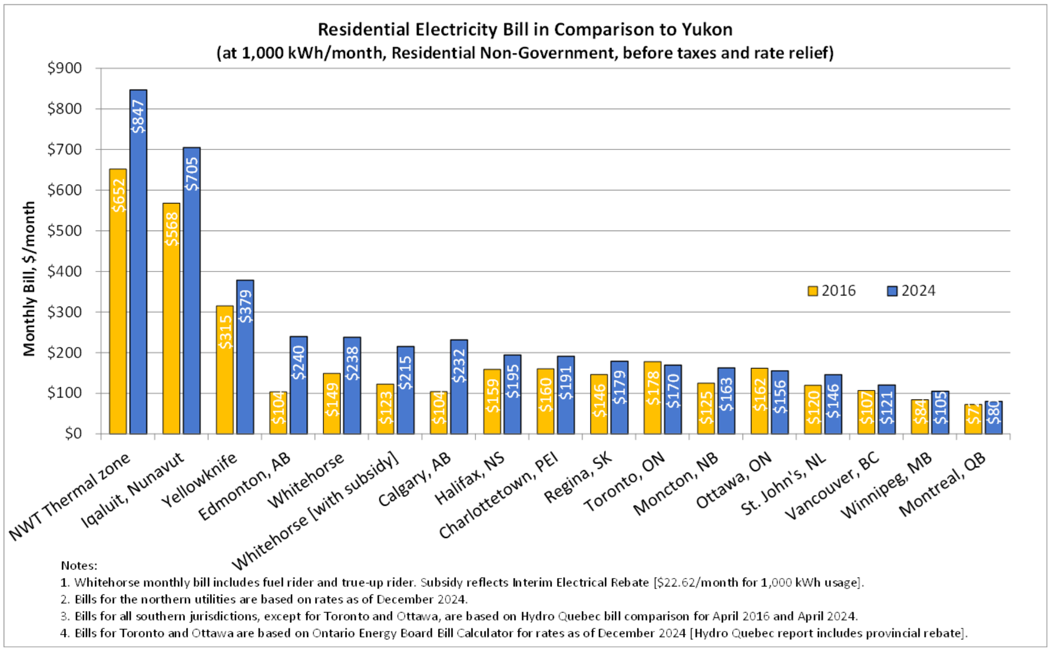
In the short term, Yukon Energy will be increasing thermal resources, as Yukoners need dependable capacity now, and adding critical pieces of infrastructure to our grid, primarily in and around Whitehorse. Thermal resources are the fastest and most cost-effective solution to meet current needs, and Yukon Energy is firmly committed to providing Yukoners with electricity they can count on today to fuel their homes, businesses, hobbies and interests. At the same time, Yukon Energy is championing renewables by reinvesting in existing hydro resources and strengthening the grid to support the next generation of community renewables. In the next 12 to 24 months, Yukon Energy, together with our shareholder, the Yukon Development Corporation (YDC), plan to issue one or more Calls for Power to build new community renewables that will help us reduce our reliance on thermal resources. Specifications for those Calls for Power have not been determined yet.

While Yukon Energy's long-term goal is to create a robust, resilient and more renewable electricity system, the focus today is on ensuring an adequate and dependable supply of electricity and a robust transmission system is available to meet the growing demands for power Yukoners have today and in the next 5 to 10 years. At the same time, these projects are necessary to provide the foundation for a modern and adaptable electricity system, one that can integrate more community-based sources of intermittent renewables and emerging technologies as Yukoners' electricity needs continue to evolve. Ongoing investment in infrastructure and winter capacity will be crucial to meeting immediate power needs and supporting renewable energy growth.

1.1.5 Rate and Bill Comparisons

Yukon's 2016 and 2024 residential bills are shown below in comparison to other cities across Canada.

Figure 1-3: Residential Electricity Bill Comparison to Yukon



- Figure 1-3 indicates that Whitehorse has the lowest electricity bills in the North, and electricity bills that are comparable to some southern cities.

- The gap in the North is expected to grow as Northwest Territories Power Corporation (NTPC) and Qulliq Energy Corporation (QEC) have recently filed rate applications seeking proposed rate increases that are greater than the effective annual rate increase proposed in Yukon Energy's current application. Specifically, NTPC has submitted an application for a rate increase of 24%[6] over two years and QEC (Nunavut) has filed a GRA seeking a 14.1%[7] rate increase for one test year. [8]

Applications for rate increases are also being made by electrical utilities in order to make the investments needed in other jurisdictions.

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[6] NTPC 2024-26 GRA Application, page 1-6 (lines 16-20), Table 1.1 Schedule 3.0, pdf pg 65 https://nwtpublicutilitiesboard.ca:81/Documents/NTPC%202024-26%20GRA%20Phase%20I.pdf

[7] QEC 2025/26 GRA, page 5-3 (lines 10-13), Table 5.3 at https://www.qec.nu.ca/sites/default/files/2025-26%20QEC%20GRA%20-%20Master-Final.pdf

[8] Yukon Energy is seeking 33.73% for three years, or approximately 10.17% per year with compounding impact, while NTPC's GRA is 24% over two years, or 11.36% per year with compounding impact, and Nunavut is seeking 14.1% for only one fiscal year.

- New Brunswick Power rates increased by 9.7% effective April 1, 2024, and further 9.7% increase was approved effective April 1, 2025.[9]
- Newfoundland Power had an overall average rate increase of 7.0% effective August 1, 2024 with further increase expected effective July 1, 2025.[10]
- Yukon Energy, through discussions with other utilities in the Canadian Electricity Association, has been notified that two major southern utilities plan on filing applications with rate increases of 50% over the next five years.[11]

1.1.6 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. Yukon Energy's currently approved Return on Equity (ROE) is 9.15%. This level of ROE provides Yukon Energy with the equity capital needed to replace aging infrastructure and invest in critical electricity supply and transmission 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, Yukon Energy would not be able to earn enough revenue to cover annual business costs and make the investments needed each year. Yukon Energy forecasts:

- A revenue shortfall of approximately $16.5 million[12] and ROE of -0.84% in 2025;
- A revenue shortfall of approximately $29.7 million and ROE of -5.24% in 2026; and
- A revenue shortfall of approximately $40.2 million and ROE of -7.08% in 2027.

[9] https://www.nbpower.com/en/about-us/regulatory/rate-application/rate-decision/,
[10] https://www.newfoundlandpower.com/My-Account/Usage/Electricity-Rates and http://www.pub.nl.ca/applications/NP2025GRA/app/From%20NP%20-%202025-2026%20General%20Rate%20Application%20-%20Volume%201%20-%202023-12-12.PDF.
[11] The names of the specific utilities have not been published due to confidentiality until rate applications have been submitted by those utilities.
[12] Without the GRA, the fuel cost increase of $3.1 million in 2025 would have been recovered through Rider F rather than the rate increase. Therefore, the revenue shortfall is $16.5 million for 2025 without GRA compared to the 2025 test year shortfall of $19.6 million with fuel cost increase included. The same applies to the other test years.

Such revenue deficiencies are far below a fair return on equity and would not satisfy the requirements of *Rate Policy Directive (1995)*, OIC 1995/90 (as amended). Not addressing these significant revenue deficiencies would make it extremely challenging to maintain existing infrastructure, meet Yukoners' increasing demands for power, and put the safety and reliability of the existing electricity system at risk.

1.1.7 Approach for the Current Rate Application

Yukon Energy's approach for timing of rate increases is based on feedback received during and since the previous GRA. Yukon Energy has heard from intervenors that ratepayers value predictability (understand timing for rate changes) and stability (i.e., want to know rates in advance, want smooth rate increases across the test years, and to avoid or minimize rate true-ups). As detailed in Tab 4, Yukon Energy is requesting incremental rate increases on July 1, 2025, January 1, 2026, April 1, 2026 and on January 1, 2027, to allow it to continue to provide Yukoners with an increasing supply of safe, reliable and sustainable electricity. Yukon Energy is seeking approval of interim rate increases and final rate adjustments to occur at the earliest possible time within a test year, and when other charges are expected to be removed from bills. This would reduce the impact of rate increases, providing greater bill stability and predictability for Yukoners.

As outlined in further detail below, rate increases are required to recover the cost of significant and necessary investments in all aspects of Yukon's electricity system.

Through feedback received during and since past GRAs, Yukon Energy understands that there has been confusion with technical terms used in its applications such as rate increases, Rider J increases, and bill impacts.[13]

- Rate increases represent the technical definition of the Revenue Shortfall as compared to the Total Consolidated Firm Sales Revenues at existing rates.

- Bill increases are shown as both incremental and cumulative.

[13] The rate increase is calculated on overall consolidated revenues which includes YEC Rider J and AEY Rider R; while Rider J is only applied to the base rates [energy, customer charge, demand charge], therefore, the requested Rider J is higher than the rate increase to recover the same amount of shortfall.

- Incremental bill increases are the expected change in bills on the date of the bill adjustment as compared to the day before the bill adjustment.

- Cumulative bill increases are the change in bills on the date of the bill adjustment as compared to June 30, 2025, the day before the first interim rate change.

A GRA is a very technical regulatory process and must include technical information such as rate changes or Rider J changes. However, information regarding bill impacts is also provided in this GRA as this is often more meaningful for ratepayers and shows the actual impact that ratepayers see on their monthly bills.

It is important to note that bills can be impacted materially by the timing of rate increases resulting from a GRA.

Rate changes requested in this GRA seek to recover the forecast revenue shortfalls noted earlier. The Board needs time to review the application and issue a final decision; however, its final decision also needs to recover the approved revenue shortfalls in each year, including shortfalls during the time needed for the Board's review process. If no rate change occurs until the Board's decision, anticipated in 2026, the required increase will need to include catch up (or "**true up**") for revenue shortfalls in 2025 and the time used to date in 2026, as well as recover the revenue shortfalls going forward. This would result in a much larger increase to electricity bills in 2026 as compared to if an interim rate adjustment was made in 2025 as proposed. To reduce the need for large, catch-up bills when the final decisions occur, interim rate increases have been approved in the past by the Board before its final rate decisions.

In general, the earlier the interim rates are approved and implemented during a GRA review, the lower the overall bill increase that results as it spreads the rate increase over a larger number of months and minimizes the required true-up at the end. This is one of the reasons Yukon Energy proposes higher interim rate requests in this Application.

As explained later in Table 1-4, Yukon Energy needs an overall increase in rates of 33.73% by 2027 to recover the revenue shortfall in 2027. Impacts on customer bills going forward will depend on the timing and magnitude of interim rate increases before 2027. The tables below show the bill impact of the requested rate increase of 33.73% over three test years under different options for interim rates, using the average (non-government) residential bill impact for 1,000 kWh/month consumption as an example considering most of the ratepayers in the Yukon are residential customers.

Three options are presented to show different impacts for different levels of interim rates: Option 1 shows bill impacts with interim rate changes that assume the Board approves the amount and timing of rate changes as proposed in Tab 4 of this Application, while options 2 and 3 provide alternative bill adjustments as summarized below and in Tab 4. All three options assume a compounded rate increase of 33.73% over three years, however, the bill impacts vary due to the timing of the interim rate increases as well as resulting required true ups which also vary significantly depending on the amount and timing of rate increases. The table includes bill impacts from the 2023/24 GRA true up rider of 9.45% which expires on January 1, 2027.

Option 1 (Bill Smoothing) – The goal of this option, which is proposed in this Application, is to minimize the required true-up needed at the time of the Board's Decision, while providing relatively smooth bill adjustments. Under this option, the bills increase by 10% on July 1, 2025 (about 2/3 of the 2025 increase), 10% on January 1, 2026 (about 85% of the 2026 increase), 6.3% on April 1, 2026 (2025/26 true-up) and 4.4% on January 1, 2027 (final rates for 2027 test year). The total three-year bill impact is $83.62 (or 34.3%) for typical residential customers using 1,000 kWh/month. The extent that the cumulative bill impact in 2027 at 34.3% is higher than the 33.73% compounded rate increase reflects the net impact of this GRA's true up relative to the expired true up from the 2023/24 GRA.

Table 1-1: (Option 1 - Bill Smoothing)[14]

Proposed Date of Rate Adjustment	Rate increase [Compounded]	Bill increase [Incremental]	Bill increase [Cumulative]	Monthly Bill[15]
June 2025				$243.84
July 1, 2025	10.55%	10.0%	10.0%	$268.18
January 1, 2026	22.15%	10.0%	20.9%	$294.92
April 1, 2026	22.15%[16]	6.3%	28.6%	$313.62
January 1, 2027	33.73%	4.4%	34.3%	$327.46
Total	33.73%		34.3%	

Option 2 (Summertime Interim Increases) – The goal of this option is to avoid interim winter increases. Under this option, the bills increase by 14.7% on July 1, 2025 (100% of the 2025 increase), 15.9% on April 1, 2026 (100% of the 2026 increase plus true-up for 2025 and 2026 test years[17]), and

[14] Excludes AEY's Rider R1 which is currently under review by the Board based on AEY's application.
[15] Excludes GST and prior to any government rebates.
[16] Under options 1 and 3, there is no incremental rate increase for April 1, 2026; the bill changes are solely due to the estimated true-up, which is subject to final approved revenue requirements and the timing of approved interim rates.
[17] True-up for 2025 is required for January 1 through June 30, 2025 and for 2026 it is required for January 1 through March 31, 2026.

1.6% on January 1, 2027 (final rates for the 2027 test year). The total three-year bill impact is $85.58 (or 35.1%) for typical residential customers using 1,000 kWh/month [slightly higher true-up than for option 1 due to delayed implementation of the 2026 rates].

Table 1-2: (Option 2 - Summertime Interim Increases)

Proposed Date of Rate Adjustment	Rate increase [Compounded]	Bill increase [Incremental]	Bill increase [Cumulative]	Monthly Bill
June 2025				$243.84
July 1, 2025	15.57%	14.7%	14.7%	$279.74
January 1, 2026	15.57%	0%	14.7%	$279.74
April 1, 2026	25.91%	15.9%	33.0%	$324.24
January 1, 2027	33.73%	1.6%	35.1%	$329.42
Total	33.73%		35.1%	

Option 3 (Minimize True-Up) - The goal of this option is to minimize the required true-up while assuming that July 1, 2025 is the earliest date for the initial interim rate. Under this option, the bills increase by 14.7% on July 1, 2025 (100% of the 2025 increase), 8.5% on January 1, 2026 (100% of the 2026 increase), 3.4% on April 1, 2026 (true-up for 2025[18]) and 1.6% on January 1, 2027 (final rates for 2027 test year less removal of 2023/24 GRA true-up of 9.45%). The total three-year bill impact is $75.38 (or 30.9%) for typical residential customers using 1,000 kWh/month; due to the minimizing of this GRA's true-up and removal of the prior GRA true-up, this cumulative bill increase is less than the 33.73% compounded rate increase.

Table 1-3: (Option 3 - Minimize True-Up)

Proposed Date of Rate Adjustment	Rate increase [Compounded]	Bill increase [Incremental]	Bill increase [Cumulative]	Monthly Bill
June 2025				$243.84
July 1, 2025	15.57%	14.7%	14.7%	$279.74
January 1, 2026	25.91%	8.5%	24.5%	$303.59
April 1, 2026	25.91%[19]	3.4%	28.8%	$314.04
January 1, 2027	33.73%	1.6%	30.9%	$319.22
Total	33.73%		30.9%	

[18] True-up is required for 2025 for January 1 through June 30, 2025.
[19] Under options 1 and 3, there is no incremental rate increase for April 1, 2026; the bill changes are solely due to the estimated true-up, which is subject to final approved revenue requirements and the timing of approved interim rates.

There is rationale to accept any of the above three options. However, Yukon Energy is proposing Option 1 as it provides the smoothest bill adjustments over the test years.

1.1.8 Rate Mitigation Strategies

Government Grant Funding

Yukon Energy is acutely aware that utility costs not offset by government funding or third-party investment are included in electricity rates, and that even the smallest of rate increases can have a significant impact on some customers. In an effort to limit the impact of Yukon Energy's investments on electricity rates, Yukon Energy is pursuing opportunities for funding.

Yukon Energy has sought $50 million in federal grant funding through NRCan's *Smart Renewables and Electrification Pathways Program's (SREPs') Utility Support Stream (USS)* to offset the cost of a portion of its capital investments between 2025-2027. The SREP USS supports utilities and system operators in modernizing their systems and integrating renewables while maintaining reliability and affordability. An Expression of Interest to fund projects found in this 2025-2027 GRA was submitted to NRCan on December 13, 2024, with a follow-up Full Project Proposal submitted on April 2, 2025, representing approximately $25 million of the $50 million sought. Yukon Energy is awaiting information from NRCan about whether it's application for funding was successful. Yukon Energy expects to submit an additional Full Project Proposal for other projects later in 2025 for the remainder of the maximum $50 million program funding allowed.

Yukon Energy is also supporting Yukon Development Corporation's funding request from the SREP Critical Regional Priorities Stream, as well as funding specifically related to the Mayo Rock Slope Remediation and Surge Chamber projects.

If successful, contributions provided would partially offset total costs for specified projects. Yukon Energy will update the Board regarding the status of the Applications as information becomes available.

First Nation Partnerships

Yukon Energy acknowledges that the historical development of Yukon hydro facilities has had ongoing and lasting effects on both the environment and Yukon First Nations. Today, Yukon Energy is actively conducting studies, adjusting operations and implementing mitigation strategies to reduce the environmental and socio-economic impacts of these existing facilities. Work to relicense Mayo, Whitehorse and Aishihik hydro facilities reinforces that agreements with First Nations provide a powerful example of the positive outcomes that can be achieved through meaningful partnerships and collaboration.

Building a reliable and robust grid means taking a new approach – one that considers the needs and values of the communities we serve. As a public utility, we strive to fulfill commitments as outlined in Chapter 22 of the Umbrella Final Agreement including economic development, employment, procurement and investment, amongst others. Our relationship with First Nations governments and businesses is vital to our success, and we deeply value the trust, knowledge and expertise that these partnerships bring. We look forward to strengthening these ties and working together to build an electricity system that we can all count on.

Yukon First Nations may become involved in the electricity sector through partnering with Yukon Energy on utility-led projects and/or investing in new electricity supply projects located in their Traditional Territory.

1.2 DRIVERS OF 2025, 2026 AND 2027 RATE INCREASES

If there were no GRA, Yukon Energy forecasts that revenue earned in 2027 (using rates approved in Yukon Energy 2023/24 GRA plus ongoing Rider F adjustments for fuel price changes) would be $40.2 million short of the revenue needed to cover Yukon Energy business costs and investments that year (2027). To cover these costs, as well as current fuel price costs, Yukon Energy is applying for a 33.73% increase in rates over the three-year period (2025, 2026 and 2027).

Table 1-4 summarizes by cost components the 2025, 2026 and 2027 GRA revenue shortfalls and contributions to proposed rate increases. The key drivers for the rate increase (by cost element) include:

- **Capital cost increases** ($28.0 million of the total $44.0 million shortfall,[20] or 21.44% of the 33.73% total rate increase. Represents about 64% of the total 2027 shortfall).

[20] The $44.0 million shortfall in 2027 includes fuel price change impacts of $3.851 million that ongoing Rider F adjustments for fuel price changes would recover without this GRA, i.e., as noted above, revenue earned in 2027 without any GRA would be $40.2 million short of the revenue requirement ($44.0 million less $3.851 million for fuel price Rider F adjustments that can occur with or without the GRA).

- **Non-fuel O&M increases** ($9.4 million of the total $44.0 million shortfall, or 7.23% of the 33.73% total rate increase. Represents about 21% of the total 2027 shortfall).

- **Fuel price increases since the 2023/24 GRA** ($3.8 million of the total $44.0 million shortfall, or 2.95% of the 33.73% total rate increase. Represents about 9% of the total 2027 shortfall).

- **Other factors** such as changes in energy and peak load as well as purchases from power producers ($2.8 million of the total $44.0 million shortfall, or 2.12% of the 33.73% total rate increase. Represents about 6% of the total 2027 shortfall).

Table 1-4:
Summary of Revenue and Cost Changes – 2024 Approved vs 2025, 2026 and 2027 GRA

2025-27 Revenue Shortfall Drivers	2025 GRA over 2024 Approved ($000)	% share of 2025 Rate Increase	2026 GRA over 2024 Approved ($000)	% share of 2026 Rate Increase	2027 GRA over 2024 Approved ($000)	% share of 2027 Rate Increase
Capital Costs	**8,036**	**6.38%**	**18,622**	**14.53%**	**27,993**	**21.44%**
Depreciation (fixed asset increases)	*5,658*	*4.49%*	*9,530*	*7.44%*	*12,659*	*9.69%*
Deferred costs amortization	*1,661*	*1.32%*	*2,143*	*1.67%*	*1,548*	*1.19%*
Amortization of Customer Contributions	*-1,761*	*-1.40%*	*-2,186*	*-1.71%*	*-2,512*	*-1.92%*
Long-term debt cost - rate base change	*1,460*	*1.16%*	*5,279*	*4.12%*	*9,035*	*6.92%*
ROE increase - rate base change	*1,018*	*0.81%*	*3,856*	*3.01%*	*7,263*	*5.56%*
Energy & Peak Load Changes	**1,926**	**1.53%**	**2,021**	**1.58%**	**2,021**	**1.55%**
Reduced revenue impact at existing rates	*3,555*	*2.82%*	*2,139*	*1.67%*	*540*	*0.41%*
Long Term Average (LTA) thermal cost [1]	*-1,630*	*-1.29%*	*-118*	*-0.09%*	*1,481*	*1.13%*
Fuel Price Changes[2]	**3,137**	**2.49%**	**3,484**	**2.72%**	**3,851**	**2.95%**
Non-Fuel O&M Costs	**5,828**	**4.63%**	**8,364**	**6.53%**	**9,435**	**7.23%**
Labour cost increase	*1,873*	*1.49%*	*3,398*	*2.65%*	*4,466*	*3.42%*
Non-labour O&M [3]	*3,955*	*3.14%*	*4,966*	*3.87%*	*4,970*	*3.81%*
IPP Power Purchase Cost	**676**	**0.54%**	**710**	**0.55%**	**744**	**0.57%**
Total Revenue Shortfall	**19,603**	**15.57%**	**33,201**	**25.91%**	**44,045**	**33.73%**
Required Rate Increase [Compounded]	15.57%		25.91%		33.73%	

Notes:
1. Excludes LTA fuel price impact [shown separately].
2. Fuel price impact compared to the 2023/24 GRA for total LTA thermal change.
3. Includes incremental Diesel Rental cost.

The Application describes three main factors influencing the 2025, 2026 and 2027 revenue shortfall.

1. **Sustaining Capital Requirements and Strengthening the Power System:** These investments are required to ensure that Yukon Energy can supply and deliver the amount of

electricity it does today and in the future as new sources of electricity and transmission infrastructure are built and connected in the future. These investments include upgrading and replacing existing electricity assets, while at the same time renewing licences and permits for Yukon Energy's existing generation facilities. The following cost increase components reflect this sustaining capital requirements cost drivers:

- **Capital Costs rate base additions**[21] – Approximately $204 million for multiple major capital projects being completed between 2025 and 2027 (see Tab 5, Section 5.2.1), led by over $180 million related to ensuring the ongoing ability to generate hydro power at the Mayo hydro facility.

- **Deferred Cost rate base additions** – Approximately $34 million in costs of deferred cost projects are proposed to be added to rate base, with about $28 million on renewable energy (hydro) licensing projects (see Tab 5, Section 5.3.1).

- **Overhaul Capital Costs** – Approximately $10 million from 2025 to 2027 to extend the life of a number of Yukon Energy's existing hydro units (see Tab 5, Section 5.2.1 and Section 5.2.2).

- **Non-fuel O&M Costs** – Increases in environmental monitoring associated with relicensing and required by regulators to approximately $1.0 million as part of Yukon Energy's renewed air emissions permits and water use licenses (see Tab 3, Section 3.3.5).

2. **Increasing the Supply of Dependable Winter Power:** The Yukon's population grew by 26% between 2014 and 2024. Between 2015 and 2020, peak electricity demands from Yukon homes and businesses (excluding mines) surged by 25%. This upward trend shows no signs of slowing, with non-industrial peak demand projected to rise by 40% by 2030, and 50% by 2035 compared to 2020. The following 2024 revenue requirement increase cost components reflect the winter peak demand growth cost driver:

- **Capital Costs rate base additions**[22] – $79.0 million for major capital projects completed between 2025 and 2027 (see Tab 5, Section 5.2.1), including Thermal Replacement at

[21] Major capital cost projects impacting test year rate base are identified without breaking out capital cost factors in Table 1-4, e.g., depreciation, amortization, return on rate base.
[22] Major capital cost projects impacting test year rate base are identified without breaking out capital cost factors in Table 1-4, e.g., depreciation, amortization, return on rate base.

$44.0 million (Callison and Whitehorse diesels), and the Battery Energy Storage System (BESS) at $34.957 million (before contributions of $16.500 million) (see Tab 5, Section 5.2.1).

- **Demand Side Management (DSM)[23] additions** – $1.6 million for DSM deferred cost programs related to reducing dependable capacity requirements (see Tab 5, Section 5.3.2).

- **Non-fuel O&M Costs** – Incremental price and cost increases (approximately $0.600 million) to rent the additional mobile diesel units needed to ensure an adequate and dependable supply of winter power is available during an emergency (see Tab 3, Section 3.3.2).

3. **Rising costs:** Like other businesses in the Yukon, Yukon Energy is not immune to external pressures such as inflation, increased labour costs, and supply chain delays and constraints experienced in recent years. Additional resources are also required to direct, plan, execute and oversee the way Yukon Energy responds to today's challenges. These challenges include: the needs of larger projects both in terms of project scope and expenditure; the requirement to operate a greater number of electricity supply resources; and the greater stakeholder expectations and involvement in the way Yukon Energy's work is done. The following cost components reflect the rising costs and project complexity cost driver:

- **General Inflation** – Yukon Energy and the Yukon have experienced, and are expected to continue to experience, inflation in the test years.

- **Changes for fuel prices** – $3.8 million added to 2027 costs due to rate/price increases for fuel and a change in the expected long-term average fuel mix (see Tab 3, Section 3.1.1 and Appendix 3.3). Fuel price changes would be addressed by Rider F if there was no GRA.

[23] Previously, some intervenors raised questions about supply side management work that YEC is doing in addition to demand side management. Supply side management concentrates on optimizing the generation, transmission, and distribution of electricity and many projects in this Application and prior applications are intended to do so. Some specific examples are: WH2 uprate that increased the efficiency of the hydro unit, BESS that will help to optimize the system, and the Dawson voltage conversion project.

- **Non-fuel O&M Labour Costs** – Yukon Energy added labour costs (both the increase in salaries and staffing requirements – see Tab 3, Section 3.1.1).

- **Non-fuel O&M Non-Labour Costs** – Information Technology (IT) and Operating Technology (OT) System and costs needed to connect a greater number of assets across the territory and address increased cybersecurity risks.

1.3 OTHER REGULATORY ISSUES

Aside from the need to address revenue requirement shortfalls at existing rates, the current Application does not identify other regulatory issues that need to be addressed concurrently with the Application.

1.4 YUKON ENERGY RATES AND BILLS

Since Yukon Energy was established in 1987, rate matters related to Yukon Energy and ATCO Electric Yukon ("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 11 provides copies of the current OIC's directing the Board on rate determinations. The current OIC 1995/90 is provided, integrating OIC directives that have amended 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, recently changed to the Winter Electrical Affordability Rebate).

The following are major changes affecting firm rates and bills generally paid by Yukon Energy's customers since the 2023/24 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 Yukon Energy or AEY GRA. The current Rider F is 0.000 cents per kW.h and was last changed on April 1, 2025.

2. **Winter Electrical Affordability Rebate (formerly Interim Electrical Rebate)** – The Government of Yukon has recently provided an interim electrical rebate of 2.262 cents/kW.h 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. On April 1, 2025, the Government of Yukon replaced the Interim Electrical Rebate with the Winter Electrical Affordability Rebate. This new rebate is 3.377 cents/kW.h to a maximum of 1000 kW.h per month for the electricity consumed by non-government residential customers during the months of October through March. For electricity consumed by non-government residential the months of April through September, the rebate is 0.000 cents/kW.h.[24]

[24] https://yukon.ca/en/electrical-rebate#:~:text=Yukon%20residential%20electricity%20customers%20receive,agreement%20with%20Yukon%20Development%20Corporation.

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 (YIS).

Yukon Energy directly serves about 2,700 customers at the distribution (retail) level, most of whom live in and around Dawson City, Mayo and Faro, and other small communities in southern Yukon (Mendenhall, Aishihik, Champagne, Braeburn, Johnson’s Crossing, South Fox, Little Fox, Little Salmon, Drury Creek, Pine Lake, Canyon Creek, and McGundy).

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 AEY.

Actual firm sales to **non-industrial customers** (excluding secondary or interruptible customer load) supplied by Yukon Energy on the YIS in 2023 was 404.7 GWh, which was 3.0 GWh lower compared to the approved forecast load of 407.7 GWh. The preliminary actual firm sales to non-industrial customers in 2024 was 433.5 GWh, about 8.2 GWh higher than the approved load forecast and an increase of 28.8 GWh over 2023 actuals primarily due to higher wholesales. The forecast non-industrial firm sales in 2025 is 433.0 GWh, which is a decrease of 0.5 GWh over 2024 preliminary actuals primarily due to lower general service (reflecting lower Minto mine care and maintenance sales) offset by higher wholesale sales. The forecast non-industrial firm sales for the 2026 test year is 441.9 GWh, an increase of 8.9 GWh over 2025 forecast, and forecast for 2027 at 451.1 GWh or increase of 9.2 GWh over 2026 forecast.

Industrial sales under Primary Industrial Rate Schedule 39 includes sales to Victoria Gold Corporation Group's[1] Eagle Gold (Victoria Gold or "VG") and Hecla Yukon (previously Alexco Resources).[2] The actual industrial sales for 2023 were 74.5 GWh compared to forecast sales of 75.0 GWh. The preliminary actual industrial sales in 2024 were 46.1 GWh, 23.2 GWh lower than the approved forecast of 69.4 GWh due to lower sales to VG.[3] The forecast sales for the 2025-2027 test years at 42.8 GWh reflect a decrease of 3.3 GWh from 2024 actuals due to lower sales to VG.

Overall, the **total firm generation load** to be supplied by Yukon Energy on the YIS was forecast at 525.5 for 2023 and 538.2 GWh for 2024 in the 2023/24 GRA Compliance Filing. The actual total firm generation load was 520.6 GWh in 2023 and the preliminary actual firm generation load for 2024 was 521.3 GWh reflecting lower sales compared to the forecasts. The forecast total firm generation load for the 2025 test year is 517.7 GWh, about 0.7% lower than 2024 preliminary actuals, for the 2026 test year is 527.4 GWh, about a 1.9% increase over 2025 forecast, and for the 2027 test year is 537.3 GWh, about a 1.9% increase over 2026 forecast.

Non-firm secondary sales for 2023 and 2024 test years in the 2023/24 GRA were forecast at 2.9 GWh/year. The actual secondary sales in 2023 were 2.2 GWh and preliminary actual secondary sales for 2024 were 3.7 GWh. For the 2025-2027 test years, the secondary sales forecast is 2.9 GWh for each test year, at the same level as in the 2023/24 GRA and the average of 2023 and 2024 actual secondary sales.

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 2025-27 GRA test years, hydro and thermal generation forecasts are based on LTA water supply for hydro generation.

- The 2023/24 GRA Compliance Filing, based on annual LTA hydro generation capability, forecast that about 84.9% and 83.3% of grid generation requirements in 2023 and 2024, accordingly, would

[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.
[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 took over care and maintenance of the mine site as the mine ceased its mining operations. 2023 actual sales included sales to Minto Mine as an industrial customer for January-May 2023. After May 2023, the sales to Minto reflect the load for care and maintenance under the general service class.
[3] Due to heap leach failure on June 24, 2024 and damage to the power line connecting VG to the grid due to wildfires there were no sales to VG between June 24, 2024 and September 13, 2024. The grid power deliveries to VG were resumed in September 2024, however, lower than the previous consumption levels as remediation work continued at the mine site. In August 2024, based on the Yukon Government's request, a receivership was appointed by the court to oversee the remediation of the heap leach failure and its environmental impacts.

be met with hydro generation and about 14.8% and 14.0% with thermal generation, the remaining 0.4% and 2.7% from Independent Power Production (IPP).

- In 2023, hydro generation at LTA based on actual grid loads was calculated at 85.5% of grid generation, IPPs were 0.4%, and related thermal generation accounted for about 14.1%. Actual hydro generation in 2023 was 90.7% of grid generation, reflecting higher than LTA water availability.

- In 2024, hydro generation at LTA based on actual grid loads was calculated at 85.6% of grid generation, IPP at 1.7% and related thermal generation accounted for about 12.2%. The preliminary actual hydro generation in 2024 was 80.6% of grid generation, IPP at 1.7% while thermal generation was 12.7% of total generation reflecting issues at hydro plants and lower than LTA water availability.[4]

- The forecast firm generation forecast of 517.7 GWh in 2025, 527.4 GWh in 2026 and 537.3 GWh in 2027, results in forecast hydro generation at LTA supply accounting for 84.2% of grid generation in 2025, 83.2% in 2026 and 82.1% in 2027, and related forecast thermal generation accounting for 12.3% of grid generation in 2025, 13.4% in 2026 and 14.6% in 2027. IPP renewable generation at LTA is forecast at 3.4% of forecast grid generation in 2025, 3.4% in 2026 and 3.3% in 2027.

Winter peak generation on the YIS (including industrial load) in 2023 and 2024 was lower than the approved 2023/24 GRA forecasts, with the 2023 actual peak at 102.7 MW with the minimum temperature dropping to -31.6°C in Whitehorse (versus 119.5 MW forecast) and the 2024 actual peak reaching 111.6 MW with the minimum temperature dropping to -37.1°C in Whitehorse (versus 123.2 MW forecast). Forecast YIS peak load for the test years is 127.4 MW for 2025, 132.2 MW for 2026 and 136.2 MW for 2027.

Excluding industrial load, the forecast peak load in this Application is 121.9 MW in 2025 (based on winter 2025/26), 126.7 MW in 2026 and 130.7 MW in 2027. Based on existing dependable generation capacity available during winter on the YIS and the approved N-1 single contingency capacity planning criteria, a dependable capacity shortfall without rented diesel units is forecast at 32 MW for 2025, 31 MW for 2026 and 35 MW for 2027 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. Section 2.4 provides further details.

[4] Hydro generation was also impacted by issues in hydro generation plants, including ice issues in Aishihik hydro plant intake and issues with Mayo hydro plant intake. The recent outages of Aishihik hydro generating station unit #1 did not impact the overall hydro generation at Aishihik plant due to low water conditions.

2.2 SALES FORECAST

Yukon Energy's actual energy sales for 2023 and 2024, and forecast sales for 2025, 2026 and 2027 are detailed in Table 2.1 at the end of Tab 2.

Total forecast firm sales are 475.8 GWh for the 2025 test year, 484.7 GWh for the 2026 test year and 493.8 GWh for the 2027 test year. Total forecast firm sales include 373.7 GWh (2025), 381.9 GWh (2026) and 390.4 GWh (2027) of primary firm wholesale sales, 42.8 GWh (for each 2025, 2026 and 2027) of primary major industrial sales, and 59.3 GWh (2025), 59.9 GWh (2026) and 60.6 GWh (2027) 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 (79.5-80.0% of 2025-2027 firm sales forecasts).

Actual firm wholesales in 2023 were 347.7 GWh compared to the forecast of 351.3 GWh, and preliminary actual wholesales of 374.8 GWh in 2024 compared to the forecast sales of 362.4 GWh in the 2023/24 GRA. Higher than forecast wholesales in 2024 were primarily due to colder-than-normal weather, specifically in January of 2024.

Board Order 2022-03 directed that Yukon Energy in future GRA submissions provide details on discussions with AEY to align their wholesale sales forecasts. In Board Order 2024-05, the YUB noted that it finds the bottom-up approach as taken by AEY for sales forecasts is superior to the method employed by Yukon Energy as it takes into account future changes as incorporated through the consultation process that AEY undertakes. In preparation for the 2025-27 GRA, Yukon Energy obtained wholesale power purchase forecasts for the 2025-2027 years from AEY. These forecasts were then reviewed by Yukon Energy and found to be reasonable considering the preliminary actual sales for 2024, the population growth projections for the City of Whitehorse and AEY's evidence in the AEY's 2023/24 GRA regarding the expected connection of seven large general service customers by late 2024.

Accordingly, for the 2025, 2026 and 2027 test years, Yukon Energy used the forecast provided by AEY. Firm wholesales for 2025 are forecast in Table 2.1 at 373.7 GWh, which is 1.2 GWh (or 0.3%) lower than 2024 preliminary actual, and 25.9 GWh (or 7.5%) higher than 2023 actuals as 2024 was impacted by colder than normal weather conditions. Firm wholesales for 2026 are forecast at 381.9 GWh which is 8.3 GWh (or 2.2%) higher than the 2025 forecast; firm wholesales for 2027 are forecast at 390.4 GWh which is 8.5 GWh (or 2.2%) higher than the 2026 forecast.

2.2.2 Major Industrial

Victoria Gold and Hecla Yukon continue to be forecast as Major Industrial Customers during the test years. The 2023 actual sales were at 74.5 GWh compared to the forecast of 75.0 GWh in the 2023/24 GRA, and the preliminary actuals for 2024 were 46.1 GWh compared to the forecast of 69.4 GWh in the 2023/24 GRA. The forecast sales for each 2025, 2026 and 2027 test years at 42.8 GWh reflects a decrease of 3.3 GWh from 2024 preliminary actuals.

- The Minto Mine sales are included under the industrial customer class for January-May 2023 with about 16.3 GWh. The sales after May 2023 are for care and maintenance and are included under the General Service class.[5]

- Victoria Gold actual load in 2023 of 42.7 GWh was 0.9 GWh lower compared to the approved forecast load of 43.6 GWh. The preliminary actual load for 2024 of 23.3 GWh was 24.3 GWh lower compared to the approved forecast load of 47.6 GWh. Due to the heap leach failure on June 24, 2024, power consumption was dramatically reduced and the power line was de-energized on June 26, 2024 due to damage caused by wildfires. Therefore, there were no sales to VG between June 26, 2024 and September 13, 2024. When grid power deliveries to VG resumed in September 2024, it was at lower than the previous consumption levels as remediation work continued at the mine site. In August 2024, based on the Yukon government's request, a receivership was appointed by the court to oversee the remediation of the heap leach failure and its environmental impacts.[6] Based on discussions with the receiver and Yukon government, there are still uncertainties regarding the future loads and for how long the remediation will continue. Yukon Government notes that "on December 9, the court approved amendments to the Receivership order for Victoria Gold Corp. to allow the next phase of remediation work at the Eagle Gold Mine." For the purpose of this GRA, 21.0 GWh/year sales forecast for each 2025, 2026 and 2027 test years.[7]

- The 2023 actual sales to Hecla Yukon were 15.5 GWh which is 0.4 GWh higher compared to the approved forecast of 15.1 GWh; the 2024 preliminary actual sales were 22.8 GWh which is 1.0

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[5] 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 to ensure environmental protection is maintained at the Minto Mine.

[6] Yukon government noted that it was not the government's intention to shut down Victoria Gold when it put the mining company into receivership, and the goal won't be to close the Eagle gold mine or sell off Victoria Gold's assets, but rather to get the mine back to the state it was in before the failure. As reported by CBC on August 16, 2024 https://www.cbc.ca/news/canada/north/victoria-gold-update-august-16-1.7296458#:~:text=The%20Yukon's%20justice%20minister%20says,the%20company%20out%20of%20business.

[7] The VG Receiver was unable to provide the load forecast citing uncertainties around the remediation work, however, it highlighted expected added loads for new water plant equipment. The December 2024 actual sales were at around 1.2 GWh, however, the mine load was curtailed in December 2024 to address generation capacity limitations due to Mayo hydro plant issues and issues with the transmission equipment. Therefore, the forecast for the 2025-2027 years assume around 1.7 GWh/month sales.

GWh higher compared to the approved forecast of 21.8 GWh. Based on the information provided by Hecla Yukon, the near-term loads remain within the 2024 approved level; accordingly the forecast for each 2025, 2026 and 2027 test years is 21.8 GWh.

The GRA forecast 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.

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, most of whom live in and around Dawson City, Mayo and Faro, and other small communities in southern Yukon (Mendenhall, Aishihik, Champagne, Braeburn, Johnson's Crossing, South Fox, Little Fox, Little Salmon, Drury Creek, Pine Lake, Canyon Creek, and McGundy).

Retail sales are forecast at 59.3 GWh for the 2025 test year, 59.9 GWh for the 2026 test year and 60.6 GWh for the 2027 test year compared to actual sales of 57.0 GWh in 2023 and preliminary actual sales of 58.7 GWh in 2024. The lower sales in 2024, and forecasts for 2025-2027 compared to the 2023 actuals, mostly reflect the reduction in sales to Minto Mine related care and maintenance load (as discussed below).

2.2.3.1 Residential Sales

Actual firm residential retail sales were 17.3 GWh in 2023 compared to forecast sales of 17.7 GWh, and the preliminary actual sales for 2024 at 18.9 GWh compared to forecast sales of 18.1 GWh in the 2023/24 GRA. The forecast for 2025 is 19.4 GWh or a 2.0% increase from 2024 preliminary actuals, the forecast sales for 2026 are 19.7 GWh or a 2.0% increase from 2025 forecast, and the forecast sales for 2027 are 20.2 GWh or a 2.0% increase from 2026 forecast. The forecast growth in 2025, 2026 and 2027 is consistent with the population growth projections by the Yukon Government.[8]

[8] Yukon Bureau of Statistics population growth projection for 2025-2027 at around 2%.

2.2.3.2 General Service Sales

Actual firm general service retail sales were 39.5 GWh in 2023 compared to forecast sales of 38.6 GWh, and the preliminary actual sales for 2024 at 39.5 GWh compared to forecast sales of 44.7 GWh in the 2023/24 GRA. The forecast for 2025 is 39.8 GWh (a 0.7% increase from 2024 preliminary actuals), the forecast sales for 2026 is 40.0 GWh (a 0.7% increase from 2025 forecast) and the forecast sales for 2027 is 40.3 GWh (a 0.7% increase from 2026 forecast). General Service sales forecasts are based on less than half of the growth rate used for the residential class considering the recent growth in commercial sales being lower than the growth rate for the residential class.[9]

Two large General Service customers account for more than 37% of the firm General Service forecast retail sales for the test years:

- Actual sales to the Faro Mine remediation project were 9.0 GWh in 2023 and 7.8 GWh in 2024. The forecasts for the 2025-2027 test years are 7.8 GWh based on actual sales for 2024.

- Minto Mine care and maintenance load is included under the General Service class after May 2023. Actual sales for 2023 were at 9.3 GWh and 2024 at 5.5 GWh. There are uncertainties regarding the load for the reclamation work.[10] The forecasts for the 2025-2027 test years are 5.5 GWh based on actual sales for 2024.

2.2.3.3 Lighting (Street Lights and Space Lights)

Actual firm retail sales for lighting were 0.176 GWh in 2023 and preliminary actuals sales for 2024 were 0.182 GWh. The forecast for the 2025-2027 test years of 0.181 GWh was based on 2024 preliminary actuals.

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[9] For example, AEY's commercial sales growth between 2016 and 2023 was at 1% compared to 3.1% growth in residential sales and for the last five years, AEY residential sales growth was 2.3% compared to only 0.1% commercial sales growth.

[10] In September 2024, the Yukon government's statement noted that "reclamation and closure efforts at the Minto Mine site reached a milestone, surpassing the target of having one million cubic metres of water storage capacity available at the site. Adequate water storage capacity allows us to be able to respond safely to unforeseen weather events and ensure ongoing environmental protection". The statement also noted that the government "continue to engage with the court-appointed Receiver on the sales process for the mine. Regardless of the outcome of this process, work on reclaiming the site will move ahead. Our focus as a mine regulator is on protecting the environment and we remain committed to reclaiming and closing the site." https://yukon.ca/en/news/statement-minister-energy-mines-and-resources-streicker-milestone-abandoned-minto-mine-site#:~:text=%E2%80%9CWe%20continue%20to%20engage%20with,reclaiming%20and%20closing%20the%20site.%E2%80%9D.

2.2.4 Secondary Sales

The actual secondary sales in 2023 were at 2.2 GWh compared to forecast sales of 2.9 GWh, and the preliminary actual sales for 2024 are 3.7 GWh compared to forecast sales of 2.9 GWh. For the 2025-27 test years, the secondary sales forecast is at 2.9 GWh for each test year which is the same as approved in the 2023/24 GRA and also equal to the average of 2023 and 2024 actual sales.

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 Yukon Energy from 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 Yukon Energy grid load level as the variance between metered generation and sales. The 2023/24 GRA approved forecast losses were 8.8%. Actual losses were 8.7% in 2023 and preliminary actual losses in 2024 were also at 8.7%. The losses are forecast at 8.8% for the 2025-2027 test years which is the same as the approved losses in 2023/24 GRA and at the level of average for 2022-2024 actuals at 8.8% [2022 at 9.0%, 2023 and 2024 at 8.7%].

2.3.1 Integrated Grid Hydro Generation

The YIS has 95.2 MW of installed YEC hydro generation, of which approximately 68.5 MW can be relied upon for the winter peak as dependable capacity.

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 LTA. For the purpose of the 2025-27 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 shown in Table 2.2, LTA YEC hydro generation for 2023 was 446.7 GWh for the actual firm generation load of 522.6 GWh compared to the 2023 GRA forecast LTA hydro at 445.9 GWh for the forecast generation load of 525.5 GWh; LTA YEC hydro generation for 2024 was 446.3 GWh for the actual firm generation load of 521.3 GWh compared to the 2024 GRA forecast LTA hydro at 448.6 GWh for the forecast generation load of 538.2 GWh. The proposed forecast LTA YEC hydro generation for 2025 is 436.1 GWh, for 2026 is 438.7 GWh, and for 2027 is 441.2 GWh.[11]

Table 2.2 also shows actual (as opposed to LTA) hydro generation for 2023 and 2024, and forecast hydro generation for 2025, 2026 and 2027 based on available information. Actual hydro generation for 2023 indicates the extent to which favourable water conditions resulted in actual hydro generation higher than LTA [474.4 GWh vs 446.7 GWh LTA], while the preliminary actuals for 2024 at 423.5 GWh (compared to 446.3 GWh LTA) primarily reflects issues at hydro plants and lower water conditions experienced in Aishihik Lake. The forecast hydro generation for 2025 continues to reflect the impact of low water conditions with actual hydro generation expected to be lower than the LTA, while for the 2026 and 2027 forecast years Yukon Energy expects the water conditions to normalize with actual hydro generation expected to be higher than the LTA for both 2026 and 2027.

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:

- **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

[11] The LTA hydro and thermal generation numbers are calculated based on table provided in Appendix 2.1.

on thermal generation to meet base load energy requirements in winter and early spring when the peak is high and/or hydro water flows are constrained.

- **Drought-Flood Year Constraints** – In addition to seasonal supply constraints, systems predominantly based on hydro generation resources such as the Yukon grid are vulnerable to drought (low water) conditions. In these circumstances, hydro generation on the YIS must be supplemented by thermal generation.

2.3.2 IPP Purchases

The 2023 actual IPP purchases were at 1.9 GWh which is at the 2023 approved level, while the preliminary actual purchases for 2024 were at 8.8 GWh compared to the forecast of 14.3 GWh in the 2023/24 GRA. As summarized in Table 2.2, the electricity in the YIS is supplied by the LTA forecast IPP purchases of 17.7 GWh for each 2025-2027 test years.[12]

2.3.3 Diesel and LNG Thermal Generation

Yukon Energy's annual thermal generation costs for the 2025, 2026 and 2027 test years are based on the forecast total firm generation requirement less LTA hydro and IPP generation forecasts for the forecast firm generation load.

Table 2.2 shows LTA thermal generation for 2023 as approved at 77.6 GWh based on the forecast load of 523.5 GWh net of IPPs, versus LTA thermal generation of 73.9 GWh based on actual 2023 firm load of 520.6 GWh net of IPPs; LTA thermal generation for 2024 as approved at 75.3 GWh based on the forecast load of 523.9 GWh net of IPPs, versus LTA thermal generation of 66.2 GWh based on preliminary actual 2024 firm load of 512.5 GWh net of IPPs. Table 2.2 also shows actual (as opposed to LTA) diesel and LNG thermal generation for 2023, highlighting the extent to which favourable water conditions (and the related higher than LTA hydro generation) resulted in actual thermal generation at 46.7 GWh being below LTA thermal, while 2024 preliminary actual thermal generation of 92.9 GWh was higher than the LTA thermal reflecting lower hydro generation as discussed in Section 2.3.1 (lower water conditions experienced in Aishihik Lake combined with issues in the hydro generating stations).

[12] These IPP generation forecasts assume the currently connected seven IPPs, five solar IPPs and two wind IPPs. The IPP supply forecast is based on the LTA contract amounts signed with the IPPs. No other IPPs are expected to be connected to the grid during the test years.

The forecast 2025 LTA thermal generation is 63.9 GWh, for 2026 is 70.9 GWh and for 2027 is 78.4 GWh. The forecasts for the test years are based on the LTA hydro and thermal generation calculation table as provided in Appendix 2.1, reflecting the following:[13]

- Updated load curves reflecting changes to monthly sales related to non-industrial and industrial load shape;
- Loads to reflect expected IPPs for 2025-2027; and
- All remaining inputs are the same as in the 2023/24 GRA, including the number of water year records [41 water years], licence conditions and flow restrictions.

It is assumed in the Application that 80% of LTA thermal generation requirements as forecast for the test years will be met by LNG, with the balance (20%) supplied by diesel generation.

The Board in its Order 2024-05, Appendix A, paragraph 89 directed Yukon Energy "to demonstrate, at the time of its next GRA, that the blended thermal ratio proposed by YEC is the correct LTA blended fuel mix." Appendix 3.2 in Tab 3 addresses the Board directive regarding the fuel mix for the 2025-27 GRA.

In addition to the thermal generation forecast to supply required firm loads, Yukon Energy 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. Tab 3, Section 3.2 provides further details and forecasts of thermal fuel consumption for maintenance activities.

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[13] 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.

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 (including industrials) is forecast to be 127.4 MW in 2025 (winter 2025/26), 132.2 MW in 2026 and 136.2 MW in 2027.[14] The actual peak demand was 102.7 MW in 2023 and 111.6 MW in 2024. The non-industrial peak forecasts are based on Itron econometric model, which was used in the 2016 Resource Plan as well as the 10-Year Renewable Electricity Plan. 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 regarding 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°C design temperature (the coldest daily average temperature in Whitehorse in the last 10 years). In 2019, the long-term peak forecast design temperature was updated to -37°C based on the new record coldest day from January 2019. The current updated peak forecasts use -39°C based on the new coldest day record from January 2022. The same methodology that was employed in the 2023/24 GRA.

Yukon Energy continues to communicate with relevant stakeholders in order to ensure the load forecasts are based on currently available information. As noted in Sections 2.2.1 and 2.2.2, Yukon Energy 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 considers wide-range projections [i.e., other stakeholder inputs].

Dependable Capacity to meet Peak 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 criteria adopted

[14] 121.9 MW non-industrial and industrial peak at 5.5 MW forecast to occur in December 2025, 126.7 MW non-industrial and 5.5 MW industrial peak forecast to occur in December 2026, and 130.7 MW non-industrial and 5.5 MW industrial peak forecast to occur in December 2027. Non-industrial peak is forecast at -39 deg. C.

in the 2006 Resource Plan required that dependable winter capacity on each hydro grid be sufficient to meet both of the following requirements:

- **Loss of Load Expectation (LOLE)**[15] – 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.[16] 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.

- **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.[17]

In 2011, as part of the five-year update to the 2006 Resource Plan, Yukon Energy reviewed the capability of the new system (including the integration of WAF and MD grids, and the completion of Mayo B), focusing on the question of whether the 2 hours/year loss of load expectation planning target, measured using the existing software and modeling approach,[18] 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

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[15] The LOLE assessments in the 2006 Resource Plan included industrial load. However, the Board in its report to the Yukon government on the 2006 Resource Plan recommended that "to ensure that no new generating capacity is added for the purpose of ensuring reliable supply to major industrial customers and to ensure consistency with the N-1 criterion, major industrial loads should not be included in the LOLE calculation." Although the 2011 and 2016 updates to the resource plan also assumed industrial load in the LOLE, consistent with the initial assessments, to date, the LOLE criterion has not been the driving factor in the capacity shortfall calculations, therefore, the issue of inclusion or exclusion of the industrial load was never raised.

[16] 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.

[17] 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.

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

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.[19]

The 2016 Resource Plan and the subsequent GRAs (2017/18, 2021 and 2023/24) 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; this continues to be the case for the 2025-27 GRA).[20] Please see Tab 5, Appendix 5.4A which discusses Yukon Energy's plan to develop a permanent thermal capacity, Whitehorse Power Expansion Project, to enhance system reliability and reduce reliance on diesel rentals.

Maximum rated winter capacity for hydro and thermal units continues to be take into account reduced winter water availability at Whitehorse and Mayo (i.e., impact of restricted Mayo GS winter flows) as well as maximum generation output that each hydro and thermal resource can produce when load tested at ambient temperatures during the winter.

In its Order 2024-5 (Appendix A, paragraph 137), the Board directed Yukon Energy to provide "a strong industry based and accepted approach on what the manufacturers accept as criteria and evidence for uprating thermal generation units." Maximum rated winter capacity for thermal units continues to be the maximum generation output that each resource can produce when load tested at ambient temperatures during the winter – and uprates as such are not a specific separate issue going forward. However, starting in winter 2024/25 for this GRA, Yukon Energy has adopted a more conservative approach for determining the winter dependable capacity of its generation resources (i.e., the maximum generation output that a resource can reliably provide during a period of greatest demand in the winter), including both thermal and hydro generation resources, to calculate each resource's dependable capacity by multiplying its maximum rated winter capacity by its effective load carrying capacity (ELCC).

[19] 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.

[20] 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.

The ELCC, expressed as a percentage, is the capacity contribution that a resource provides in meeting the grid's reliability target; it reduces the resource's dependable capacity to reflect expected reliability problems or unplanned outage events when the resource would not be available for generation during peak periods.[21]

- **ELCC for Hydro Units** – The ELCC for Whitehorse and Aishihik hydro units is determined by applying a 96% effective capacity factor to the maximum rated winter capacity, based on a Loss of Load Expectation (LOLE) Study completed by Interlock Energy in 2024. An ELCC of 100% is assumed for Mayo hydro facilities because only two out of the four turbines are operated in the winter due lower water levels and downstream flow restrictions, and there is sufficient generation available in the event that a turbine is forced out.

- **ELCC for Thermal Units** – The ELCC of thermal units is determined by applying the Forced Outage Rate (FOR) percentage as a reduction to winter rated capacity.[22]

    - The FOR for each Yukon Energy owned thermal station is determined based on forced outage data for the past five years. This yields weighted average FORs of 12% for LNG units (which reflects WG1 and WG2 having higher FORs during 2020 to 2024 due to unplanned outages); 1% for permanent diesel units in Whitehorse and Faro; 3% for permanent diesel units in Mayo; and 4% for permanent diesel units in Dawson.

    - In the absence of data, a FOR of 4% is conservatively assumed for the FOR for all additional committed and planned Yukon Energy owned thermal units (e.g., thermal replacements in Whitehorse, Faro and Calliston).

    - A FOR of 10% is conservatively assumed for all AEY diesel units connected to the YIS.

    - For diesel rental units, a FOR of 15% has been assumed to reflect reliability experience with those units.

Before diesel rentals, the dependable capacity shortfall with respect to the forecast non-industrial winter peak based on the single contingency (N-1) criterion is forecast to be about 32 MW in 2025/26, 31 MW in 2026/27 and 35 MW in 2027/28, as outlined in the table below. To close the N-1 capacity shortfall, YEC is

[21] Consistent with North American Electric Reliability Corporation (NERC) standards, ELCC is an output of probabilistic Loss of Load Expectation (LOLE) modelling for individual resource facilities or types. Based on NERC standards, winter dependable capacity of dispatchable resources, such as thermal generation units, is a function of the unit's capacity and its Forced Outage Rate (FOR).
[22] For thermal generation units: Winter dependable capacity = (1 – FOR) x Maximum rated winter capacity, where the ELCC of the thermal unit is estimated as (1 – FOR).

planning to rent 22 diesel rental units for winter 2025/26, 2026/27 and 2027/28 based on the assumed multi-year rental agreement with the supplier.[23]

		2025/26	2026/27	2027/28
A	Non-industrial peak under N-1	120.6	125.4	129.4
B	Dependable capacity under N-1	88.6	94.2	94.4
C=B-A	Capacity shortfall under N-1	-31.9	-31.1	-35.0
D	Diesel rentals=22 units each unit at 1.53 MW	33.7	33.7	33.7
E=C+D	Capacity (Shortfall)/Surplus with diesel rentals	1.7	2.5	-1.4

Table 2.3 at the end of this Tab provides the YIS total or nameplate capacity, maximum rated winter capacity, and winter dependable capacity for each Yukon Energy owned hydro and thermal unit as well as for total AEY diesel units for the winter of 2027/28; BESS and DSM contributions to these capacities are also provided.

[23] Although, renting 22 diesel units [1.53 MW dependable capacity per unit based on 1.8 MW each unit and 15% FOR] results in a excess capacity of 1.7 MW in 2025/26 and 2.5 MW in 2026/27 [one extra unit in each winter], Yukon Energy is planning to rent 22 units under a multi-year contract in order to avoid a shortfall for the 2027/28 winter. Yukon Energy will work with the Yukon government to secure a mutual aid capacity in order to close the capacity shortfall of 1.4 MW for 2027/28 winter. The dependable capacity under N-1 in 2027/28 of 94.4 MW reflects (subject to rounding) total dependable capacity of 131.0 MW per the attached table less 35.5 MW for Aishihik hydro plant and 1.1 MW for AEY Haines Junction diesel as both would not be available when the transmission line is out of service. The increase of 5.6 MW in dependable capacity from 2025/26 to 2026/27 reflects the addition of BESS [5.5 MW] and incremental DSM [0.1 MW], and the increase of 0.15 MW in dependable capacity from 2026/27 to 2027/28 reflects incremental DSM (in summary, DSM is 0.25 MW in 2025, 0.35 MW in 2026, and 0.50 MW in 2027). The non-industrial peak numbers are net of Haines Junction peak of 1.3 MW which would not be supplied by the grid under N-1 conditions. The GRA assumes 10 rental units in Whitehorse, 7 units in Faro and 5 units in Mayo.

Table 2.1:
Summary of Customers, Energy Sales and Revenues

						GRA Forecast		
Line No.	**Description**	**2023 Approved**	**2024 Approved**	**2023 Actual**	**2024 Preliminary Actual**	**2025 Forecast**	**2026 Forecast**	**2027 Forecast**
1	**Residential**							
2	Customers	1,858	1,898	1,889	1,968	2,008	2,048	2,088
3	Sales in MWh	17,693	18,090	17,328	18,989	19,369	19,756	20,151
4	MWh sales per customer	9.5	9.5	9.2	9.6	9.6	9.6	9.6
5	Revenue ($000s)	2,532	2,611	2,472	2,749	2,823	2,879	2,937
6	Cents per KWh	14.3	14.4	14.3	14.5	14.6	14.6	14.6
7	**General Service**							
8	Customers	529	536	561	612	618	624	630
9	Sales in MWh	38,569	44,698	39,502	39,520	39,781	40,044	40,310
10	MWh sales per customer	72.9	83.4	70.5	64.6	64.3	64.1	64.0
11	Revenue ($000s)	6,272	7,175	6,476	6,860	6,496	6,539	6,583
12	Cents per KWh	16.3	16.1	16.4	17.4	16.3	16.3	16.3
13	**Industrial**							
14	Sales in MWh	75,045	69,368	74,498	46,127	42,796	42,796	42,796
15	Revenue ($000s)	9,772	8,809	9,586	6,888	5,724	5,628	5,628
16	Cents per KWh	13.0	12.7	12.9	14.9	13.4	13.2	13.2
17	**Street lights**							
18	Sales in MWh	168	168	168	172	171	171	171
19	Revenue ($000s)	82	82	83	83	83	83	83
20	Cents per KWh	48.9	48.9	49.4	48.3	48.6	48.6	48.6
21	**Space lights**							
22	Sales in MWh	9	9	9	10	10	10	10
23	Revenue ($000s)	2	2	3	3	3	3	3
24	Cents per KWh	27.3	27.3	29.2	26.5	26.9	26.9	26.9
25	**Total Company - Firm Retail & Ind.**							
26	Customers	2,387	2,434	2,450	2,580	2,626	2,672	2,718
27	Sales in MWh	131,484	132,333	131,504	104,818	102,127	102,777	103,439
28	Revenue ($000s)	18,660	18,679	18,619	16,582	15,128	15,132	15,234
29	Cents per KWh	14.2	14.1	14.2	15.8	14.8	14.7	14.7
30	**Wholesale sales**							
31	Sales in MWh	351,291	362,365	347,704	374,831	373,662	381,929	390,420
32	Revenue ($000s)	29,150	30,069	28,852	31,103	31,006	31,692	32,397
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3	8.3	8.3
34	**Total Company - Firm**							
35	Sales in MWh	482,775	494,699	479,208	479,649	475,788	484,706	493,858
36	Revenue ($000s)	47,810	48,748	47,471	47,685	46,135	46,824	47,631
37	Cents per KWh	9.9	9.9	9.9	9.9	9.7	9.7	9.6
38	**Secondary**							
39	Sales in MWh	2,931	2,931	2,214	3,699	2,931	2,931	2,931
40	Revenue ($000s)	358	358	227	379	287	287	287
41	Cents per KWh	12.2	12.2	10.2	10.2	9.8	9.8	9.8
42	**Total Company**							
43	Sales in MWh	**485,706**	**497,630**	**481,422**	**483,348**	**478,719**	**487,637**	**496,789**
44	Revenue ($000s)	**48,168**	**49,106**	**47,698**	**48,064**	**46,422**	**47,112**	**47,918**
45	Cents per KWh	**9.9**	**9.9**	**9.9**	**9.9**	**9.7**	**9.7**	**9.6**
46	Rider J ($000s) at the 2023/24 GRA	33,999	41,844	25,432	35,154	40,954	41,681	42,474
47	**Total Sales Revenues[1]**	**82,166**	**90,950**	**73,130**	**83,218**	**87,376**	**88,792**	**90,392**
48	**Total Sales Revenues excluding secondary sales**	**81,809**	**90,592**	**72,903**	**82,839**	**87,089**	**88,505**	**90,105**

Note:
1. Excludes revenues from other revenues.

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

Line No.	Description	2023 Approved	2024 Approved	2023 Actual	2024 Preliminary Actual	GRA Forecast 2025 Forecast	GRA Forecast 2026 Forecast	GRA Forecast 2027 Forecast
	Sales and Losses							
1	Total Energy Sales	485,706	497,630	481,422	483,348	478,719	487,637	496,789
2	Losses - MWh	42,938	43,791	41,659	41,926	42,127	42,912	43,717
3	Losses - %	8.8%	8.8%	8.7%	8.7%	8.8%	8.8%	8.8%
4	Total Generation	528,644	541,421	523,081	525,274	520,847	530,550	540,507
5	Secondary Sales Related	3,190	3,189	2,473	3,949	3,189	3,189	3,189
6	Firm Load Generation	525,454	538,232	520,608	521,325	517,658	527,360	537,318
	Actual Generation - MWh							
	Hydro Generation							
7	Whitehorse	280,502	261,359	250,264	247,159	262,395	272,530	269,727
8	Aishihik	134,299	132,847	153,022	110,772	76,848	69,509	70,754
9	Mayo	71,595	73,895	71,144	65,606	73,731	116,867	125,089
10	Total Hydro	486,395	468,101	474,430	423,537	412,974	458,905	465,570
11	**Wind Turbine**	0	0	0	0	0	0	0
12	**IPPs**	1,964	14,289	1,962	8,847	17,717	17,717	17,717
	Diesel Generation[1]							
13	Whitehorse	5,405	7,923	5,855	22,012	17,971	3,208	8,103
14	Faro	1,780	2,029	1,097	7,446	3,409	566	1,550
15	Dawson	987	1,669	3,108	6,679	184	24	76
16	Mayo	95	183	241	4,898	2,297	381	1,043
17	Total Diesel	8,267	11,804	10,300	41,036	23,861	4,179	10,772
18	**LNG Generation**[1]	32,017	47,228	36,389	51,854	66,295	49,749	46,448
19	**Total Thermal**[1]	40,285	59,031	46,689	92,890	90,156	53,927	57,220
	Source - %							
20	**Hydro Generation**	92.0%	86.5%	90.7%	80.6%	79.3%	86.5%	86.1%
21	**LNG Generation**	6.1%	8.7%	7.0%	9.9%	12.7%	9.4%	8.6%
22	**Diesel Generation**	1.6%	2.2%	2.0%	7.8%	4.6%	0.8%	2.0%
23	**IPP Generation**	0.0%	0.0%	0.0%	1.7%	3.4%	3.3%	3.3%
	LTA Generation - MWh							
24	**LTA Hydro Generation**	445,912	448,609	446,690	446,308	436,084	438,717	441,196
25	**LTA Wind Generation**	0	0	0	0	0	0	0
26	**IPP Generation**	1,964	14,289	1,962	8,847	17,717	17,717	17,717
27	**LTA Thermal Generation**	77,578	75,334	73,918	66,170	63,857	70,926	78,405
28	**Total LTA Generation**	525,454	538,232	522,570	521,325	517,658	527,360	537,318
	Peak - MW[2]							
29	**Integrated System**	119.5	123.2	102.7	111.6	127.4	132.2	136.2

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 forecast to occur in December (forecasts assume weather normalized temperature) and includes industrial peak.

1 **Table 2.3: Dependable Capacity for the Yukon Integrated System – Winter 2027/28**

Location	Unit #	Prime Mover Type	Total Capacity (kW)	Max. Rated Winter Capacity (kW)	Dependable Capacity (kW)
Aishihik					
Hydro	AH1	hydro	15,600	15,000	14,400
	AH2	hydro	15,600	15,000	14,400
	AH3	hydro	7,000	7,000	6,720
			38,200	**37,000**	**35,520**
Faro					
Diesel	FD7	diesel	3,000	3,000	2,970
	FD8	diesel	2,600	2,600	2,496
	FD9	diesel	2,600	2,600	2,496
			8,200	**8,200**	**7,962**
Dawson					
Diesel	DD1	diesel	800	800	768
	DD2	diesel	1,000	1,000	960
	DD3	diesel	1,030	1,030	989
	DD4	diesel	1,440	1,440	1,382
	DD5	diesel	1,500	1,500	1,440
	YM1	diesel	1,440	1,200	1,152
			7,210	**6,970**	**6,691**
Callison					
Diesel		diesel	3,250	3,250	3,120
		diesel	3,250	3,250	3,120
			6,500	**6,500**	**6,240**
Mayo					
Diesel	MD1	diesel	1,000	1,000	970
	MD2	diesel	1,000	1,000	970
	MD3	diesel	1,000	950	922
			3,000	**2,950**	**2,862**
Hydro	MH1	hydro	2,550	1,500	1,500
	MH2	hydro	2,550		
	MBH1	hydro	5,310	2,500	2,500
	MBH2	hydro	5,310	2,500	2,500
			15,720	**6,500**	**6,500**
Whitehorse					
Hydro	WH1	hydro	5,800	3,500	3,360
	WH2	hydro	5,800	4,138	3,972
	WH3	hydro	8,400		
	WH4	hydro	21,327	20,000	19,200
			41,327	**27,638**	**26,532**
Natural Gas	WG1	Natural Gas	4,400	4,400	3,872
	WG2	Natural Gas	4,400	4,400	3,872
	WG3	Natural Gas	4,400	4,400	3,872
			13,200	**13,200**	**11,616**
Diesel	WD4	diesel	2,500	2,500	2,475
	WD5	diesel	2,500	2,500	2,475
	WD6	diesel	2,500	2,500	2,475
	WD7	diesel	3,300	3,000	2,970
	WD8	diesel	2,600	2,600	2,496
	WD9	diesel	2,600	2,600	2,496
			16,000	**15,700**	**15,387**
BESS			5,500	5,500	5,500
AEY diesel		diesel	7,175	6,363	5,727
		Hydro	95,247	71,138	68,552
		Natural Gas	13,200	13,200	11,616
		Diesel	40,910	40,320	39,142
		Battery	5,500	5,500	5,500
		AEY diesel	7,175	6,363	5,727
		DSM	500	500	500
2		Total	162,532	137,021	131,037

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 2025-27 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 2025, 2026 and 2027 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 LTA thermal generations are 63.857 GWh for 2025, 70.926 GWh for 2026 and 78.405 GWh for 2027 based on Table 2.1-1 developed to determine annual expected YEC thermal generation based on long-term average YEC hydro generation at YEC forecast grid loads (net of IPPs and Fish Lake generation) ranging from 480 to 580 GW.h/year. The table is based on the same assumption as the 2023/24 GRA in regard to water records, i.e., 41 water year records, from 1981 to 2021, but with updated load curves reflecting changes to monthly sales related to non-industrial and industrial load shape and/or volumes, and expected IPP energy deliveries. One table was developed for all three test years considering no change in the IPP deliveries and similar load shape.

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

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	429.601	50.399			
2	485.0	431.406	53.594	5.0	3.195	64%
3	490.0	433.084	56.916	5.0	3.322	66%
4	495.0	434.651	60.349	5.0	3.433	69%
5	500.0	436.121	63.879	5.0	3.529	71%
6	505.0	437.510	67.490	5.0	3.611	72%
7	510.0	438.830	71.170	5.0	3.681	74%
8	515.0	440.092	74.908	5.0	3.738	75%
9	520.0	441.308	78.692	5.0	3.784	76%
10	525.0	442.488	82.512	5.0	3.820	76%
11	530.0	443.640	86.360	5.0	3.848	77%
12	535.0	444.773	90.227	5.0	3.867	77%
13	540.0	445.892	94.108	5.0	3.880	78%
14	545.0	447.005	97.995	5.0	3.888	78%
15	550.0	448.115	101.885	5.0	3.890	78%
16	555.0	449.222	105.778	5.0	3.893	78%
17	560.0	450.326	109.674	5.0	3.895	78%
18	565.0	451.428	113.572	5.0	3.898	78%
19	570.0	452.527	117.473	5.0	3.901	78%
20	575.0	453.624	121.376	5.0	3.903	78%
21	580.0	454.718	125.282	5.0	3.906	78%

Example
Expected YEC Thermal Generation for the total YEC generation at 499.941 GW.h (net of expected IPP & Fish Lake)

Step 1. Find the closest load from Column A that is less than 499.941 GW.h = 495 GW.h (Line 4).

Step 2. Find the thermal generation from Column C = 60.349 GW.h (Line 4).

Step 3. Find the difference between the given load (499.941 GW.h) and load from Step 1 (495 GW.h) = 4.941 GW.h

Step 4. Apply the percentage from Column F (Line 5, 71%) to the difference from Step 3 (4.941 GW.h) = 3.508 GW.h

Step 5. Add numbers from Step 2 (60.349 GW.h) and Step 4 (3.508 GW.h) = 63.857 GW.h

The expected thermal generation at 499.941 GW.h load [net of Fish Lake and IPPs] is 63.857 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 [same as 2023/24 GRA]).
5. The simulation model results are based on forecast loads and IPP deliveries for 2025-2027 years, and current installed capacity and licensing/permits and requires modifications when new mines/industrial loads or IPP generation are connected to [or disconnected from] the grid and to address material changes in hydro system capabilities, licensing/permits and other factors.
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:

- Overview;
- Components of Revenue Requirement; and
- Stabilization Mechanisms.

3.1 OVERVIEW

Tab 3 summarizes the revenue requirement for Yukon Energy for the 2025, 2026 and 2027 test years, as well as comparative figures for 2023 and 2024 actuals.

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

1. **Fuel and purchased power** which include fuel costs for generation as well as power purchase costs, including from Independent Power Producers (IPPs);
2. **Non-fuel operating and maintenance expenses** which include costs related to the production and delivery of energy and administrative costs of support functions;
3. **Depreciation and amortization** of property plant and equipment and deferred costs included in rate base; and
4. **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 2025, 2026 and 2027 revenue requirement to the YUB approved (compliance) revenue requirement for the 2023/24 GRA ("2023 approved" and "2024 approved"), as well as the 2023 and 2024 actuals.

Actual revenue requirement for 2024 was $89.2 million or 2.3% lower than the approved compliance filing costs of $91.3 million. The forecast revenue requirements proposed for 2025 in the Application is $107.4 million [$16.0 million or 17.6% higher than the 2024 approved revenue requirement], for 2026 is $122.4 million [a further increase of $15.0 million or 14.0% over 2025] and for 2027 is $134.9 million [a further increase of $12.4 million or 10.2% over 2026]. In general, Yukon Energy's forecast 2025, 2026 and 2027 revenue requirements primarily reflect proposed adjustments to thermal generation requirements and fuel prices, changes to labour and non-labour costs, and changes to depreciation and return on rate base resulting from the impact of increases in rate base relative to 2024 approved numbers.

Table 3.1:
Yukon Energy Revenue Requirement
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Fuel and Purchased Power	$ 16,128	$ 18,054	$ 14,736	$ 15,922	$ 20,237	$ 22,130	$ 24,131
Non-Fuel Operating and Maintenance	34,930	37,314	35,139	40,150	43,143	45,678	46,750
Depreciation and Amortization	12,811	14,703	12,902	15,137	20,261	24,190	26,398
Return on Rate Base	18,691	21,273	15,664	18,033	23,751	30,408	37,571
Revenue Requirement/Revenue	$ 82,561	$ 91,344	$ 78,440	$ 89,241	$ 107,392	$ 122,406	$ 134,850

Each of the above categories of 2025, 2026 and 2027 revenue requirement is reviewed in detail below.

3.2 FUEL AND PURCHASED POWER

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 cost for power purchased from other suppliers. Fuel and Purchased Power costs as set out in Table 3.2 for the 2025 test year is $20.2 million (increase from $18.1 million in 2024 approved), increases to $22.1 million in 2026, and to $24.1 million in 2027. The increases for the 2025, 2026 and 2027 test years reflect primarily higher fuel prices, as well as increased purchased power cost for IPPs.

Table 3.2:
Fuel and Purchased Power
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Fuel	$ 15,748	$ 15,295	$ 14,367	$ 14,214	$ 16,802	$ 18,661	$ 20,627
Purchased Power	380	2,759	368	1,707	3,435	3,469	3,504
Total Fuel and Purchased Power	$ 16,128	$ 18,054	$ 14,736	$ 15,922	$ 20,237	$ 22,130	$ 24,131

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

3.2.1 Fuel

Yukon Energy's annual fuel costs for GRA revenue requirements are based on forecast hydro and thermal generation determined on a long-term average basis (see Section 2.3). 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. Forecast long-term average thermal requirements for the test years are assumed to be supplied with a combination of 80% LNG and 20% diesel generation; this is different from the ratio approved in the 2024 GRA of 90% LNG and 10% diesel (see Appendix 3.3). As reviewed in Section 3.6, the Low Water Reserve Fund (LWRF) is assumed to address any variance between actual thermal generation and long-term average requirements caused by variations in water supply for hydro generation facilities after each fiscal year end, and Rider F is assumed to address any variance in diesel or LNG delivered fuel prices from the forecast prices assumed for the Application on a quarterly basis. The proposed test year fuel costs also include requirements for thermal facility fuel use for maintenance.

As reviewed in Section 2.3 and illustrated in Table 3.2.1, forecast long-term average thermal generation is 63.9 GW.h in 2025, 70.9 GW.h in 2026 and 78.4 GWh in 2027, as compared with 75.3 GW.h in 2024 approved. The fuel cost for forecast long-term average thermal generation is $16.8 million in 2025, $18.7 million in 2026 and $20.6 million in 2027 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; and diesel run-ups are required in any one month when the engines have not run. For maintenance activities, the forecast diesel is 0.021 GWh/year and LNG is 0.017 GWh/year for total cost of $0.011 million/year compared to $0.061 million in the 2023/24 GRA.

The total fuel cost change since 2024 Approved is $1.507 million in 2025, $3.366 million in 2026 and $5.332 million in 2027. As shown in Table 3.2.1, increased fuel prices are the major factor driving these increased fuel costs, with forecast long term average thermal generation in 2025 and 2026 lower than 2024 Approved, LNG price increasing 30% over 2024 Approved, diesel price increasing 4.9% over 2024 Approved, and the LNG/diesel fuel mix change increasing average forecast fuel price by about 2.9%.

Table 3.2.1:
Fuel Cost Comparison: 2023 and 2024 Approved, 2025-27 Proposed Forecast
($000)

	2023 Approved	2024 Approved	2025 With GRA	2026 With GRA	2027 With GRA
Load net of Fish Lake and IPPs (MW.h)	523,492	523,944	499,941	509,643	519,601
LTA Thermal Generation (MW.h)	77,578	75,334	63,857	70,926	78,405
LNG	69,820	67,801	51,086	56,741	62,724
Diesel	7,758	7,533	12,771	14,185	15,681
Fuel Prices, $/kW.h					
LNG Price	$0.1906	$0.1906	$0.2482	$0.2482	$0.2482
Weighted Average Diesel price	$0.3069	$0.3069	$0.3219	$0.3219	$0.3219
LTA Fuel Cost, $000	**$15,688**	**$15,234**	**$16,791**	**$18,650**	**$20,616**
Maintennace run-ups (MW.h)					
Diesel Run-Ups	198	198	21	21	21
LNG Run-Ups	-	-	17	17	17
Total Maintenance, $000	**$61**	**$61**	**$11**	**$11**	**$11**
Total Fuel Cost, $000	**$15,748**	**$15,295**	**$16,802**	**$18,661**	**$20,627**
Total fuel cost change from 2024 Approved, $000			$1,507	$3,366	$5,332
Fuel cost change due to LTA thermal volume			-$1,630	-$118	$1,481
Fuel cost change due to fuel price change			$3,137	$3,484	$3,851

Forecast LNG delivered price to Yukon Energy's Whitehorse thermal facility for the 2025 test year is $0.6403 per litre. This forecast for LNG cost reflects contracted liquefaction [$14.5/GJ] and shipping costs [$11.9/GJ] for 2025, as well as the current market price for commodity value [the actual price for December 22, 2024]. Yukon Energy forecasts average efficiency for LNG generation of 2.58 kWh/litre based on 2023/24 GRA approved efficiency [the average efficiency for the last three years at 2.55

kWh/litre]. The resulting forecast LNG cost is $0.2482/kWh as compared to the approved 2024 LNG price was $0.1906/kWh. Considering uncertainties around inflation, Yukon Energy used the same LNG cost for all three test years at $0.2482/kWh.

Direct negotiations with one LNG supplier were initiated because of the evolving LNG supply landscape, recognizing limited competition and supply constraints in the region. The LNG supply landscape has evolved significantly since Yukon Energy's last procurement in 2019. The following key developments shaped the new situation:

- **Market Consolidation**: Campus Energy, Ferus, and Cryopeak have merged into a single company. All three entities bid in Yukon Energy's last procurement, with Ferus (now Cryopeak) securing the contract.
- **Supply Contract**: Contract with Cryopeak was set to expire on November 30, 2024.
- **Potential New Suppliers**:
    - Cool LNG (Grand Prairie) and Linde (Fort Saskatchewan) are planning new LNG production facilities, but neither had begun construction as of late 2024.
    - Linde is planning to complete its Phase 1 plant in Q4 2025, which at 100% of their capacity would meet only about one-third of Yukon Energy's LNG demand.
    - Cool LNG is planning to begin production in Q1 2026.
- **Geographic Constraints**: Other LNG suppliers are based further south (towards Calgary, Alberta and Nelson, British Columbia), increasing logistical risks (trucking times, temperature loss) and transportation costs.

Due to the importance of securing fuel for generation, and as a result of procurement strategy discussions, a new LNG Supply Agreement was signed with Cryopeak Energy Solutions, effective December 1, 2024.

Forecast diesel delivered prices for the 2025, 2026 and 2027 test years are $1.1583 per litre for Whitehorse, $1.2313 per litre for Faro, $1.2685 per litre in Dawson and $1.2428 per litre in Mayo, and reflect the most recent diesel prices for Yukon Energy as of December 1, 2024. These diesel price forecasts are higher than the 2024 approved diesel prices reflecting increased market fuel prices. Yukon Energy forecast average efficiency for diesel fuel is 3.69 kWh/litre in Whitehorse, 3.48 kWh/litre in Faro, 3.78 kWh/litre in Dawson and 3.70 kWh/litre in Mayo based on 2023/24 GRA approved efficiencies. The overall grid efficiency is about 3.65 kWh/litre, the same as in the 2023/24 GRA. The average cost per kWh of diesel for the purposes of this Application is $0.3219/kWh compared to $0.3069/kWh in 2024 approved.

3.2.2 Purchased Power

Power purchased consists of power purchased from AEY and IPPs under the Yukon government's IPP Policy and OIC 2019/25 (see Tab 11 of this Application).

Purchased power costs from AEY include power purchased by Yukon Energy at Marsh Lake Control Structure and Johnson's Crossing. Forecast cost for purchases from AEY is $0.039 million in each test year compared to $0.051 million in 2024 Approved.

Purchased power from IPP’s is forecast at 17.7 GWh in each test year, compared to 14.3 GWh for 2024 Approved and 2.0 GWh for 2023 Approved (see Table 2.2). The purchase costs for the IPPs in 2025, 2026 and 2027 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].[1] Total IPP purchase power cost is forecast at $3.397 million for 2025, $3.431 million for 2026 and $3.465 million for 2027, compared to $2.708 million in 2024 Approved.

3.3 NON-FUEL OPERATING AND MAINTENANCE EXPENSES

The total non-fuel operating and maintenance expense approved in the 2024 GRA was $37.3 million. As illustrated in Table 3.3, the 2024 actual expenses exceeded approved at $40.2 million. Total operating and maintenance costs are forecast in the Application to increase to $43.1 million for 2025, $45.7 million for 2026 and $46.8 million for 2027.

[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”.

Non-fuel operating and maintenance expenses consist of labour and non-labour costs. Non-labour costs are further segregated into production, transmission, distribution, general O&M, administration, insurance and reserve for injuries/damages and property taxes. Table 3.3 reports labour expense as a company total; subsequently in this Tab, the labour expenses are broken out by function (see Sections 3.3.2 through 3.3.7).

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

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	$ 15,069	$ 16,132	$ 15,186	$ 17,058	$ 18,005	$ 19,530	$ 20,597
Production	7,797	9,491	7,650	9,931	9,779	9,975	10,174
Transmission	1,784	1,411	1,588	1,528	1,615	1,916	1,480
Distribution	276	426	393	645	426	435	443
General O&M	1,369	1,265	1,552	1,555	1,526	1,557	1,588
Administration	5,071	4,780	5,181	5,554	6,965	7,084	7,206
Insurance and Reserve for Injuries/Damages	2,805	3,033	2,834	3,120	4,056	4,392	4,455
Property Taxes	758	777	756	759	771	790	806
Total OM&A (Tab 7, Schedule 10)	$ 34,930	$ 37,314	$ 35,139	$ 40,150	$ 43,143	$ 45,678	$ 46,750

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 the YUB in Order 2018-10 para 133. An increase in labour expense makes up $4.466 million or 47% of the total $9.435 million increase in operating and maintenance expense forecast for 2027 over 2024 approved costs. The increase in labour expenses reflects both the increase in labour rates and number of positions as discussed below in Section 3.3.1.

Non-labour costs are forecast to increase by $3.955 million in 2025 over 2024 approved costs, an additional $1.010 million in 2026 and to increase by $0.004 million in 2027. The average annual compound increase in non-labour expenses is approximately 7% (2027 expenses over 2024 approved) with the largest increase resulting from Administration costs, approximately 49% of the total non-labour increase, as explained in Section 3.3.5.

Yukon Energy and the Yukon have experienced, and are expected to continue to experience, inflation in the test years. Inflation is assumed to reduce to historical levels of approximately 2%. As this is a three-year GRA, Yukon Energy has assumed future test year (2026 and 2027) costs would increase by 2%, if applicable. For example, where contracts exist, no additional future year adjustments for inflation has been made.

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 $18.0 million in 2025 as compared to 2024 approved costs of $16.1 million, increasing to $19.5 million in 2026, and $20.6 million in 2027.

Labour expense is generally a function of the following factors:

- **Labour Rates** – This includes factors such as base pay, benefit cost, and annual increments (performance increments, cost of living adjustments). This is heavily influenced by collective bargaining agreements (CBA). The current CBA expires December 31, 2025. Labour rates for 2025 are based on the current CBA. Negotiations for the CBA effective January 1, 2026 are expected to start in Q4 of 2025. Forecast 2026 and 2027 labour rates are estimated to reflect an inflationary increase of 2.00%. It is estimated that the new agreement will be finalized in late 2025 or early 2026.

- **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 2027 from 2024 approved [$4.466 million], approximately $3.071 million (69%) relates to additional headcount and the remaining $1.393 million (31%) 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 2025, 2026 and 2027 test years are net of vacancy factor adjustment of 9 FTEs for each test year, the same vacancy factor that was used for the 2023/24 GRA.

Table 3.4:
Employee Complement History

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
President & Corporate Services	3.10	3.10	3.34	3.29	3.10	3.10	4.10
Government Relations	1.00	2.00	1.00	-	-	-	-
Business Development	1.00	1.00	1.00	-	-	-	-
Communications & Customer Service	3.60	3.60	4.60	-	-	-	-
People & Culture	2.00	2.00	2.00	-	-	-	-
Partnerships & Business Services	-	-	-	15.05	15.25	16.50	18.00
Resource Planning, Environment, Health & Safety	10.60	11.13	11.10	11.98	12.60	14.85	14.85
Finance & Procurement	19.29	20.29	19.41	13.79	13.79	14.79	14.79
Operations	51.96	53.20	51.46	55.10	59.95	63.60	64.45
Engineering Services	20.50	23.50	19.75	24.25	24.25	27.00	28.25
Total FTE's	**113.05**	**119.81**	**113.66**	**123.46**	**128.94**	**139.84**	**144.44**
Vacancy	9.00	9.00	12.32	7.99	9.00	9.00	9.00
Total FTE's less Vacancy	104.05	110.81	101.34	115.47	119.94	130.84	135.44

Note:
1. The employee complement numbers are net of allocation to YDC.
2. In 2024, the positions under Government Relations, Business Development, Communications & Customer Service, People & Culture and IT were transferred to Partnerships & Business Services. Please see Table 3.4.1 for details.

Table 3.4 shows a forecast cumulative increase of total FTEs of 24.63 from 2024 approved to the 2027 test year. Table 3.4.1 further breaks down the changes.

Table 3.4.1:
Employee Complement Changes from Prior GRA

President & Corporate Services	
2024 GRA	3.10
Corporate Administrative Assistant-2027	1.00
2027 GRA	**4.10**
Government Relations	
2024 GRA	2.00
Positions transferred to Partnerships & Business Services-2024	(2.00)
2027 GRA	**-**
Business Development	
2024 GRA	1.00
Position transferred to Partnerships & Business Services-2024	(1.00)
2027 GRA	**-**
Communications	
2024 GRA	1.00
Position transferred to Partnerships & Business Services-2024	(1.00)
2027 GRA	**-**
Customer Service	
2024 GRA	2.60
Positions transferred to Partnerships & Business Services-2024	(2.60)
2027 GRA	**-**
People & Culture	
2024 GRA	2.00
Positions transferred to Partnerships & Business Services-2024	(2.00)
2027 GRA	**-**
Partnerships & Business Services	
2024 GRA	-
Positions transferred to Partnerships & Business Services-2024	13.10
Warehouse Worker changed to Digital Business Analyst-2024	1.00
Moved casual IT Help Desk to full-time IT Help Technician-2024	0.50
Increase to Field Service Representative-2025	0.40
New full-time position- People & Culture Generalist-2026	1.00
New full-time position- Infrastructure Coordinator-2026	1.00
New full-time position- Director Business Services-2027	1.00
2027 GRA	**18.00**
Finance, Procurement & Information Technology	
2024 GRA	20.29
IT positions transferred to Partnership & Business Services-2024	(4.50)
Warehouse Worker changed to Digital Business Analyst-2024	(1.00)
Procurement Specialist positions transferred to Ops. As Supervis	(1.00)
New full-time position, Manager, Warehousing- 2026	1.00
2027 GRA	**14.79**

Planning, Environment, Health & Safety	
2024 GRA	11.13
DSM Engineer & Project Manager term extensions-2024	0.47
Summer Student-Premier Scholarship moved from Engineering-2025	0.25
New full-time position, Resource Planner-2025	1.00
New full-time position, Training Coordinator-2025	1.00
New full-time position, Permitting and Monitoring Coordinator-2026	1.00
2027 GRA	**14.85**
Operations	
2024 GRA	53.20
Supervisor, Job Planning transferred FTE from Procurement-2024	1.00
Distribution Coordinator position transferred to Engineering-2024	(1.00)
Increase FTE for Casual/Temp Powerline Technician-2024	0.25
New full-time position, Maintenance Engineer- Electrical-2025	1.00
New full-time position, Maintenance Engineer- Mechanical-2025	1.00
New full-time position, Electrical Technologist-2025	1.00
New full-time position, OT Network and Automation Specialist-2025	1.00
New full-time position, SCC Operator and Coach	1.00
New full-time position, Financial Analyst-Operations-2025	1.00
Increase to Casual Plant Operators-2025	1.00
New full-time position, Apprentice PLT-2026	1.00
Increase to Community Part-Time Plant Operators-2026	1.00
New full-time position, Job Planner- Electrical-2027	1.00
New full-time position, EAM IT Systems Support-2027	1.00
2027 GRA	**64.45**
Engineering	
2024 GRA	23.50
Distribution Coordinator transferred from Operations-2024	1.00
Summer Student-Premier Scholarship moved to Planning-2025	(0.25)
New full-time position, Electrical Engineer-2026	1.00
New full-time position, Junior Draftsperson-2026	1.00
New full-time position, Project Coordinator-2026	1.00
New full-time position, T&D EIT-2027	1.00
2027 GRA	**28.25**

Total 2027 GRA	**144.44**
Total 2024 GRA	119.81
Total Difference	24.63

At historic staff levels, 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.

There are several corporate factors that directly affect employee complement:

- Focus on safe work practices;

- Increasing assets;
- Investment in people and technology;
- Steady growth in customer accounts;
- Increased planning requirements; and
- Continuing high capital demands to maintain existing aging assets.

To combat the above issues, Yukon Energy is forecasting an increased employee complement. A detailed description of the employee complement increases from 2024 approved to the forecast for 2027 is provided in Appendix 3.2. The largest increase in employee complement is in Operations, reflecting Yukon Energy's updated strategic objectives that focus on safety and reliability. The feedback received from employee surveys and other methods has shown the Operations department is tasked with more work than can be done at historical staffing levels. There has been a high level of overtime, high turnover and decreased morale. Population growth and increasing adoption of electrification has increased the workload and operational complexity of the operations department while aging infrastructure and the transition towards renewable energy sources requires more frequent maintenance, monitoring, and technical expertise. Increased staff is required in the Operations department to ensure capacity for equipment maintenance, emergency response, continuous improvement and to support future development projects.

Yukon Energy has made a conscious effort to limit increases only to those areas where required. Increased employee complement is due to an effort, where possible, to do more work internally as opposed to hiring outside consultants and contractors. An example of previously approved positions reducing consultant cost is the addition of the Manager, Regulatory in 2022. Preparation and drafting of this GRA application has been performed completely by the Manager, Regulatory (with assistance from other Yukon Energy staff). The consultant will be used for review and document finalization purposes, and as considered necessary during the remaining process. Previously, the consultant led the engagement from initial planning to project completion.

In addition to the factors affecting labour listed above, the capital/maintenance forecast allocation also impacts the forecast labour expenses. Yukon Energy 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 2024 approved revenue requirement forecasts included an allocation set at 17.9% capital and 82.1% maintenance. The 2024 actual results were 19.2% capital and 80.8% maintenance. For the 2025 test year the forecast allocation is 21.1% capital and 78.9% maintenance, for the 2026 test year the forecast allocation is 21.7% capital and 78.3% maintenance, and for the 2027 test year the forecast allocation is 21.7% capital and 78.3% maintenance. The ratio is based on Yukon Energy'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 2024 approved total production costs were $15.5 million. Total production cost in 2025 is forecast at $17.4 million, an increase of $1.9 million over 2024 approved. Total production cost is forecast to increase by $0.753 million in 2026 and further increase by $0.585 million in 2027.

Table 3.5:
Production Costs
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	$ 5,686	$ 6,040	$ 5,939	$ 6,669	$ 7,517	$ 8,071	$ 8,453
Diesel	5,639	7,343	5,698	7,783	7,642	7,794	7,950
LNG	382	407	275	467	389	396	404
Hydro	1,345	1,311	1,263	1,273	1,323	1,349	1,376
Energy Storage	0	0	0	0	13	13	14
Operation Supervision	430	430	414	409	554	566	577
Total Production	$ 13,483	$ 15,531	$ 13,590	$ 16,600	$ 17,437	$ 18,190	$ 18,775

Approximately 77% of the forecast increase in 2025 over 2024 approved for production costs is due to higher labour cost [$1.477 million increase in 2025 forecast over 2024 approved]. Approximately 74% of the forecast increase in 2027 over 2024 approved for production costs is due to higher labour cost [$2.413 million increase in 2027 forecast over 2024 approved].

Non-labour production expenses are forecast to increase by $0.430 million in 2025 over 2024 approved, with a further increase of $0.199 million in 2026, and a further increase of $0.202 million in 2027. The average annual compound increase in non-labour production expenses is approximately 3% (2027 expenses over 2024 approved). About $0.608 million or 73% of the total $0.831 million increases in non-labour expenses forecast in 2027 over 2024 approved are due to diesel generation related expenses, almost entirely accounted for by increased diesel rental costs.

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 2023/24 GRA approved forecast for 1.8 MW diesel rental units was 20 units (excluding spares); Yukon Energy rented 22 units for risk management (reliability) purposes. The forecast for the winters of 2025/26, 2026/27 and 2027/28 is 22 units (see Section 2.4 of Tab 2).

Diesel rental costs are forecast at $6.987 million in 2025, an increase of $0.226 million from 2024 approved. Forecast mobile diesel costs are based on negotiated contracts (the current diesel rental contract expires April 2025) and future rental costs (after contract expiry in April 2025) are expected to increase by an inflationary factor of 2% to $7.095 million in 2026 and $7.233 million in 2027. Overall, total diesel rental costs are increasing at an average annual compounded rate of only 2.28% due to savings resulting from contract negotiations that saw a decrease in transportation and commissioning charges.

Based on current information, the forecast diesel rentals as summarized above remain the only feasible option in 2025, 2026 and 2027 to ensure sufficient dependable capacity to meet the N-1 dependable capacity requirement during those test years. Appendix 3.1 provides a business case assessment for diesel rentals. In addition to the business case assessment, Yukon Energy looked at various alternatives to reduce reliance on diesel rentals for the 2025 to 2027 test years. These included:

- **Use of thermal generation at Eagle Gold site** – Yukon Energy approached the Receiver for Victoria Gold and enquired about the possibility of purchasing generation from Victoria Gold. The Receiver, after consultation with the site team, informed Yukon Energy that given the current pressures with the emergency remediation works on site, there is no capacity to sell back electricity from the generators to the grid.

- **Use of thermal generation at Minto Mine site** – Yukon Energy approached Selkirk First Nation (SFN) and enquired about the possibility of purchasing generation from Minto Mine. SFN was very interested. SFN allowed Yukon Energy representatives access to the site to inspect the condition of the three diesel generators located at Minto Mine. Unfortunately, the inspection showed that all three of the generators would require significant investment to make any of them capable of providing reliable electricity back to the grid. As a result of the cost and time required to perform the fixes, Yukon Energy did not pursue this option for the 2024/25 winter season.

- **Use of propane as thermal generation fuel** – Yukon Energy had discussions with two propane suppliers about the possibility of adding propane engines and the supply of propane. One supplier provided two quotes. However, both quotes resulted in substantially higher costs than diesel rentals (approximately double).

- **Mutual aid** – Yukon Energy has been working with the Government of Yukon, AEY and the City of Whitehorse to improve and test the inter-agency emergency protocols in case of power supply challenges in the territory. In September and October of 2024, all parties came together to develop and test the emergency protocols and successfully completed a drill on October 21, 2024. The drill simulated a transmission line failure and mutual-aid response. This included testing a key component of the protocol, which is shifting large buildings onto backup diesel generation to reduce the load on the electrical system and keep power flowing to Yukoners. During the drill, the Canada Games Centre and Whistle Bend Place successfully switched off their main electrical power supply and onto diesel generator backup, without disruption to services. This allowed the utilities to measure the impact of the emergency protocol and for all parties to test and evaluate their roles in a controlled setting. At the time of the exercise, the total system load was around 68 MW. Switching the Canada Games Centre and Whistle Bend Place to backup power saved approximately 1 MW of electricity. The drill highlights the importance of backup diesel generation in the Yukon, especially during the winter.

- **Public education** – Yukon Energy continues to educate Yukoners on ways they can reduce their electricity use, particularly in the winter months. This has included regular posts on Yukon Energy's Facebook page and information on the Yukon Energy website. Yukon Energy has also been promoting its Peak Smart program, as well as demand-shifting practices such as using the delay start function on appliances or using a block heater timer for vehicles, through social media, traditional media and in-person events.

- **Purchase of generators and related equipment** – During 2024, Yukon Energy investigated the possibility of purchasing mobile diesel rentals and related equipment. Yukon Energy was not successful in receiving any response for the purchase of diesel rentals at that time. However, responses were received for the purchase of transformers and fuel tanks.

Yukon Energy is currently negotiating the diesel rental contract for the period that commences after expiry of the current contract in April 2025. The process for a longer-term contract was competitively tendered. In December 2023, Yukon Energy issued a Request for Qualifications for Diesel Rental Power Generation (RFQF). The RFQF closed in January 2024. The primary purpose of the RFQF, as stated in the document, was to:

- Qualify proponents for Stage Two of the procurement process; and

- Gather input from qualified proponents to inform the subsequent stage.

Yukon Energy received four submissions to the RFQF. Proposals deemed non-responsive or failing to meet the specified requirements were excluded from further consideration in Stage Two. Yukon Energy aimed to secure the best overall solution by prioritizing quality, proven track records, and value in the proposals received. Following the evaluation, the results showed two proponents successfully met all mandatory and rated criteria outlined in the RFQF.

The evaluation process concluded in May 2024. However, due to time constraints, Yukon Energy extended its existing contracts with Finning Power Systems for the 2024/2025 season to ensure adequate diesel rental power generation capacity for the upcoming winter season.

Subsequently, in October 2024, one of the successful RFQF proponents informed Yukon Energy of its inability to proceed with a bid for Stage Two of the tender. Consequently, Yukon Energy has determined that it will enter into direct negotiations with the remaining successful proponent.

As part of the process, Yukon Energy has reaffirmed interest in purchasing generators and accessory equipment such as transformers and fuel tanks. As negotiations are not complete at the time of GRA preparation, Yukon Energy has assumed continued rental of all 22 units for revenue requirement purposes. Purchase of transformers and fuel tanks will also be determined later as they are dependant on the decision made for the generators.

3.3.3 Transmission and Distribution

As set out in Table 3.6, total transmission and distribution costs in the 2025 test year are forecast to be at $3.415 million, $3.831 million in the 2026 test year and at $3.438 million in the 2027 test year, or $0.171 million above the approved 2024 costs of $3.267 million. The average annual increase in non-labour transmission and distribution expenses is approximately 1.72% (2027 expenses over 2024 approved).

Table 3.6:
Transmission and Distribution Costs
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	$ 1,407	$ 1,430	$ 996	$ 1,567	$ 1,374	$ 1,480	$ 1,515
Brushing Cost	1,339	1,339	1,339	1,339	1,398	1,695	1,255
Other Non-Labour	722	498	641	834	643	656	669
Total T&D	$ 3,468	$ 3,267	$ 2,976	$ 3,740	$ 3,415	$ 3,831	$ 3,438

Forecast labour costs are expected to decrease by $0.057 million in 2025 from 2024 approved, increase by $0.107 million in 2026 and by $0.034 million in 2027. These changes from 2024 approved are impacted by assumed stabilization of overtime costs.

Other non-labour costs are forecast to increase through 2027 from 2024 approved by approximately 3% on an average annual compound basis from the average of 2023 and 2024 approved amounts. Other non-labour costs include:

- Material or contractor costs for inspection, cleaning, or testing of existing equipment;
- Tools and small supplies used for minor repairs or maintenance;
- Adjustment and hardware tightening, pole straightening, guy tightening, grounding/bonding repair;

- Trouble calls and troubleshooting (unless leading to major capital equipment repair/upgrade);
- Temporary fixes to prevent further damage, such as repairs to broken wires, poles, or transformers that restore functionality but do not increase capacity or extend useful life;
- Streetlight repair (lamp/bulb replacement);
- Metering point repair or meter accuracy check or meter recalibration;
- Joint use survey;
- Thermal scan; and
- Administrative expenses related to maintenance work.

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. Total brushing costs are forecast to decrease by $0.084 million in 2027 from 2024 approved.

Table 3.6.1:
Brushing Costs
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Transmission Brushing	$ 1,305	$ 1,131	$ 1,305	$ 1,305	$ 1,208	$ 1,502	$ 1,056
Distribution Brushing	34	208	34	280	190	193	199
% Transmission	97%	85%	97%	82%	86%	89%	84%
% Distribution	3%	15%	3%	18%	14%	11%	16%
Total Brushing Expense	$ 1,339	$ 1,339	$ 1,339	$ 1,585	$ 1,398	$ 1,695	$ 1,255

Yukon Energy enlisted ATCO Power (2010) Ltd. (ATCO) in 2023 and 2024 to prepare a 10-year vegetation management plan for transmission lines based on best practices to minimize unscheduled maintenance and effectively manage rights of way (ROWs) according to regulation (see Appendix 3.4). To develop a program for Yukon Energy, ATCO undertook a ground-based spatial inventory patrol of the approximately 1,116 km ROW to understand the scope of mechanical vegetation management work that would be required in the next 10 years. The data gathered during the ground-based inventory patrol helps inform key decisions on the current and future state of Yukon Energy's vegetation management program. Using the data gathered from the inventory patrol, ATCO developed a 10-year plan for activities to manage grow-in and fall-in risks on Yukon Energy's entire transmission system.

Based on the vegetation inventory obtained, and ATCO recommendations, in 2025 all vegetation with 3.1 m to 3.5 m of clearance to the conductor will be removed. ATCO forecast these O&M costs to be $1.167 million. With the addition of $0.041 million of brushing administration, total transmission brushing cost in 2025 is $1.208 million.

Based on the vegetation inventory obtained, and ATCO recommendations, in 2026 all vegetation with 3.6 m to 4.0 m of clearance to the conductor will be removed on higher-priority lines L171, L170 and L173. The historical annual funding is insufficient to remove all vegetation with 4 m clearance in 2026. The table below shows the 2026 O&M forecast cost to remove all identified vegetation with 3.6 m to 4.0 m of clearance.

Table 3.6.2:
2026 O&M Forecast Cost to Remove Identified Vegetation with 3.6 m to 4.0 m of Clearance

Project	Trim	Slash	Mow	Total	2026 O&M Mechanical Work
Line Number	M^2	M^2	M^2	M^2	$000
L171	0	8,750	582,767	591,517	$520
L170	0	64,166	693,758	757,924	$769
L173	0	3,500	188,641	192,141	$170
Total	0	76,416	1,465,166	1,541,852	$1,459

ATCO forecast the 2026 O&M costs to be $1.459 million. With the addition of $0.043 million of brushing administration, total transmission brushing cost forecast in 2026 is $1.502 million.

Based on the vegetation inventory obtained, ATCO recommends that in 2027, all remaining vegetation with 3.6 m to 4.0 m of clearance to the conductor will be removed from the system. The table below shows the 2027 O&M forecast cost to remove all remaining identified vegetation with 3.6 m to 4.0 m of clearance.

Table 3.6.3:
2027 O&M Forecast Cost to Remove Identified Vegetation with 3.6 m to 4.0 m of Clearance

Project	Trim	Slash	Mow	Total	2027 O&M Mechanical Work
Line Number	M^2	M^2	M^2	M^2	$000
L178	0	68,460	386,350	454,810	$520
L172	0	180	49,215	49,395	$42
L169	282	0	0	282	$2
L355	0	1,425	49,318	50,743	$46
L254	0	1,668	0	1,668	$5
L177	0	10,984	160,015	170,999	$167
L174	0	675	14,396	15,071	$14
L176	0	900	32,732	33,632	$30
L180	0	100	11,340	11,440	$10
L356	0	25,350	115,060	140,410	$169
L250	0	864	6,670	7,534	$8
L453	0	0	1,656	1,656	$1
Total	282	110,606	826,752	937,640	$1,014

ATCO forecast the 2027 O&M costs to be $1.014 million. With the addition of $0.042 million of brushing administration, total transmission brushing forecast cost in 2026 is $1.056 million.

Distribution 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, 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.

3.3.3.1 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 2025 test year forecast at $2.180 million, the 2026 test year forecast at $2.555 million and the 2027 test year forecast at $2.128 million (or $0.312 million less than the approved 2023 costs of $2.441 million and $0.051 million above the approved 2024 costs of $2.077 million).

Table 3.7.1:
Transmission Costs
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	$ 656	$ 666	$ 343	$ 637	$ 565	$ 639	$ 648
Brushing Cost	1,305	1,131	1,305	1,305	1,208	1,502	1,056
Other Non-Labour	480	279	283	223	407	414	425
Total Transmission	$ 2,441	$ 2,077	$ 1,931	$ 2,165	$ 2,180	$ 2,555	$ 2,128

3.3.3.2 Distribution

Costs of operating and maintaining the distribution system are set out in Table 3.7.2. The total distribution costs for the 2025 test year are forecast at $1.235 million, the 2026 test year forecast is $1.276 million and the 2027 test year forecast is $1.310 million (or $0.120 million above the approved 2024 costs of $1.190 million).

Table 3.7.2:
Distribution Costs
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	$ 751	$ 764	$ 653	$ 930	$ 808	$ 841	$ 867
Brushing Cost	34	208	34	34	190	193	199
Other Non-Labour	242	219	358	611	236	242	244
Total Distribution	$ 1,027	$ 1,190	$ 1,045	$ 1,575	$ 1,235	$ 1,276	$ 1,310

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 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	$ 342	$ 350	$ 371	$ 425	$ 374	$ 388	$ 389
Transportation	632	632	695	705	692	706	720
Maintenance of Company Owned Properties	569	466	803	744	585	596	608
SCADA Communication	167	167	54	106	108	110	113
Total General O&M	$ 1,711	$ 1,615	$ 1,923	$ 1,980	$ 1,760	$ 1,801	$ 1,830

Labour costs are forecast to increase by $0.024 million in 2025 from 2024 approved, increase by $0.014 million in 2026 and increase by $0.001 million in 2027.

Total forecast costs in the non-labour General O&M categories in 2025 are $0.120 million higher than approved 2024 costs, increase by $0.028 million in 2026 and increase by another $0.028 million in 2027. Transportation expenses are forecast to increase $0.088 million through 2027 over 2024 approved. Maintenance of Company Owned Properties is expected to increase by $0.142 million through 2027 over 2024 approved. SCADA Communication expenses are forecast to decrease by $0.055 million through 2027 over 2024 approved.

Transportation costs are forecast to be higher than 2023 and 2024 approved as actual costs in 2023 and 2024 were higher than expected. The 2023 and 2024 approved amounts were based on recent years of low kilometers driven (average kilometres of 775,000 from 2020 through 2022), but as the economy recovered from the Covid pandemic, Yukon Energy experienced regular kilometers driven (876,000 kilometres driven in 2023). Below is a table showing kilometers driven by year.

Table 3.8.1:
Kilometers Driven by Year: 2018 to 2024

2018	2019	2020	2021	2022	2023	2024
945,000	844,000	780,000	773,000	771,000	876,000	856,000

More kilometers driven results in increased fuel and maintenance costs. Increased transportation costs also reflect the increase in gasoline prices.

Maintenance of Company Owned Properties is expected to remain relatively stable from 2023 approved, increasing on an average annual compound basis by approximately 1.7% through 2027. Actual costs in 2023 were exceptionally high for several reasons, including major staff housing maintenance costs and significant Whitehorse office building plumbing repairs.

3.3.5 Administration

As shown in Table 3.9, Administration expense is forecast to increase by $2.613 million in 2025 over 2024 approved, increase another $0.969 million in 2026 and by $0.772 million in 2027. Labour costs are forecast to increase by $0.429 million in 2025 over 2024 approved, increase by $0.850 million in 2026 and by $0.651 million in 2027, reflecting labour cost changes as well as FTE changes noted in Section 3.3.1. Non-labour costs are forecast to increase $2.184 million in 2025 over 2024 approved, increase by $0.119 million in 2026 and by $0.122 million in 2027. Administration expense includes the new cost category of Capital Projects Studies, detailed below.

Table 3.9:
Administration
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	$ 7,634	$ 8,311	$ 7,879	$ 8,397	$ 8,740	$ 9,590	$ 10,240
Resource Planning	108	108	71	60	59	60	62
Communications	175	175	170	170	221	225	230
Customer Accounting	423	356	337	287	332	338	345
Environmental Mgmt	361	361	667	899	953	972	991
General	852	834	898	1,031	945	964	983
Information Systems	1,491	1,441	1,369	1,495	1,715	1,750	1,785
Fish Hatchery	222	222	241	267	270	275	281
Safety	207	207	209	227	235	239	244
Training	150	150	120	112	168	171	175
Recruitment	439	457	486	405	514	512	573
Board of Directors	419	311	440	410	372	380	387
Union	121	91	74	91	96	110	61
Regulatory Affairs	8	11	14	2	4	4	4
Material Management	23	23	36	44	27	28	28
Contracting	58	18	42	55	39	40	40
Professional Development	15	15	6	0	15	15	16
Capital Projects Studies	0	0	0	0	1,000	1,000	1,000
Total Administration	$ 12,705	$ 13,092	$ 13,060	$ 13,951	$ 15,705	$ 16,674	$ 17,446

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

- **Communications** – Forecast to increase $0.046 million in 2025 over 2024 approved primarily due to a $0.050 million cost increase to operate the Fish Viewing Facility.
- **Environmental Management** – In the 2023/24 GRA Yukon Energy had forecast costs of $0.798 million; however, the Board approved only $0.361 million as it found Yukon Energy had not supported the accuracy of the 2023-2024 forecast environmental costs. Actual 2024 costs were $0.899 million. Environmental management costs are not discretionary, but represent the

costs associated with renewed water use licenses and air quality monitoring programs. The environmental management cost of $0.953 million forecast in 2025 is comprised of:

- Aishihik Generating Station (AGS) Monitoring and Adaptive Management Program (MAMP) of $0.450 million;
- Mayo Generating Station (MGS) MAMP of $0.095 million;
- Whitehorse Rapids Generating Station (WRGS) MAMP of $0.325 million; and
- Other costs of $0.083 million for travel, EMS, environmental compliance and reporting and hazardous waste management.

Yukon Energy projects 2026 and 2027 could be substantially higher than forecast as they could incur a full year of monitoring costs for MGS and WRGS rather than a partial year as in 2025.

- **General** – Forecast to increase $0.111 million in 2025 over 2024 approved primarily due to a requirement from in AGS licence renewal to fund a community liaison position for Champagne and Aishihik First Nations.

- **Information Systems** – Forecast to increase $0.275 million in 2025 over 2024 approved primarily due to the following increases totalling $0.365 million (other changes provided savings overall):

  - Infrastructure, data circuit and backup internet communications increase of $0.115 million to $0.555 million; and
  - Software licensing increase of $0.250 million to $0.555 million.

- **Fish Hatchery** – Yukon Energy has been responsible for operating the Fish Hatchery since 1984 when the fourth turbine was added, and the Department of Fisheries and Oceans required the Whitehorse Fish Hatchery to be built and operated. Over the years, Yukon government has provided approximately 50% funding which has helped to reduce costs and ratepayer impacts. However, during the renewal process of the agreement with Yukon government in 2025, Yukon Energy was notified that Yukon government would maintain their funding at the 2022 level and would not increase their funding even though costs to operate the Fish Hatchery have significantly increased.

- **Recruitment Expenses** – Forecast to increase $0.057 million in 2025 over 2024 approved primarily due to increased human resource costs associated with increased employee complement as well as increased costs for labour issues as described in Section 3.3.1. The 2027 forecast is expected to be higher than 2025 and 2026 due to forecast costs of CEO recruitment.

- **Board of Directors** – Expenses are forecast to increase by $0.061 million in 2025 over 2024 approved but are forecast to be $0.047 million less than 2023 approved. Board spending in a particular year is dependent on strategic issues at the time, so are not necessarily fully predictable or consistent from year to year.

Administration expenses are forecast to be lower in 2027 from 2024 approved in:

- Resource Planning;
- Customer Accounting;
- Union; and
- Regulatory Affairs.

3.3.5.1 Capital Projects Studies

As part of the 2023/24 General Rate Application, the Board in Board Order 2024-05 paragraph 312 stated:

> "… *To reduce the impacts of capitalizing significant amounts of AFUDC on ratepayers, the Board directs YEC to examine and redefine its processes for similar major deferred capital projects and to only capitalize those costs once it is determined that there is a reasonable probability that that project will go forward and to reflect, as necessary, any changes that may be required to YEC's capitalization policies and supporting documents. On a go-forward basis, YEC is to explore and provide an alternative for the treatment of costs incurred for such projects until it has established a reasonable probability that the project will proceed. For example, this could be done by*

expensing the costs as incurred (until a reasonable probability of proceeding is determined) or treating the costs as no-cost capital (with or without debt and/or equity financing)."

Yukon Energy performed a comprehensive review of its capitalization policies and has developed a new policy based on extensive research of International Financial Reporting Standards (IFRS) and industry guidance. Effective January 1, 2025, Yukon Energy has implemented the policy FX-001 Criteria for Capitalization. A copy of this policy has been provided in Appendix 5.3. In summary, this policy complies with IFRS standards and requires expensing of costs that do not meet the capitalization criteria. As a result, the category of Feasibility Studies will cease to exist in the future as no new projects will be capitalized as costs will no longer meet the capitalization criteria. Feasibility studies continue to be included in this GRA for completion of studies already included as part of previous GRA until those projects are completed and fully amortized.

The change in the accounting treatment does not change the need for Yukon Energy to perform these studies. Based on industry guidance, Yukon Energy created a Capital Projects Studies budget to fund projects in the early stages and do not meet the capitalization criteria. These project or study costs will be expensed in the following situations:

Table 3.9.1:
Summary of Conditions for Expensing Project or Study Costs

Phase	Key Objectives	Classification
Identification Phase (Needs Stage)	• Conceptual design • Confirm project scope and schedule • Identify potential alternatives • Confirm project team resourcing and accountabilities	O&M (CPS)
Identification Phase (Conceptual Design Stage)	• Analyze agreed conceptual alternatives • Identify leading alternative to move into Feasibility Desing stage • Ensure capitalization requirements are met before moving into Feasibility Design Stage	O&M (CPS)

In order to determine an appropriate budget for Capital Projects Studies, Yukon Energy reviewed historic Feasibility Study spending. This analysis showed that the average total feasibility project spending from 2017 to 2024 was $1.455 million per year. However, these results were skewed by the inclusion of larger projects considered feasibility, therefore, a second analysis was prepared excluding large feasibility studies. The average total small feasibility spending from 2017 to 2024 was $1.140 million. Based on this, Yukon Energy is proposing a revenue requirement cost of $1.000 million for each test year. This treatment will be beneficial to ratepayers as it is less than historic feasibility study spending and eliminates AFUDC on these projects.

Projects that Yukon Energy is considering under this category include the following:

- Grid modernization strategy research, studies and pilots;
- Wareham spillway concrete assessment;
- ERP replacement research;
- Development or requirements for a drafting drawing management system;
- Southern Lakes groundwater study;
- Dam safety audit;
- T&D emergency parts and stocking study;
- WDO P126 Whitehorse diesel plant renewal study;
- Thermal and permitting studies;
- S251 StatCom retuning study;
- Hazardous building materials assessment;
- T9 transformer critical spare business case study;
- Dawson diesel plant lifecycle study;
- Aishihik elevator moisture reduction assessment;
- WD0 units voltage mis-regulation study;
- Mayo diesel transformer foundation study;
- Marwell flood prevention design;
- Phone system replacement study
- MCC inspection, condition assessment renewal option analysis;
- Communications data/OT/SCADA/IT link strategy and plan;
- Turbine welding standards;
- Pressure vessel certification program;
- Aishihik fiber link install and connect study;
- PLT energized services development;
- Asset appraisals;
- Skagway shoreside power study.

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.

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

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Insurance	$ 2,190	$ 2,417	$ 2,218	$ 2,504	$ 2,993	$ 3,329	$ 3,393
Reserve Appropriation (RFID)	616	616	616	616	1,063	1,063	1,063
Total	$ 2,805	$ 3,033	$ 2,834	$ 3,120	$ 4,056	$ 4,392	$ 4,455

Note: The proposed RFID total annual appropriation of $1.063 million reflects a $0.554 million annual forecast based on a ten-year average plus amortization of the 2024 balance over a ten-year period [$5.086 million over 10 years = $0.509 million/year]. The 10-year average spending is about $0.962 million, as reviewed in Table 3.11.

3.3.6.1 Insurance

Yukon Energy's costs for insurance in 2025 are forecast to increase by $0.576 million above 2024 approved. Costs in 2025 are forecast to increase due to mid-year market rate adjustments (overall rate increase of 25% 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. The rate increases expected by Yukon Energy as part of 2025 renewals are higher than normal due to recent insurance claims such as the Mayo Intake Gate and AH1 Field Loss failures where Yukon Energy is expecting insurance proceeds of approximately $7.161 million in 2025 (net of $1.000 million deductible each). As insurance renewals are mid-year, the increased 2025 renewal rate results in a larger than normal increase for fiscal 2026, at $0.336 million. Insurance becomes normalized in 2027 with an increase of $0.063 million, or 1.9%.

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:

- Continued to participate the Canadian Electricity Risk Managers Committee and demonstrate sound risk management practices to insurers in advance of policy renewals.

- Completed a public tender process for insurance broker services to confirm that ratepayers are receiving the best value for money from this annual expense.

In partnership with the new broker (Marsh), the following was completed in 2024:

- A successful transition to the new broker and an adjustment of all casualty policy renewal dates to better align with industry preferences.
- Premium savings or significant coverage improvements in all lines of coverage.
  - Negotiations with the lead insurer were tough and prolonged, with five iterations of their quote being provided, and settlement of flat rates subject to coverage restrictions.
- A risk control site visit to Aishihik and Whitehorse that included two specialists from Marsh as well as the lead insurer.
- Initiation of the claims process for two separate events, including hosting insurance adjusters at site.

While Yukon Energy expects a significant increase in the cost of the 2025 renewal, the following actions are planned to potentially reduce costs in the future:

- Communication to insurers of root cause analysis findings and lessons learned related to recent claims.
- Risk control site visit to Mayo and Dawson to view new assets and upcoming civil work at Wareham Lake.
- Risk financing optimization analysis to determine the potential of retention changes to offset rate increases.
  - Yukon Energy, in conjunction with its new insurance broker, Marsh, is in the process of assessing the property insurance deductible. Increasing the deductible would result in lower annual premiums. If Yukon Energy is able to perform more preventative maintenance with increased capital funding in this area, as well as asset health improvement from the implementation of Enterprise Asset Management (EAM) and asset management, the risk of large failures and insurance claims in the future should be reduced.

- Exploring an alternative lead insurer on our property program as part of the renewal strategy.
- Health and safety practices such as fire watch requirements, updates to Emergency Preparedness Plans (EPPs) and operational changes as provided by Yukon Energy's insurance broker, Marsh, as part of a Property and Machinery Risk Evaluation Report performed in 2024.

3.3.6.2 Reserve for injuries & damages (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 versus 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. No changes were made during the 2023/24 GRA.

As shown in Table 3.11 the 10-year average of charges to the RFID increased to $0.962 million.

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

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Average
Net Annual Costs	$ 193	$1,018	$ 666	$ 651	$ 62	$1,233	$ 813	$2,006	$ 555	$2,420	$ 962

The large expense in 2024 reflects the $1.000 million deductible for each of the costs associated with the Mayo Intake Gate and AH1 Field Loss failures. The total charges in 2024 of other events totalled $0.420 million, including $0.228 million of costs spent in 2024 regarding the WG2 Ground Generator failure that occurred in 2023. Therefore, total charges of other events due to events occurring in 2024 was only $0.192 million.

In previous GRA's, Yukon Energy would forecast net annual costs based on the 10-year average. However, due to the outlier of costs in 2024, and noting that the normal costs in 2024 were only $0.192

million, Yukon Energy believes the 10-year average is not reflective of future annual costs. For the test years, Yukon Energy has forecast net annual costs of $0.554 million based on the 2023 approved costs. Therefore, Yukon Energy proposes the annual appropriation base be $0.554 million (instead of $0.962 million).

Table 3.11.1 below shows that the RFID balance owing from customers at the end of 2024 was $5.086 million, reflecting higher recent costs.

Table 3.11.1:
RFID Continuity Schedule
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Opening Balance	-$3,343	-$3,281	-$3,343	-$3,282	-$5,086	-$4,577	-$4,069
Annual Appropriation	616	616	616	616	1,063	1,063	1,063
Net Annual Costs	-554	-682	-555	-2,420	-554	-554	-554
Closing Balance	-$3,281	-$3,347	-$3,282	-$5,086	-$4,577	-$4,069	-$3,560

Consistent with calculations in previous GRA's, Yukon Energy is proposing the opening RFID balance (of $5.086 million at the end of 2024) be amortized over a period of ten years (or $0.509 million per year).

The proposed total annual appropriation for the test years is $1.063 million, calculated as the base appropriation of $0.554 million plus $0.509 million reflecting amortization of the opening balance.

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 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Property Taxes	$ 758	$ 777	$ 756	$ 759	$ 771	$ 790	$ 806

Property taxes are forecast to decrease $0.006 million in 2025 from 2024 approved, increase by $0.019 million in 2026 and increase by $0.016 million in 2027 due to rate increases and valuation updates. Actual property taxes decreased in 2025 due to lower-than-expected rate increases and valuation updates. Forecast property taxes in 2025 are based on invoiced cost for the period January 1, 2025 through June 30, 2025, increasing by 3% from July 1, 2025 through June 30, 2026, increasing by 2% July 1, 2026 through June 30, 2027, and increasing by 2% on July 1, 2027.

3.4 DEPRECIATION AND AMORTIZATION

Yukon Energy's forecast proposed 2025, 2026 and 2027 expenses related to depreciation of capital assets and amortization of deferred charges is shown in Table 3.13.

Table 3.13:
Depreciation and Amortization
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Fixed Asset Depreciation	$ 14,244	$ 15,350	$ 16,005	$ 15,719	$ 20,658	$ 24,529	$ 27,658
Less: Contributions	(5,656)	(5,679)	(6,480)	(5,705)	(5,933)	(6,358)	(6,684)
Less: Lewes River Boat Lock insurance recov	-	-	-	-	(1,507)	(1,507)	(1,507)
Less: Amortization of fire insurance recoveries	(262)	(262)	(262)	(262)	(262)	(262)	(262)
Less: Disallowed Depreciation	(51)	(51)	(51)	(51)	(51)	(51)	(51)
Plus: Amortization of deferred charges	4,536	5,345	3,690	5,436	7,006	7,488	6,893
Plus: Net Salvage Annual Appropriation	-	-	-	-	350	350	350
Total Depreciation & Amortization	$ 12,811	$ 14,703	$ 12,902	$ 15,137	$ 20,261	$ 24,190	$ 26,398

The Board in Order 2024-05, Appendix A, paragraph 189 directed Yukon Energy to file a revised Schedule 3B "to include working formulae in the column of the schedule where the forecast amortization expense is being calculated, to ensure the calculation of the forecast depreciation expense on current year additions." Accordingly, Schedule 3B in Tab 7 provides details of the amortization expense calculations for each 2025, 2026 and 2027 test years, including depreciation expense for the current year additions as directed by the Board with working formulae intact.

3.4.1 Fixed Asset Depreciation

Forecast fixed asset depreciation expense is $20.7 million in 2025, $24.5 million in 2026 and $27.7 million in 2027 (as compared to $15.4 million in 2024 approved).

The Board in Order 2024-05, Appendix A, paragraph 189 directed Yukon Energy to file a revised Schedule 3A "in which it will insert a column indicating the depreciation rate being used, and to include working formulae in the column of the schedule where the forecast depreciation expense is being calculated, including the forecast depreciation expense on current year additions."

The Board in Order 2024-13, Appendix A, paragraph 20 noted that "for forecast revenue requirement purposes, a new asset is assumed to be capitalized at the mid-point of a given test year and therefore provides for a half-year of depreciation expense and a half-year of return on rate base. This practical application of the mid-year convention serves to avoid any requirement for the utility to estimate exact dates of asset capitalization as it impacts depreciation expense and return calculations given the inherent assumption that capitalization occurs at the mid-point of the year." The Board further stated that "in the Board's view, Yukon Energy's rationale for including current-year capital additions on a mid-year basis for determining its return on rate base but not following the same practice for depreciation expense purposes is inconsistent."

During the 2023/24 GRA Compliance Filing Yukon Energy noted that it uses Microsoft Great Plains to track its assets and calculate depreciation and amortization and system depreciation estimate generates no depreciation and amortization expense for the assets with zero net book value, i.e., fully amortized assets. Yukon Energy further noted that to simplify the Board's review process, in future GRAs, the calculation of depreciation expenses for forecast years be based on the approach that takes:

1) The asset cost by asset class for the prior year times depreciation rate; plus,

2) Half of current year additions by asset class times depreciation rate to get the total depreciation expense for the test year.

Yukon Energy noted that this would also be consistent with how AEY forecasts depreciation expenses in its GRAs.

Accordingly, Schedule 3A in Tab 7 provides details of the depreciation expense calculations for each of the 2025, 2026 and 2027 test years as described above, including depreciation expense for the current year additions as directed by the Board with working formulae intact.

There were no changes in depreciation rates from the 2023/24 GRA, and the rates used in Schedule 3A are the same as approved by the Board except for the Battery Energy Storage System (BESS), which is a new asset class for Yukon Energy. For the BESS, Yukon Energy used 20-year life consistent with the information provided during the BESS Part 3 hearing.

3.4.2 Contributions

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 $5.679 million in 2024 approved to $5.933 million forecast in 2025, $6.358 million forecast in 2026, and $6.684 million forecast in 2027.

3.4.3 Amortization of Lewes River Boat Lock Insurance Gain

As identified in the 2023/24 GRA, Yukon Energy incurred damages and costs to the Lewes River Boat Lock due to the largest recorded flooding event along the Yukon River in 2021. Forecast costs in work-in-progress at the end of 2024 were $15.514 million. However, this project has been put on hold. Costs relating to the project are summarized in this Application in Section 5.2.2. Further description of the project is shown in Appendix 5.1B.

Also included in the work-in-progress balance at the end of 2024 in the 2023/24 GRA was forecast contributions of $4.520 million, representing the forecast insurance gain on the boat lock. Yukon Energy intended on keeping this amount in work-in-progress until the Boat Lock was repaired and then planned to request it be amortized on a similar basis to the new boat lock. However, as this project has been put on hold and has an unknown future, Yukon Energy is requesting the gain of $4.520 million be amortized to revenue over the 3-year term of this application, being 2025, 2026 and 2027, or $1.507 million per year. This treatment results in reducing the rate impacts of each test year. Accounting rules require recognition of the insurance proceeds immediately.

3.4.4 Amortization of Deferred Charges

Deferred charges include planning and study costs, licensing costs related to maintaining licences for Yukon Energy's hydro facilities and air emission permits, regulatory costs, dam safety costs, intangible assets as well as amortization and appropriations of regulatory deferral accounts. Table 3.13.1 shows details of deferred charges amortization [excluding amortization of contributions].

Table 3.13.1:
Amortization of Deferred Charges
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Amortization of Feasibility Costs	$ 1,935	$ 2,134	$ 1,081	$ 2,232	$ 2,507	$ 2,426	$ 1,846
Amortization of Relicensing Costs	820	812	820	812	1,465	1,881	2,075
Amortization of Regulatory Costs	540	1,142	541	1,151	1,319	1,391	1,367
Amortization of Dam Safety Costs	51	51	51	51	70	64	39
Amortization of Intangibles	718	734	726	718	833	914	976
Amortization of Vegetation Management	222	222	222	222	222	222	0
Hearing Reserve Annual Appropriation	250	250	250	250	590	590	590
Total Amortization	$ 4,535	$ 5,345	$ 3,690	$ 5,436	$ 7,006	$ 7,488	$ 6,893

Details of Regulatory Deferral Accounts are described in the next section.

3.4.4.1 Hearing Cost Reserve

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 2023 and 2024 was $0.250 million which is at the YUB Order 2018-10 approved level and reflects expiry of the 2016 credit balance amortization.

Based on the number of recent hearings and the level of intervention, the cost of regulatory proceedings has been significant. The Government of Yukon is working on amendments to the *Public Utilities Act,* including considering changes to the Board's review processes to improve their efficiency and effectiveness, such as:

- Are there measures that would make the Board's review processes move more quickly, smoothly or predictably?

- Are there areas where the Board may reduce time or expense, while still maintaining fairness, transparency and principled, evidence-based decision-making?

Until there is a change in the regulatory process, costs are expected to remain high. Yukon Energy has taken steps to reduce its costs such as internal preparation of its GRA's, submission of a longer-term GRA and reduction of administration costs. However, Yukon Energy cannot control intervenor costs and effects on Yukon Energy and Board costs for questions that provide no value to the proceeding. As requested in the 2023/24 GRA, Yukon Energy is requesting a limit on intervenor questions to minimize risk of irrelevant or insignificant questions. Below are recent cost claim awards relating to Yukon Energy hearings ($000):

Table 3.13.1.1: Cost Claim Awards relating to Yukon Energy Hearings ($000)

	2017/18 GRA	2017/18 GRA second CF	BESS Part 3	2021 GRA	Atlin EPA PUA S18 Review	2021 GRA R&V	2021 LWRF	2022 LWRF
YEC	$515.2	$41.2	$69.4	$413.8	$179.9	$23.1		
YUB	$368.2	$32.2	$135.7	$409.7	$211.9	$109.7	$10.2	$17.8
UCG	$39.2	$12.1	$14.4	$18.3				
JM	$6.4							
CW	$78.2	$7.5		$55.6				
NY				$6.2	$1.8			
Total	**$1,007.2**	**$93.0**	**$219.5**	**$903.5**	**$393.5**	**$132.9**	**$10.2**	**$17.8**

Based on the recent high cost of regulatory hearings, Yukon Energy requests approval of an annual appropriation increase from $250,000 per year to $400,000 per year. In addition, Yukon Energy requests approval of annual amortization of the 2024 balance of $0.951 million over a five-year period from 2025 to 2029 years [$0.190 million/year]. This would result in a total annual appropriation of $0.590 million.

The Proposed 2025, 2026 and 2027 column 'Annual Costs' include high-level estimates of hearing related costs such as the cost awards for the Yukon Energy 2023/24 GRA and the Yukon Energy 2025-2027 GRA. Yukon Energy will update the account balance based on information available at the time of the compliance filing. These estimates do not directly affect the revenue requirement as revenue requirement is based on the annual appropriation that is approved by the Board.

Table 3.13.1.2 shows the hearing cost reserve account continuity schedule.

Table 3.13.1.2:
Hearing Cost Reserve Account Continuity Schedule
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Opening Balance	$881	$1,016	$881	$1,046	$951	$1,261	$1,471
Annual Appropriation	-250	-250	-250	-250	-590	-590	-590
Annual Costs	386	0	416	155	900	800	100
Closing Balance	$1,016	$766	$1,046	$951	$1,261	$1,471	$981

Notes:

1. The annual appropriation of $0.590 million is based on the estimated annual cost of $0.400 million plus amortization of the 2024 balance over a five-year period [$0.190 million/year].

2. The costs under proposed columns are forecasts and the hearing related costs are only included in the hearing reserve after approval by the YUB.

3.4.4.2 Vegetation Management Deferral

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. Yukon Energy is not proposing any changes for the test years. This deferral account is scheduled to expire on December 31, 2026. Table 3.13.1.3 shows the deferred vegetation management continuity schedule.

Table 3.13.1.3:
Deferred Vegetation Management Continuity Schedule
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Opening Balance	$ 886	$ 665	$ 886	$ 665	$ 443	$ 222	$ -
Annual Deferred Costs	0	0	0	0	0	0	0
Annual Amortization	(222)	(222)	(222)	(222)	(222)	(222)	0
Closing Balance	$ 665	$ 443	$ 665	$ 443	$ 222	$ -	$ -

3.4.4.3 Defined Pension Deferral

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 3.13.1.4 provides a continuity schedule for this deferral account. Yukon Energy is not proposing amortization of the deferral account balance at this time as the balance is not significant.

Table 3.13.1.4:
Defined Pension Deferral Account Continuity Schedule
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Opening Balance	$ (62)	$ (62)	$ (62)	$ (85)	$ (63)	$ (63)	$ (63)
Additions	0	0	(22)	22	0	0	0
Annual Amortization	0	0	0	0	0	0	0
Closing Balance	$ (62)	$ (62)	$ (85)	$ (63)	$ (63)	$ (63)	$ (63)

3.4.4.4 IPP Purchase Cost Deferral

As noted in Section 3.6.4, the Board Order 2024-05 approved IPP Purchase Cost Deferral Account that provides deferral account treatment of some costs related to the IPPs.

Table 3.13.1.5 provides a continuity schedule of the deferral account. Yukon Energy is not proposing amortization of the deferral account balance at this time as the balance is not significant.

Table 3.13.1.5:
IPP Purchase Cost Deferral Account Continuity Schedule
($000)[2]

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Opening Balance	$ -	$ -	$ 26	$ 26	$ 93	$ 93	$ 93
Additions	0	0	0	67	0	0	0
Annual Amortization	0	0	0	0	0	0	0
Closing Balance	$ -	$ -	$ 26	$ 93	$ 93	$ 93	$ 93

[2] Yukon Energy in its 2023/24 GRA proposed IPP deferral account that defers the variances between the actual IPP purchase costs and approved purchase costs less any LTA thermal displacement benefits. The 2023 opening balance for the deferral account was $0.026 million based on 2022 results determined based on Yukon Energy's proposed deferral account. However, the Board Order 2024-5 did not approve the deferral account as proposed by Yukon Energy but approved IPP Purchase Cost Deferral Account for Yukon Energy on the same basis as that approved for AEY.

3.4.5 Net Salvage & Reserve for Site Restoration

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.

The Board had provided a similar directive to AEY. AEY in it 2023/24 GRA proposed the re-instatement of the pre-collection of future net salvage costs using the net salvage per cent estimates as determined based on the traditional net salvage study. AEY's proposal also included a simultaneous re-instatement of the use of the amortization of reserve differences mechanism for net salvage. The Board, in its Order 2024-01, paragraphs 114 and 115, stated that it "accepts AEY's current method for estimating net salvage costs as originating with an allocation per cent applied to total actual project costs. The Board finds this allocation method to be reasonable in the circumstances of AEY, and results in efficiencies when compared to the costs associated with tracking actual incurred net salvage costs on a project-by-project basis" and "with respect to re-instating the pre-collection of net salvage costs through depreciation expense, the Board also finds it is reasonable to address now, any intergenerational inequity concerns associated with the potential for having unfunded net salvage costs in the future."

In the 2023/24 GRA, Yukon Energy highlighted that the balance was forecast to reach $2.0 million by 2023, however, it did not propose any annual provisions as the net salvage study was not conducted at that time.

In 2024, Yukon Energy retained Bowman Economic Consulting, through a request for a pricing proposal, to review Yukon Energy's Future Removal and Site Restoration (FRSR) provisions. The study explored two options in regard to the net salvage provisions: a traditional approach and a capitalization approach. The study results show that under the traditional approach, the annual net salvage provisions would be about $4.742 million, while under the capitalization approach, the annual provisions should be based on the gross plant times 0.042%, which is approximately $0.350 million. Based on the recommendations in the study, Yukon Energy is proposing to adopt the capitalization approach with the annual provisions of $0.350 million for the 2025, 2026 and 2027 test years to build up the FRSR reserve balance. In future GRAs, Yukon Energy will provide updated annual appropriation based on 0.042% as recommended in the study and the forecast gross plant cost. The annual appropriation of $0.350 million is included as a separate line item under depreciation expense without requiring a change in depreciation rates. A copy of the study is provided in Tab 9 of this Application.

Table 3.13.2 provides the continuity schedule of the reserve for site restoration.

Table 3.13.2:
Reserve for Site Restoration Continuity Schedule
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Opening Balance	$ 2,689	$ 1,966	$ 2,689	$ 2,036	$ 2,036	$ 2,386	$ 2,736
Annual Appropriation	0	0	0	0	350	350	350
Annual Costs	(723)	0	(653)	0	0	0	0
Closing Balance	$ 1,966	$ 1,966	$ 2,036	$ 2,036	$ 2,386	$ 2,736	$ 3,086

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

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 for 2023 and 2024, as well as forecast spending for 2025, 2026 and 2027, is provided in Tab 5 of this Application. Table 3.14 provides Net Rate Base at mid-year as approved in 2023 and 2024, actual for 2023 and preliminary actual for 2024, and forecasts for the 2025, 2026 and 2027 test years.

Table 3.14:
Mid-Year Net Rate Base[3]
($000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Mid-Year:							
Net plant in service							
Before contributions	$ 503,456	$ 539,442	$ 499,789	$ 528,365	$ 579,222	$ 687,976	$ 791,290
Less contributions	179,834	176,038	181,128	182,120	180,228	181,527	182,407
Net plant in service	323,622	363,404	318,661	346,245	398,994	506,449	608,883
Working capital	8,215	8,697	8,243	8,919	9,572	9,880	10,052
Net Rate Base	$ 331,837	$ 372,100	$ 326,904	$ 355,164	$ 408,566	$ 516,329	$ 618,935

Yukon Energy's 2025 mid-year forecast net rate base in this Application is $408.6 million (an increase of $36.5 million or 9.8% from 2024 approved mid-year net rate base). The forecast mid-year net rate base for 2026 is $516.3 million, an increase of $107.8 million or 26.4% over 2025 forecast. The forecast mid-year net rate base for 2027 is $618.9 million, an increase of $102.6 million or 19.9% over 2026 forecast.

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 $579.2 million in 2025 (a $39.8 million increase over 2024 approved mid-year balance), forecast to increase by $108.8 million in 2026 and forecast to increase by $103.3 million in 2027. The major increases over the 2024 approved reflects sustaining capital investments, as well as investments to address capacity planning requirements as provided in Tab 5.

Mid-year contributions is forecast at $180.2 million in 2025, $181.5 million in 2026 and $182.4 million in 2027, compared to $176.0 million approved in 2024.

[3] Net plant in service at year end 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, Defined Pension and IPP Cost Deferral Accounts]. Please see Schedule 3 in Tab 7 for details.

The balance of the change in net rate base from mid-year 2024 approved to mid-year 2025, 2026 and 2027 reflects increased working capital ($0.876 million increase in 2025 forecast over 2024 approved, an increase of $0.308 million in 2026 and a further increase of $0.172 million in 2027).

The total forecast return on Yukon Energy's mid-year net rate base for 2025 is $23.8 million, increasing to $30.4 million for 2026 and $37.6 million for 2027 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). The forecast Return on Rate Base for 2025 reflects an increase of 12% ($2.477 million) over the 2024 approved amount, an additional increase of 28% ($6.658 million) in 2026, and the 2027 forecast reflects a further increase of 24% ($7.163 million). The increase primarily reflects a 9.8% increase in mid-year net rate base in 2025 over 2024 approved, an increase of 26% in 2026, and a further increase of 20% in 2027. Yukon Energy's capital structure continues to be financed with 60% long-term debt and 40% equity.

As set out in Table 3.15, Yukon Energy seeks approval of a forecast average cost of capital of 5.81% for 2025, 5.89% for 2026 and 6.07% for 2027. This reflects changes to the average interest rate on debt. Yukon Energy is not proposing a change to the 2024 approved return on equity (9.15%) or capital structure (60% debt and 40% equity).

Table 3.15:
Cost of Capital

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Average Cost of Debt	3.29%	3.43%	3.13%	3.15%	3.56%	3.72%	4.02%
Return on Equity	9.15%	9.15%	7.04%	7.89%	9.15%	9.15%	9.15%
Average Cost of Capital	5.63%	5.72%	4.79%	5.08%	5.81%	5.89%	6.07%

Yukon Energy's forecast deemed mid-year capital structure for 2025 is comprised of $243.7 million in long-term debt and $164.7 million in common equity, $309.8 million in long-term debt and $206.5 million in common equity for 2026, and $371.4 million in long-term debt and $247.6 million in common equity for 2027 (see Schedule 4 of Tab 7).

3.5.1 Cost of Debt

The forecast 2025 average cost of long-term debt at 3.56% is 13 basis points higher than the 2024 approved cost of 3.43%, the forecast for 2026 is 3.72% which is 16 basis points higher than the 2025 forecast, and the forecast for 2027 is 4.02% which is 30 basis points higher than the 2026 forecast primarily reflecting higher interest rates for new debt and expiry or renewal conditions of old debt at lower rates.

Yukon Energy's long-term debt consists of the following instruments as at January 1, 2025 (see Schedule 11 of Tab 7):

Table 3.15.1:
Outstanding Debt

Lender	Outstanding Balance	Interest Rate	Interest & Principal Details
YDC	$55.620M	3.94%	Interest payable monthly with annual principal payments
TD Bank	$19.403M	3.40%	Interest payable monthly with monthly principal payments
YDC	$17.520M	5.46%	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.
YDC	$13.430M	2.21%	Interest payable annually with annual principal payments
YDC	$12.136M	2.95%	Interest payable monthly
TD Bank	$6.552M	2.06%	Interest payable monthly with monthly principal payments
YDC	$5.505M	2.40%	Interest payable monthly
TD Bank	$5.659M	2.64%	Interest payable monthly with monthly principal payments
YDC	$2.871M	2.90%	Interest payable monthly
TD Bank	$4.175M	2.06%	Interest payable monthly with monthly principal payments
YDC	$3.959M	1.56%	Interest payable monthly
TD Bank	$6.850M	2.88%	Interest payable monthly with monthly principal payments
TD Bank	$17.269M	4.07%	Interest payable monthly with monthly principal payments
YDC	$6.274M	4.10%	Interest payable quarterly with quarterly principal payments
CAFN	$1.000M	ROE[4]	Interest payable annually
YDC	$27.254M	4.30%	Interest payable quarterly with quarterly principal payments

[4] The per annum interest rate applicable to the principal amount shall be the actual final rate of return on equity for Yukon Energy's utility regulatory income for the actual year most recently filed with the YUB under section 25(1) of the *Public Utilities Act*. This long-term debt is associated with the installation of the third hydro turbine at the Aishihik hydro plant.

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 $73.664 million in 2025, $81.572 million in 2026 and $57.656 million in 2027, at an annual interest rate of 4.55%.[5] As per Board Order 2018-10, the interest rate on new test year debt is determined by a formulaic approach based on the long-term Canada Bonds rate plus 120 basis points (Government of Canada Long-Term Bond Benchmark at 3.35% as of January 28, 2025).

3.5.2 Return on Common Equity

The forecast return on equity for both test years is proposed at 9.15%, equal to the 2024 approved rate. 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 2025, 2026 and 2027 test years is 9.15%.

3.6 STABILIZATION MECHANISMS

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

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

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[5] During the BESS Part 3 hearing, Yukon Energy proposed that investment opportunity to be provided to the First Nations by structuring the debentures arrangements as a benefit, where Yukon Energy pays the interest on debentures based on the actual rate of return on equity, however, for rate setting purposes Yukon Energy will use the cost of debt to remove impact on ratepayers. The variance between the actual interest rate and interest expense included in the rates will be charged against Yukon Energy's retained earnings. The Board, in its Report dated June 30, 2021 stated that it "accepts YEC's commitment that ratepayers will not be adversely impacted by the debenture investment opportunity." Accordingly, the Application assumes all new debt, including any new debt related to the FN debentures, with an interest rate at 4.55%, which is based on the Bank of Canada benchmark plus 120 basis points.

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 Yukon Energy's 2017/18 GRA request to incorporate references to LNG pricing in the Rider F policy, noting that it was reasonable for Yukon Energy 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 Yukon Energy'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 Yukon Energy.

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 3.13.1.4 in Section 3.4.4.3 provides a continuity schedule for this deferral account.

3.6.4 IPP Purchase Cost Deferral Account

Board Order 2024-5 approved IPP Purchase Cost Deferral Account for Yukon Energy on the same basis as that approved for AEY.

The deferral account, as approved by the Board, provides deferral account treatment for the following costs:

i) Constraint payments paid to IPPs in accordance with the requirements under the EPAs applicable to IPP projects;

ii) Maintenance costs related to IPP projects; and

iii) Third party consulting costs (including legal costs) incurred by Yukon Energy related to the development and implementation of the EPAs.

Table 3.13.1.5 in Section 3.4.4.4 provides a continuity schedule for this deferral account.

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 Yukon Energy 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".*

Further to that direction, Yukon Energy provided a business case for its diesel rental costs in Section 3.3.2 and Appendix 3.1 of its 2023/24 GRA, and in its responses to various information requests in that proceeding (including, in particular, YUB-YEC-1-35 REVISED). The Board acknowledged this in Appendix A of Board Order 2024-05 (paragraph 133). While the Board expressed the view that Yukon Energy's business case "contained certain shortcoming" (paragraph 135), the Board was satisfied that Yukon Energy had proven that a capacity shortfall exists on the YIS unless additional capacity is added, and that, in the short term, the only solution was rental diesel units (paragraph 138).

In order to update the 2023/24 GRA diesel rental business case for the current GRA, Yukon Energy has considered the following possible alternatives to the proposed short-term rental of 22 diesel rental units for the purpose of meeting the N-1 dependable capacity criteria requirement during winter 2025/26, 2026/27 and 2027/28 as discussed in Section 2.4 of Tab 2.

Background - Yukon Energy Dependable Capacity Planning

As reviewed in Section 2.4 of Tab 2, Yukon Energy uses Loss of Load Expectation (LOLE) and N-1 criteria in capacity planning. To date, at the forecast industrial loads, the LOLE criterion was satisfied so long as the single contingency [N-1] criterion was met, which continues to be the case for the 2025-27 GRA. As indicated in that same section, without diesel rentals, the N-1 capacity criterion would not be met and there would be a significant capacity shortfall for the 2025-2027 test years. Therefore, Yukon Energy continues to rely on diesel rentals to close the dependable capacity gap to protect Yukoners' welfare, health and safety during emergencies.

This reliance is illustrated, for example, by the following three occurrences, when Yukon Energy has been able to maintain uninterrupted power supply to Yukoners by using the dependable backup capacity of its diesel rental units:

- The temporary failure of some generation units during a period of extreme cold weather on December 19 and 20, 2022, as reported in response to YUB-YEC-1-35 REVISED, Follow-up Question #3 in Yukon Energy's 2023/24 GRA.

- The plant outage experienced at the Aishihik Generating Station on January 31, 2024, as reported in Yukon Energy's February 8, 2024 rebuttal evidence in the 2023/24 GRA (Exhibit 9). Power supply to Yukoners was uninterrupted on that occasion due to dependable capacity backup of the diesel rentals while Yukon Energy staff worked to safely bring other resources online focussing on grid stability.

- On October 27, 2024, Aishihik Generator #1 went out of service due to an equipment failure, and that unit remains out of service at the time of GRA submission. Since the time of that equipment failure, Yukon Energy has been able to call on the diesel rentals to provide dependable power throughout the winter of 2024/25.

Overall, the diesel rentals first emerged in winter of 2017/18 as the only identified feasible way to address forecast dependable capacity shortfalls on a short-term basis to meet N-1 dependable capacity requirements. Subsequent Yukon Energy planning up to and including the current GRA did not identify diesel rentals as something to be proposed on its own as a long-term dependable capacity resource option. Rather, Yukon Energy's diesel rental implementation from the winter of 2017/18 up to the current GRA has been informed cumulatively by all of Yukon Energy's resource option analysis relating to the assessment, selection, development and commissioning of permanent dependable capacity resource options. In that context, Yukon Energy has considered diesel rentals as a residual option and a short-term solution, to the extent that the combination of other feasible options to be implemented by Yukon Energy would be insufficient to meet dependable capacity shortfalls without being supplemented by diesel rentals.

Prior regulatory proceedings, including the Battery Energy Storage System (BESS), the Atlin EPA (Electricity Purchase Agreement) and earlier GRAs provided significant details on Yukon Energy resource planning activities to address the capacity shortfall.

During the period after 2017-18, Yukon Energy's plans for a long-term option to address dependable capacity shortfalls evolved, and Yukon Energy's initial plan to proceed with the 20 MW diesel plant proposal as originally contemplated in the 2016 Resource Plan was cancelled and later replaced with the alternative plans described in the 10-Year Renewable Electricity Plan (10-Year Plan), which was completed in 2020 as a response to the Yukon's Our Clean Energy Future, a key policy climate change initiative, focusing on renewable options which included the planned development of the Moon Lake pump storage hydro project within less than 10 years.

At the time of the 10-Year Renewable Electricity Plan, Moon Lake pump storage was seen as a generational opportunity for Yukon to invest in a critical renewable electricity project which was intended as a long-term renewable solution, along with other long-term options of the 10-Year Plan [such as the Atlin EPA], would provide sufficient forecast dependable capacity to avoid any long-term requirement for diesel rentals or new large permanent diesel plants.

Under the 10-Year Plan, it was expected that use of rented diesels prior to commissioning of Moon Lake pump storage would avoid the need for Yukon Energy to incur capital costs to develop additional short-term diesel units that would cease to be used and useful as soon as Moon Lake pump storage became operational and thereby become stranded assets. Instead, the plan proposed capital spending on long-term generation and DSM resource options that would continue to be used and useful after Moon Lake pump storage became operational. In that context, it did not appear to be necessary to give specific consideration to other short-term options as an alternative to rental diesel for the period prior to Moon Lake's planned implementation and Yukon Energy's continued reliance on diesel rentals to close the dependable capacity gap.

As the YUB noted previously in Appendix A to Board Order 2024-05, paragraph 121, Yukon Energy acknowledged during the 2023/24 GRA proceeding that the BESS project had been delayed from its original forecast operation date (2022), that the Moon Lake Storage Project is currently not feasible to move forward in the foreseeable future, and that the likelihood of proceeding with the Atlin EPA is now in question.

Yukon Energy Updated Resource Planning

Yukon Energy has continued to develop new permanent capacity to address forecast dependable capacity shortfalls – and it is no longer relying on Moon Lake pump storage as a planned resource to provide new dependable capacity. As reviewed in Tab 2, Section 2.4, and in the business case for the Thermal Replacement Project in Appendix 5.1A, permanent dependable capacity forecast increases before the end of 2027 (and not included in the GRA test year approved rate base for 2024) include 11.5 MW new diesel (including diesel replacement) in Whitehorse and in Dawson (before winter 2025/26), as well as the addition of the BESS (5.5 MW) and incremental DSM (0.25 MW).

During its 2023/24 GRA, Yukon Energy provided information on its long-term objective to reduce or eliminate the continued need for mobile diesel rental units through its planned development of new permanent dependable capacity and noted that it was developing an Electricity Supply Plan for capacity solutions in the next 5 to 10-years as well as working on a longer-term Resource Plan.[1]

On April 8, 2025, Yukon Energy released two new electricity supply plan documents: *Building a Resilient and Renewable Energy Future: Yukon Energy's Road Map to 2050* and *Chapter 1: A Reliable and Robust Grid 2025-2030*, a five-year strategic plan.

As a pathway to a net-zero by 2050, Yukon Energy's new plans have identified a three-phase pathway: (1) Building a reliable and robust grid; (2) Creating a modern and flexible grid; and (3) Transitioning to a resilient and clean grid.

The Short-Term Actions focusing on 2025-2035, as part of the upcoming Resource Plan, identifies plans to build a reliable and robust grid over the next five years. The goal is to increase the reliability and stability of the grid such that intermittent renewables can be integrated without impacting grid stability as a pathway towards net-zero.

As discussed in Section 2.4 of Tab 2, in 2025 the forecast dependable capacity shortfall for serving non-industrial loads on the YIS is 34 MW. By 2035, this shortfall in dependable capacity needed is expected to grow to about 60 MW, 45 MW needed in the south region and 15 MW needed in the north region. In a high growth scenario, the capacity shortfall by 2035 is forecasted to grow up to 55 MW in the south region and 20 MW in the north region, totaling to a shortfall of 75 MW.

Experience to date confirms that the development of new permanent capacity takes time. In particular, any large new projects require prudent planning, and such projects are typically dependent on securing permitting and local First Nation support, as well as any necessary funding commitments from government, when applicable. Renewable energy projects that also provide dependable winter capacity are limited and often face added challenges.

In order to ensure reliable and timely development of the needed new permanent capacity, Yukon Energy proposes to fill this growing shortfall in dependable capacity with new thermal generation. The new thermal resources are the fastest and most reliable option to replace the capacity provided by the rental diesel generating units, meet on a timely basis the increased demands from load growth, and provide reliable backup capacity for proposed renewable resources. Please see Appendix 5.4A in Tab 5 which

[1] Reported on in Appendix A of Board Order 2024-05, paragraph 122.

discusses the new permanent thermal plant, Whitehorse Power Expansion Project, and capital plans to develop new thermal capacity for planned in-service before winter of 2029/30. Amongst other things, Appendix 5.4A provides evidence regarding the timelines expected to be required to develop this new permanent thermal capacity, as directed by the Board in Appendix A of Board Order 2024-05, paragraph 136.

In summary, the committed plan to provide major new thermal capacity as soon as feasible cannot provide new thermal during the current GRA test years. Therefore, diesel rentals remain the only viable option for 2025, 2026 and 2027 to close the dependable capacity shortfall. Accordingly, the revenue requirements for the 2025, 2026 and 2027 test years include the rental cost for 22 diesel units as discussed in Tab 2, Section 2.4.

During the review of its 2021 GRA, Yukon Energy 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 Yukon Energy. This was iterated in the 2023/24 GRA, and it remains the case for this GRA. However, Yukon Energy is exploring options to purchase a small number of units to use them as mobile units to support the system. This was discussed in Tab 3, Section 3.3.2 and does not impact the current GRA as the discussions are still at the early stages.

Yukon Energy is also able to provide the following updates on the current permitting status of its diesel units, including its efforts to achieve the objective previously described in Yukon Energy's February 8, 2024 rebuttal evidence in the 2023/24 GRA (Exhibit 9) of bringing the emergency operation of its diesel units within its permitted capacity for authorized operations under normal conditions (i.e., not restricted to emergency conditions), as requested by Environment Yukon:

- Air Emissions Permit No. 60-010-04, effective January 1, 2025 until December 31, 2034, now authorizes a maximum production capacity of 42.0 MW from thermal generation in Whitehorse under normal operating conditions (i.e., not restricted to emergency conditions).[2]

- New thermal generation in Callison is now fully permitted and operational.

[2] The YESAA submission for the Whitehorse Air Emissions Permit Renewal assumed seven diesel rental units in Whitehorse [seven units at 1.8 MW each for a total of 12.6 MW], assuming two new permanent units would replace the need for three diesel rentals. However, as noted in Section 2.4 of Tab 2, starting in winter 2024/25 for this GRA, Yukon Energy has adopted a more conservative approach for determining the winter dependable capacity of its generation resources to reflect effective load carrying capacity (ELCC). Therefore, Yukon Energy determined that the three diesel rentals are still required to close the capacity shortfall. Applying that more conservative approach, the total thermal dependable capacity for the 2025/26-2027/28 years for Whitehorse is 42.3 MW under an N-1 emergency event, as reviewed in Tab 2, Section 2.4; however, the operation of the thermal units under normal operating conditions will not exceed 42 MW, consistent with the permit requirements.

- Renewed air emission permits have been issued both for downtown Dawson (YESAB file no. 2024-0093) and for downtown Mayo (YESAB file no. 2024-0094).

- The Mayo Designated Office of YESAB has completed its assessment of the Mayo Secondary Thermal Capacity Expansion project (YESAB file no. 2024-0177) to increase permitted thermal generating capacity at Mayo Secondary from 4.8 MW to 9 MW, and issued an evaluation report on April 17, 2025 recommending that the project be allowed to proceed, subject to a requirement for Yukon Energy to develop an air quality management plan.

- The Watson Lake Designated Office of YESAB is in the process of completing its evaluation of the Faro Generating Station Capacity Expansion project (YESAB file no. 2024-0145) to increase the permitted thermal generating capacity in Faro from 15.5 MW to 20.4 MW, and Yukon Energy is in currently the process of responding to information requests as part of that evaluation.[3]

Consistent with the YUB's statement at paragraph 137 of Appendix A of Board Order 2024-05 that "[i]t is incumbent upon YEC to ensure it has all required regulatory approvals, processes, and assets in place to provide … safe and reliable service", Yukon Energy continues to work diligently towards obtaining approval for the amendments it is seeking to its air emission permits in both the Mayo Secondary Thermal Capacity Expansion project and the Faro Generating Station Capacity Expansion project. In the meantime, however, it continues to be Yukon Energy's evidence that it can and will operate any of its diesel rental units if and when it may become necessary to do so to protect the welfare, health and safety of Yukoners during an emergency, consistent with Yukon Energy's overarching statutory duty under section 106 of the *Public Utilities Act* to provide service to customers.[4]

[3] The 2023/24 GRA, based on information then available, assumed 20.6 MW of dependable diesel capacity at Faro, which included 8 MW from permanent units (assuming FD8 and FD9 would be operational before end of 2024) and 12.6 MW from rental units. Subsequently, the new diesel units FD8 and FD9 experienced delays, and they did not become operational until 2025. In October 2025, Yukon Energy also plans to complete site transformation upgrades in Faro (S140 5kV bus upgrade) to remove constraints on operating the available added capacity. As explained in Tab 2 (Section 2.4), the updated N-1 dependable capacity for 2025/26 winter and subsequent test years with FOR reductions of diesel winter dependable capacity assumes a total dependable capacity of 18.672 MW for the Faro Generating Station (7.962 MW from owned units and 10.71 MW from rented diesels). Yukon Energyis in the process of applying for a 4.9 MW increase in its permitted capacity in Faro, which will result in total permitted capacity of 20.4 MW from all thermal generation at that site. It may be technically possible to operate Faro thermal facilities up to a total of 20.6 MW; however, Yukon Energy chose to apply for a 4.9 MW increase at this time to facilitate timely and cost-effective regulatory review via a YESAB Designated Office evaluation – under the circumstances noted, the significant additional cost and delay of an Executive Committee screening for a 5.1 MW expansion of Yukon Energy's permitted capacity would not be of benefit to Yukoners and would be unwarranted at this time.

[4] See Yukon Energy's February 8, 2024 rebuttal evidence in the 2023/24 GRA (Exhibit 9); Board Order 2024-05, Appendix A, paragraph 126.

Summary Update Overview of Diesel Rental and New Permanent Diesel Costs

The updated Levelized Cost of Capacity (LCOC) analysis for diesel rentals as compared to the permanent diesel option is prepared for long-term, over 40 years based on the life of diesel engines, as well as for short-term focusing on the next 10 years.

The diesel rental costs are based on the contract price for the 2024/25 winter. It should be noted that Yukon Energy is in the procurement process for a multi-year rental contract for rental diesel generators beginning in the 2025/26 winter season. The multi-year contract will provide more certainty of availability and price certainty than with our existing 1-year contract. Therefore, the rental costs are assumed to increase by 2%/year over 2024/25 contract prices as compared to the 4% assumed in the previous GRAs.

The following summaries are noted on the LCOC for diesel rentals compared to the permanent diesel option:

- The LCOC over a 40-year life for the 16.5 MW Thermal Replacement Project at $228.8 per kW-yr (2025$) compares to the LCOC of $207.6 per kW-yr for 2025 rental diesel cost for all diesel rental units with 2%/year increase in diesel rental cost, and LCOC of $239.6-$279.4 per kW-yr with 3%-4%/year increase in diesel rental cost (assuming a 40-year life and excluding rental capital infrastructure costs).[5]

- The LCOC for the diesel rental units over a 10-year life is $207.6 per kW-yr with 2%/year rental cost increase, $216.3 per kW-yr with 3%/year rental cost increase and $225.4 per kW-yr with 4%/year rental cost increase.[6]

The analysis confirms longer-term cost savings from permanent plants compared with rental diesels if the diesel rental costs increase more than 2%/year, while also showing that short-term diesel rental costs (e.g., 10-years) are likely to remain competitive. In summary, before considering the fact that new permanent diesel unit costs will tend to be highest in initial operating years (before rate base costs are depreciated), the LCOC analysis over relevant longer term time periods shows that the current need to

[5] LCOC assessed assuming total rental cost of $6.9 million for 22 units to total of about 34 MW [with 15% Forced Outage Rates (FOR)]. The rental cost is assumed to increase 2%/year, sensitivity cases are included for 3% and 4%/year rental cost increases. The LCOC for the 16.5 MW thermal replacement project is based on the total cost of $62.2 million. Yukon Energy WACC for new rate base of 6.390%/year per 2025-27 GRA (60% new debt financed at 4.55% and 40% equity financed at 9.15% per the current Application). This comparative cost analysis does address net benefits from new, more environmentally friendly, likely lower operating cost Tier 4 new permanent diesel units compared to the Tier 2 rental units (Appendix A to Board Order 2024-05, paragraph 135, noted this limitation to this analysis).
[6] LCOC assessments are based on the same assumption as for the 40-year, except for a 10-year period.

rely on diesel rentals for the 2025-27 GRA test years is not expected to impose any cost penalty for Yukon Energy or ratepayers compared to what would have been needed with new permanent diesel units during these same test years.

APPENDIX 3.2
EMPLOYEE COMPLEMENT ADDITION JUSTIFICATIONS

APPENDIX 3.2: EMPLOYEE COMPLEMENT ADDITION JUSTIFICATIONS

This Appendix provides details regarding Yukon Energy's planned employee complement additions over the GRA test years (2025 to 2027). Yukon Energy acknowledges that forecasting staffing for future years is challenging as priorities can change rapidly. In an effort to minimize rate impacts, Yukon Energy has limited the number of additions. The forecast revenue requirements include the labour costs for the number of new positions.

Yukon Energy has forecast eight positions added for 2025, eight positions added for 2026, and at least five positions added for 2027. As time progresses, Yukon Energy may determine that positions, other than those listed here, may become needed as demands on the electricity system continue to grow. Yukon Energy can provide updates to the Board later in the 2025-2027 process.

The employee complement addition justifications are listed below and categorized first by year of addition and then by department.

3.2A-1: 2025 ADDITIONS

Additions planned for 2025 are summarized in the table below. The key focus is safety and reliability.

Table 3.2A-1: Summary of 2025 Planned Additions

Department	Title
Planning, Environment, Health & Safety	• Resource Planner
	• Training Coordinator
Operations	• Maintenance Engineer – Mechanical
	• Maintenance Engineer – Electrical
	• Electrical Technologist
	• Operation Technology (OT) Network and Automation Specialist
	• Financial Analyst
	• System Control Centre (SCC) Operator and Coach

3.2A-1.1: Planning, Environment, Health & Safety

Resource Planner

The Resource Planning group has one Resource Planner. The Resource Planner position plays a vital role across the organization including generation dispatch, water management, and resource planning modeling for generation planning. These three skillsets are critical to the function of the organization and without them, Yukon Energy is at risk of losing these competencies and increasing costs to outsource these needs. Without redundancy in these skillsets, the single Resource Planner has enormous pressure to conduct both important, and often urgent, analysis with very short turn-around timelines. This has led to overtime, stress, and the Resource Planner not taking vacation. Without redundancy in these skillsets, Yukon Energy lacks quality control of engineering work/analysis that is the basis for important decision making.

An addition of a Resource Planner in 2025 is considered necessary for many reasons, including:

- Provide redundancy and reduce risk; and
- Improve quality of deliverables.

Redundancy in this position is intended to provide as a critical back-up to Yukon Energy's only Resource Planner, allow for quality control activities, and improve deliverable timelines and overall quality of the work. This will effectively reduce risk to Yukon Energy and ratepayers. Secondly, Resource Planning activities that are important, but not urgent, are falling behind because there is too much workload for one Resource Planner Full Time Equivalent (FTE). By hiring a second Resource Planner, Yukon Energy will have capacity to update models and perform regular resource planning activities (such as update load forecasts and Integrated Resource Plans (IRPs)) regularly, increasing reliability and accuracy of the resource plan.

This position will address the strategic priority of *Invest in people* with the action to attract, develop and retain talent. This position will also address the strategic priority of *Plan the renewables of tomorrow*.

Posting of this position is planned for summer 2025.

Training Coordinator

The development and delivery of training in Yukon Energy is currently being done using a combination of in-house, contractor and third-party virtual and in-person trainers and training methods. The current situation is creating bottlenecks as well as being costly. Relying on contractors to deliver training puts

Yukon Energy at the mercy of the contractor schedule and availability. An example of this is the Substation level 2 training which is a requirement for switching on the system. It costs over $20,000 to deliver it because the contractor must come to the Yukon for a week. This means it is only being offered once per year, and employees who have had or receive the training that year are required to complete all substation switching tasks for the year which leads to inefficient job planning.

A new position in 2025 of a Training Coordinator is essential for managing and enhancing employee competencies and developing effective training procedures. The new position will be responsible for monitoring and advancing the core competencies for employees that are required for their work. This is crucial for ensuring that our workforce remains skilled, safe, and capable of meeting organizational goals as new technologies (e.g., wind, solar and battery technologies) are integrated onto the Yukon grid. This role will also involve creating and implementing comprehensive safety training procedures and job aides. This will help standardize our safety training efforts and ensure all employees receive consistent and effective safety training. This position is a must-have to handle the significant task of managing employee competencies and ensuring employees are completing their work safely and returning to their families each night. Without this role, our ability to track and develop these competencies effectively will be compromised, potentially impacting our overall safety, and performance and productivity.

This role will also serve as the in-house expert to develop course material for Yukon Energy's Learning Management Software (LMS) system as well as deliver Health & Safety (H&S) training.

This position, while being part of the H&S department, would be of great benefit to all departments and the Corporation. Yukon Energy must often wait for external resources to complete training. This position could provide some in-house training on a more timely basis. This position would help with new employee onboarding and ensure new employees have completed their required onboarding and training as per the prescribed timelines. This position would also be responsible for the Technical/Operational competency program to ensure employees are matched only with tasks that they have demonstrated that they have the competency to complete. This is critical to maximizing employee safety.

This position will address the strategic priority of *Be an industry leader in safe work practices* with the specific action of continually strengthening our employee, public and facility safety programs.

At the time of preparation of this Application, Yukon Energy had posted the job and was in the process of interviewing potential candidates.

3.2A-1.2: Operations

Maintenance Engineer – Mechanical and a Maintenance Engineer – Electrical

Yukon Energy currently has an engineering team, but their capacity is almost fully utilized by the capital program and there is little time available to fix or resolve engineering issues stemming from our existing assets and day-to-day operations. The addition of a Maintenance Engineer – Mechanical and a Maintenance Engineer – Electrical in 2025 will give Yukon Energy's Operations department the engineering support it needs (e.g., identifying the root cause of a generation or transmission outage and engineering a solution to fix the problem and mitigate the risk of it happening again). Currently contractors are often required to complete Root Cause Analysis. These two positions will also provide the ability to review and analyse data and support better decision making for parts ordering and MOC[1] (Management of Change) processes.

An example of the current process is Operations performs a generator PM (Preventative Maintenance) on the WH4 hydro generator. The data is collected and stored electronically. While the report is reviewed by the Operations team, an engineer only reviews the report if an issue is identified. This can lead to over maintaining or undermaintaining of the asset and can lead to long-term issues forcing Yukon Energy to react to an emergency. Having these engineers would allow Yukon Energy to complete a full maintenance cycle and review of critical mechanical and electrical assets, and indicate what spending is appropriate.

These two Maintenance Engineer positions will also provide the necessary capacity required to support the safe and reliable operation of existing assets while also freeing up space for the existing Engineering team to focus more time on the design and delivery of new large capital projects.

These positions will address the strategic priority of *Investing in people and technology* with the specific action of continuing to build and utilize our asset management program to improve asset decision making and realize value from our assets. These positions will also address the strategic priority o*f Strengthening our electrical infrastructure* with the specific action of increasing the capacity and reliability of our transmission, distribution, and substations across the Yukon.

At the time of preparation of this Application, Yukon Energy had posted these two jobs and completed the process of interviewing potential candidates.

[1] MOC is a process put in place to ensure a proposed modification to a piece of equipment has been properly assessed, to ensure there are no negative consequences and to ensure all related work involved with a change is also completed, such as updating drawings or manuals.

It is expected that both of these positions will be filled in Spring 2025.

Electrical Technologist

There are currently three Technologists in the electrical department that all report to the Supervisor. Due to extremely high electrical workload, the supervisor also needs to manage an increasing number of external resources. There is limited capacity to do this, and the situation is leading to burn out and high levels of overtime in the department. Additional personnel is required to support the volume of work in this area.

The addition of a *Senior Electrical Technologist* in 2025 will support the development and management of the maintenance capital program. Additionally, technologists are the people that heavily support automation processes in the field. To advance an automation effort, consistent with our strategic plan, Yukon Energy needs to build skills in this area. Key roles and responsibilities of this position would include:

- Supervision and scheduling of internal and external technologists;
- Work order management; and
- Capital project development and support.

This position will also allow for structure and career progression of employees in the technologist group within Yukon Energy. It will address the strategic priority of *Investing in people and technology* with the specific action of continuing to build and utilize our asset management program to improve asset decision making and realize value from our assets. The electrical department has seen significant turnover, so this position will greatly assist the strategic priority of developing and retaining talent within the organization. This position will also address the strategic priority of *Strengthening our electrical infrastructure* with the specific action of increasing the capacity and reliability of our transmission, distribution, and substations across the Yukon.

This position was filled in February 2025.

Operational Technology (OT) Network and Automation Specialist

There is a need for Yukon Energy to increase its skills and understanding of its OT network as more generation, transmission and distribution assets are added to the electricity system and more systems are automated. At present time, Yukon Energy does not have a dedicated resource to manage the OT network.

Currently, these activities are being done by some individuals that work in the area but already have full-time roles and responsibilities.

The addition of an OT Network and Automation Specialist in 2025 is required to support growing demands on our OT network. Over the next few years Yukon Energy will be advancing and increasing a number of automation initiatives and will be adding a significant amount of new equipment to the system. Without someone to manage the network and be responsible for this OT network and associated functions, security and workload, this new equipment will be difficult to integrate and there will be security risks. This position would also support the development and management of maintenance for OT devices and critical communications equipment. Additionally, this program is key for supporting and integrating capital projects.

The OT Network and Automation Specialist will be responsible for overseeing and enhancing the operational technology systems within the utility, with a primary focus on Supervisory Control and Data Acquisition (SCADA), network infrastructure, communication devices, and automation systems. This role emphasizes securing OT systems and ensuring their integration, reliability, and efficiency. The position involves optimizing OT performance, developing automation strategies, and ensuring security and compliance with all operational technology. The OT Network and Automation Specialist works with all aspects of the Yukon Integrated System (YIS) and collaborates with personnel across many departments at Yukon Energy, as well as contractors.

An OT Network and Automation Specialist has a technical leadership role, driving operational continuity, OT cybersecurity, control system integration to SCADA, and remote engineering access to critical systems in plants and substations.

Key roles and responsibilities of this position would include:

- Oversight of SCADA, automation, security, and network operations within the OT domain;
- Resolve unplanned OT issues, including failures or disruptions in SCADA systems, AMI infrastructure, DSM technologies, and communication networks. Investigate root causes and develop corrective action plans to prevent recurrence;
- Create and implement maintenance and test plans for OT assets to ensure optimal performance and reliability;
- Recommend improvements to OT systems for performance optimization, security, and efficiency;

- Supervision and scheduling of internal and external workers;
- Work order management;
- Capital project development and support; and
- OT network maintenance and ownership.

The position will address the strategic priority of *Investing in people and technology* with the specific action of improving business processes with new and existing technologies. This position will also address the strategic priority of *Strengthening our electrical infrastructure* with the specific action of increasing the capacity and reliability of our transmission, distribution, and substations across the Yukon.

Posting of this position is planned for summer 2025.

Operations Financial Analyst

Operations staff are heavily engaged in the day-to-day of operating equipment and have difficulty in finding capacity to develop business cases, accurately forecasting resourcing needs, and ensuring process loops are closed. This position supports the Operations department in developing business cases, ensuring project and corporate processes are followed and that the proper documentation is produced. This position also supports the department in a number of areas including procurement of parts and services, visa processing, and data entry into the Enterprise Asset Management (EAM) system and other corporate systems.

This position allows Yukon Energy to better utilize the skills of trades staff to complete their designated roles as it centralizes a number of critical support services necessary to complete their projects and office-based duties. The Operations Financial Analyst will also support better decision-making by regularly tracking and analyzing costs and developing more accurate forecasts of both O&M and capital budgets in the Operations department. This position also helps Operations to better support Finance and other departments as forecasting of resource needs will improve. Reliability should also improve as data entry into the EAM asset management will get better and entered more quickly with this role.

Key roles and responsibilities of this position would include:

- Prepare and maintain financial reports and performance metrics for the Operations department;
- Analyze operational costs and identify cost-saving opportunities;

- Review financial data to ensure accuracy and compliance with company policies;
- Monitor financial performance against budgets and forecasts, highlighting discrepancies or variances;
- Providing financial data to support Business Cases and Board Reports;
- Assist in the preparation of annual budgets and periodic forecasts for the Operations team;
- Collaborate with department supervisors to evaluate financial needs and set realistic goals;
- Track budget performance and assist in the development of corrective actions as needed;
- Analyze key operational metrics and financial indicators to assess efficiency and performance;
- Provide actionable recommendations to optimize operations based on financial and performance data;
- Support continuous improvement initiatives by identifying areas for cost reduction and process optimization;
- Monitor and analyze operational costs, including labour, materials, overhead, and supply chain expenditures;
- Assist in evaluating financial aspects of vendor contracts, procurement, and supply chain management;
- Support cost allocation processes and ensure proper allocation of expenses to the appropriate departments, workorders or projects;
- Conduct variance analysis to identify cost overruns and work with teams to implement corrective actions;
- Track and monitor thermal fuel inventory and costs;
- Develop financial models to support decision-making processes;
- Forecast future financial performance based on historical data, trends, and assumptions; and

- Provide recommendations on pricing, and resource allocation based on financial models.

Posting of this position is planned for spring 2025.

System Control Centre (SCC) Operator and Coach

The SCC group is an area in which contracting out work is either very difficult or not possible. Given this fact, turnover and leave have an outsized impact on the group and lead to excessive amounts of overtime and worker burn out. Additionally, Operators take six to eight weeks to become desk qualified and in the current environment it takes many years to become competent with all the skills needed to run the power system. The group of existing SCC Operators are currently very new with very little seniority in the team. This means there are only a couple of team members that can provide support when tasks become complex.

This position is needed to add capacity to the group. This position would be able to support all functions in the SCC department including the ability to operate the system, perform SCADA activities, data reporting and permit review. Additionally, this position will be responsible for running the power system simulator and training the operator group. Currently training of this group is very difficult and there is little in the way of formal competency checks and programing.

This position was filled in December 2024.

3.2A-2: 2026 ADDITIONS

Additions planned for 2026 are summarized in the following list.

Table 3.2A-2: Summary of 2025 Planned Additions

Department	Title
Partnerships & Business Services	• Infrastructure Coordinator
	• People & Culture Generalist
Finance, Procurement & Warehouse	• Manager, Warehouse & Materials Management
Operations	• Apprentice Power Line Technician
Resource Planning	• Permitting and Monitoring Coordinator
Engineering	• Junior Draftsperson
	• Project Coordinator
	• Electrical Engineer

3.2A-2.1: Partnerships & Business Services

Infrastructure Coordinator

Yukon Energy's Information Technology (IT)/OT system is growing with the addition of servers, substations, assets (the battery and thermal) and IPP sites, and will continue to grow in the interim as grid modernization strategies are implemented (e.g., Automated Metering Infrastructure (AMI)). IT/OT network links need to be established, maintained, trouble-shot and protected. This work is critical also so that Yukon Energy can automate services to each of these sites (i.e., avoiding people going out to visiting sites or travel to communities to collect data logs, reports, etc.).

Without an employee dedicated to bolstering and supporting the safe and secure integration of IT/OT infrastructure, Yukon Energy currently relies on an external contractor to perform the required tasks. In less than a week, Yukon Energy can spend nearly $100,000 in contracting fees for this specialized type of work. This money can otherwise be spent on a full-time employee who is available year-round. The addition of an Infrastructure Coordinator would achieve that objective. Key roles and responsibilities of this position would include:

- Collaborating with stakeholders, including internal business units and external vendors, to define project requirements, objectives, and timelines for IT/OT infrastructure projects;

- Develop project plans, schedules, and resources allocation strategies to ensure successful execution of IT/OT infrastructure projects;

- Manage deployment and implementation of IT infrastructure solutions, including hardware, software, and network components;

- Coordinate with internal teams and external partners to procure equipment, configure systems, and execute deployment activities according to project specifications;

- Identify potential risks and compliance requirements associated with infrastructure projects such as security vulnerability, regulatory standards, and data protection measures;

- Develop risk mitigation strategies, contingency plans, and compliance frameworks to ensure project success and adherence to organizations policies;

- Coordinate vendor relationships, including vendor selection, contract negotiation, and performance evaluation;

- Manage procurement processes, including drafting requests for proposals, assessing proposals, submitting requisitions for purchase orders, and reviewing invoices prior to payment, to ensure timely delivery of goods and services within budgetary constraints and procurement guidelines;

- Maintain accurate documents, including project plans, technical specification, and implementation guides, to support infrastructure projects and operations; and

- Generate progress reports, status updates, and post-implementation reviews to communication project milestones, achievements and lessons learned to stakeholders.

This position will address the strategic priority of *Invest in people and technology* with the specific action of improving business processes with new and existing technologies. It will also address the strategic priority of *Strengthen our electrical infrastructure to adapt to evolving customer needs* with the specific action of increasing the reliability of our transmission, distribution, substations, and network communications to deliver electricity across the Yukon.

This position would work closely with the OT Network and Automation Specialist hired in 2025 but will have separate duties and responsibilities. Below is a high-level overview of the differences between the two positions.

Table 3.2A-3: Summary of Key Differences

Infrastructure Coordinator	OT Network and Automation Specialist
• Project and vendor coordination role; more focused on ensuring infrastructure readiness.	• Technical leadership and systems expert in OT/SCADA/security.
• Supports IT/OT infrastructure deployment but does not own the systems.	• Owns and operates OT systems and ensures their reliability and security.
• Acts as a project delivery enabler, handling infrastructure rollouts, vendor logistics, and cross-functional planning.	• Leads technical decisions, system-level integrity, and OT security. Needs visibility and decision-making authority within operations.
• Limited supervisory duties.	• Supervises a team and leads technical governance.

People & Culture Generalist

Currently, the People & Culture (P&C) department is struggling to keep up with the growth of Yukon Energy. The department only has two positions (Manager, P&C and P&C Generalist) that serve an employee complement of 124 employees (62 employees per 1 Human Resources (HR) staff). With Yukon Energy's employee complement scheduled to increase by approximately 25 FTEs from 2025-2027, this would make the work tasks for the department unattainable. The department is currently at the point of being unable to provide timely resolution to employee requests and needs. Any increase to other company positions will need to be reflected by an increase to the P&C department.

When the P&C department becomes overwhelmed, it can lead to several risks that affect not only P&C itself but also the entire organization. Below are some of the key risks:

- Poor employee experience;
- Risks of non-compliance with codes, labour agreements and company policies;
- Ineffective recruitment;
- High employee turnover;
- Limited employee development;
- Decreased productivity;
- Employee relations issues;
- Strain on leadership and management;
- Decreased organizational agility; and
- Inability to foster a positive culture.

Key roles and responsibilities of this position would include working in a team-based environment and performing a range of administrative and human resources activities in areas such as recruitment, employee benefits, salary and benefit administration, collective bargaining, job classification and training and development.

This position will address the strategic priority of *Invest in people and technology* with the specific action of attracting, developing, and retaining talent.

Posting of this position is planned for Spring 2026 with an expected start date of July 1, 2026[2].

3.2A-2.2: Finance, Procurement & Warehouse

Manager, Warehouse/Materials Management

The warehouse management function within Yukon Energy has often been viewed as a secondary responsibility for managers juggling multiple priorities within their portfolios. In recent years, it has been integrated under departments such as procurement, risk management, and facilities management. It is currently managed by the Manager, Procurement. As a result, the warehousing function has remained underdeveloped, lacking a clear mandate, and fully realized operational maturity.

A full-time warehouse manager would ensure efficient operations and maintain high levels of organization and productivity with warehousing strategies, plans, and tasks. Yukon Energy is looking to expand the warehousing function to include Generation assets (not just Transmission and Distribution (T&D) assets). This is needed now more than ever due to the planned addition of parts for new projects such as Thermal Replacement and the Battery Energy Storage System (BESS), and specialized nature of generation equipment which tends to make them a long lead item to procure. The addition of a Warehouse Manager also provides opportunities for closer integration of Yukon Energy's EAM system and warehousing of parts and critical spares.

The warehouse is a critical hub for storage, handling, and distribution, and having a dedicated manager ensures accurate inventory management, reducing the risk of stockouts or misplaced items. A full-time manager would oversee day-to-day operations, address issues in real-time, and implement systems to improve efficiency, such as optimizing storage layouts and managing shipments. This would prevent delays, enhance customer satisfaction, and maximize workplace safety, fostering a motivated, organized workforce.

Key roles and responsibilities of this position would include:

- Warehouse organization and safety;

[2] Table 3.4 reflects a 0.5 FTE increase in 2026 and a further 0.5 increase in 2027 for a total addition from the 2024 GRA of 1.0 FTEs.

- Team and logistics management;
- Data reporting and budgeting; and
- Quality and process improvement.

This position will address the strategic priority of *Invest in people and technology* with the specific action of continue to build and utilize our asset management program to improve asset decision making and realize value from our assets. It will also address the strategic priority of *Be an industry leader in safe work practices* with the specific action of continually strengthening our employee, public and facility safety programs.

Posting of this position is planned for Fall 2025.

3.2A-2.3: Operations

Apprentice Power Line Technician (PLT)

The PLT department has experienced a high volume of overtime. PLTs also have a high volume of standby (e.g., being available for work after regularly scheduled hours to respond to outages and other emergencies), which leads to staff burn out and increased costs. This has left the department with not enough staff for an extended period and has led to an increase in contractors filling the gap and at times, supplementing the Yukon Energy line crew. An Apprentice PLT position combined with others will help reduce overtime costs on an individual basis.

Benefits of this position include:

- Ensure that Yukon Energy has adequate staff to perform typical day-to-day tasks;
- Improve safety by reducing the requirement for PLTs to work alone;
- Create a position that grows new workers for company growth and future succession;
    - The skills of a PLT are transferable to other departments within Yukon Energy. Yukon Energy has had multiple past experiences where PLT apprentices have become qualified (Apprenticeship completion) and go on to fill other critical gaps at Yukon Energy in the system control centre, and operational supervisory and management roles; and

  - These workers have in most cases become long-term employees.

- This allows us to hire and develop Yukon citizens that typically seek long-term employment in the territory; and

- Demand for skilled workers has increased broadly across industry. This is due to growth in electrification and a result of a generations of workers retiring. In order to fill this gap, Yukon Energy needs to have a well establish apprenticeship program to grow and develop qualified workers.

Key roles and responsibilities of this position would include:

- Support PLTs in their day-to-day work such as:
  - Maintenance;
  - Construction; and
  - Customer service.
- Drive and operate all types of heavy equipment; and
- Perform line audits and asset inspections.

Posting of this position is planned for Fall 2025.

3.2A-2.4: Resource Planning

Permitting and Monitoring Coordinator

By the end of 2027, all of Yukon Energy's existing hydro, liquefied natural gas and diesel facilities are expected to be re-permitted or re-licensed, allowing for the ongoing operation of these facilities. As part of these recent and ongoing processes, regulators such as the Yukon Water Board, Department of Fisheries and Oceans Canada, and Yukon Environment have significantly increased the number of terms and conditions that Yukon Energy must comply with in order to continue to operate these facilities. These terms and conditions include, but are not limited to: developing, implementing, and regularly updating modern-day Monitoring and Adaptative Management Plans (MAMPs) for Yukon Energy's hydro facilities together in collaboration with First Nation governments in the facility's project area; installing and monitoring air quality at specific thermal sites; and tracking noise complaints from certain facilities as well. The level of work that is required to abide by all these terms and conditions exceeds the capacity of Yukon Energy's existing resources. The addition of the Permitting and Monitoring Coordinator will be responsible for ensuring regulatory terms and conditions for each of the Yukon Energy's existing facilities are fulfilled. Today, contractors support Yukon Energy in this area of work. This position would directly offset the need for at least one full-time contractor who is presently working on these tasks for the Whitehorse Rapids Generating Station.

Key roles and responsibilities of this position would include:

- Tracking the regulatory terms and conditions of all existing facilities;
- Liaise with First Nation governments, territorial and federal governments, and appropriate regulators to develop plans to meet regulatory requirements, and to develop reports on annual activities completed to fulfill the requirements;
- Plan, budget and track expenditures of each facility's monitoring and adaptative management plan and permitting requirements;
- Write business cases, develop and review Requests for Proposals (RFPs), and manage contracts with suppliers and goods and services required to be compliant with regulatory terms and conditions; and
- Liaise with departments across Yukon Energy to inform employees of operating requirements and develop processes and procedures to ensure compliance.

Posting of this position is planned for Fall 2025.

3.2A-2.5: Engineering Services

Junior Draftsperson

Yukon Energy currently has one draftsperson. The Draftsperson cannot keep up with the workload and there is no backup for this position. If the existing Draftsperson is away, work gets delayed. If the existing Draftsperson were to leave Yukon Energy, there is business continuity risk to both the Engineering and Operations teams.

This role would be responsible for maintaining T&D pole and structure data and coordination of land management and contractor activities. Workload in this area is increasing because of the large amount of current and planned capital projects. It has increased both the demand for modifying existing drawings (sometimes requiring redraw of old scanned files) and the addition of new drawings for both new capital projects and day-to-day operations work.

Every construction and site drawing that is modified or made by Yukon Energy must go through the Drafting department. The drawing lists are updated, and drawings binders and site copies are printed and distributed. All construction drawings are moved to the plant title block/system when they are completed so even when consultants are doing the design drawings (because of a shortage of current staff), they still require Yukon Energy drafting time/resources to be put in the system.

Most of the work currently for T&D is for the design and construction of new customer service connection, including drafting of construction drawings, easements, permitting etc., and then updating the distribution master drawings with the new customer information. As upgrades continue to be made to the distribution and transmission assets that Yukon Energy owns and operates (e.g., the Dawson Voltage Conversion Project) demands for these services and a full-time employee will continue to increase.

Key roles and responsibilities of a Junior Draftsperson position would include:

- Produce and update civil, structural, mechanical, and electrical engineering design and As Built drawings, including single line diagrams, schematics, distribution, structural and piping drawings using CADD technology;

- Manage and organize drawing master sets. Organize, maintain, improve, and expand the engineering drawing records and document control systems, manuals, and technical libraries;

- Manage and update equipment, pole and structure data records for T&D systems;

- Maintain files and records of land use activities and reports, and search and retrieve drawings and records as needed; and

- Ensure that all drafting equipment and plotters are always in good working condition.

This position will address the strategic priority *Invest in people* and technology with the specific action to attract, develop and retain talent and to continue to build and utilize our asset management program to improve asset decision making and realize value from our assets.

Posting of this position is planned for Fall 2025.

Project Coordinator

As Yukon Energy prepares to implement a new Project Management Information System (PMIS), the system requires an additional resource to make sure Yukon Energy is optimizing the program by generating the required reports to formulate business decisions, assist with merging existing capital projects, enter new projects, and develop onboarding/training materials. Yukon Energy intends to accomplish this by adding a Project Coordinator in 2026. This position will act as the PMIS champion to clarify any questions and support the team with the integration.

Key roles and responsibilities of this position would include:

- Project Planning and Scheduling:
  - Assist in creating project schedules, including task sequencing and resource allocation;
  - Monitor project progress and report any delays or issues to Senior Project Manager/Director; and
  - Support updating and maintaining project timelines and schedules as needed.
- Documentation, Record Keeping, and Reporting:
  - Maintain project files and documentation systems, which include project documentation, contracts, permits, drawings, and specifications;
  - Organize project-related files and documents for easy access;
  - Prepare and distribute meeting minutes and project reports;
  - Prepare regular progress reports and updates for senior management and clients; and
  - Assist in the preparation of project closeout documents and reports.

- Communication and Coordination:
  - Act as a liaison between various project stakeholders, including clients, contractors, subcontractors, and team members;
  - Schedule and coordinate project meetings, including site visits and progress reviews; and
  - Ensure timely and effective communication of project updates and changes.
- Resource Management:
  - Assist in tracking and managing project resources, such as labor, materials, and equipment;
  - Help in procurement activities, including obtaining quotes, receiving invoices, and tracking deliveries; and
  - Monitor and report resource utilization and costs.
- Budget Tracking and Cost Control:
  - Help in tracking project expenses and comparing them to the budget;
  - Identify cost-saving opportunities and report cost overruns to senior management; and
  - Assist in preparing financial reports and forecasts.
- Change Order Management:
  - Assist in processing and documenting change orders, including scope changes and cost adjustments.

This position will address the strategic priority *Invest in people* and technology with the specific action to improve business processes.

Posting of this position is planned for Fall 2025.

Electrical Engineer

Yukon Energy has one SCADA Engineer (Electrical Engineer) on 0.75 FTE. This individual is heavily loaded and cannot cover the SCADA, Automation, and Communication needs required for all our capital projects and scheduled and emergency O&M needs. About 70-80% of capital projects have SCADA and Communications requirements to provide visibility, control, monitoring and event logging for all new generation, transmission and distribution assets connecting to the YIS. Yukon Energy is seeing more demand for the SCADA Engineer's time with ongoing Capital Projects and Operations and Maintenance (O&M) work orders. One individual can realistically support only three to four large projects in a fiscal year and O&M emergencies.

Yukon Energy is currently procuring the services of external consultants to supplement the needs of this role, and this has been a costly endeavour. External consultants are currently being engaged to support SCADA and communication system integration for new generation, transmission, and distribution assets connected to the YIS. Due to limited internal capacity, consultants are also being used to address urgent SCADA or communication system failures that affect utility visibility and control of the electricity system. In addition to costs, Yukon Energy's experience in getting dedicated consultants to serve this purpose has been unsuccessful. For example, within six months in 2023, Yukon Energy lost two external consultants to other employers after spending a lot of time bringing them up to speed to support ongoing capital projects. Reliance on external contractors continues to pose risks in terms of continuity and ownership. Internalizing this capacity will improve continuity, reduce long-term costs, and build institutional knowledge in managing Yukon Energy's specialized SCADA and automation systems.

This position is needed to deliver high-priority capital projects (mechanical, electrical and T&D), support operations, planning and contribute to improving safety and reliability. Yukon Energy will continue to rely heavily on consultants to deliver capital projects, but the Engineering team requires people who will take ownership and knowledge of the work being delivered for the ongoing support of the operation and maintenance of that asset. SCADA Engineering is a specialized niche and company-specific; if reviews cannot be completed on time, this often results in rework on projects with additional costs.

Some key projects that this position will support over the next five years include:

- WH1 Hydro Unit Uprate;
- Ongoing Plant and Substation Protection, Controls and SCADA upgrades;
- Transformer and reactor replacement projects;

- Grid Modernization;
- IT/OT network segregation project;
- Wareham Dam Spillway Project;
- MH0 Plant future upgrade planning;
- Governor Upgrades to Hydro Units;
- Fire protection system upgrades;
- New thermal projects;
- New wind and BESS projects;
- Balance of Plant upgrades; and
- Instrumentation and monitoring of critical dam infrastructures.

Posting of this position is planned for Fall 2025.

3.2A-3: 2027 ADDITIONS

Additions planned for 2027 at this time are summarized in the following list.

Table 3.2A-4: Summary of 2027 Planned Additions

Department	Title
President & Corporate Services	• Office Assistant
Partnerships & Business Services	• Director of Business Services
Operations	• EAM IT Systems Support
	• Electrical Job Planner
Engineering	• Transmission and Distribution Engineer-in-Training (EIT)

3.2A-3.1: President & Corporate Services

Office Assistant

Yukon Energy currently lacks administrative support to perform critical tasks such as record-keeping and basic book-keeping. While the Engineering and Capital Projects, and Operations departments, along with the Corporate Secretary have departmental administrators, they are often overloaded with the increased volume of record-keeping, book-keeping and requests for support from employees and management that have resulted from an increased volume of capital and operational projects and expenditures, and Yukon Energy's increased workforce. There has been a noticeable lag in the completion of daily tasks across various departments such as the timely submission of expenses reports, review and processing of invoices, record-keeping and tracking of regulatory requirements and submissions. This delay is impacting overall productivity as field staff, senior managers and executive are taken away from priorities to complete these tasks. Existing assistants are experiencing significant burnout due to the high workload demands. This not only affects employee well-being but also reduces efficiency and job satisfaction. Outsourcing certain tasks has been considered; however, it would result in higher costs, which is not a sustainable solution in the long-term.

All departments have expressed a need for administrative support. Addition of an Office Assistant will help reduce burnout and administrative burden of other staff who currently complete these tasks in addition to their full-time responsibilities. This position is critical to address several ongoing challenges and to enhance Yukon Energy's operational efficiency.

Key roles and responsibilities of this position would include:

- Maintaining and updating files and records that are required by regulators;
- Tracking and supporting staff in the timely submission of regulatory documents;
- Data entry;
- Sorting and distributing incoming mail and preparing outgoing mail;
- Assistance with printing, photocopying, and mailing documents;
- Organizing travel for individuals or teams;

- Handling basic bookkeeping tasks like invoicing and issuing cheques;
- Ensuring company records, including employee expenses, invoices, and purchase orders, are kept up to date;
- Preparing company letters or other official documents as instructed;
- Setting up meetings, organizing meeting logistics, and recording meeting minutes, as requested;
- Ensuring office and cafeteria supplies are stocked and ordered as needed for Yukon Energy offices across the Yukon;
- Maintaining company phone listing; and
- Supporting staff with company housing and vehicle bookings.

This position will address the strategic priority *Invest in people* and technology with the specific action to improve business processes and retain talent.

Posting of this position is planned for Fall 2026.

3.2A-3.2: Partnerships & Business Services

Director of Business Services

Building, supporting, and implementing the business services required to drive a business with a large annual capital program and plans for significant new generation requires the strategic direction and support of Director of Business Services to oversee the IT and P&C departments. Yukon Energy does not have a Chief Information Officer or Director of P&C. Currently, direct oversight, management and planning of IT and P&C is done by the Vice-President, Partnerships and Business Services who also leads the Partnerships, Communications and Community Engagement, and Customer Service departments and is responsible for corporate strategic planning, partnerships and policies, government relations and other executive levels responsibilities. The addition of this position would also allow for the potential synergies of bringing Health & Safety and Environment (HSE) into a larger Business Services team (currently part of the Resource Planning group).

Key roles and responsibilities of this position would include:

- Oversee the execution of critical information technology plans, and governance and cybersecurity policies and programs;
- Oversee the IT function, including infrastructure, security, vendor management, and digital transformation strategies;
- Develop long-term people and culture strategies to address short and long-term changes to the labour force and increased levels of health, safety, and environmental regulatory and compliance matters;
- Provide expert guidance and leadership on people-related matters, focusing on the enhancement and integration of HR systems, processes, and policies to improve efficiency and clarity across the organizations;
- Develop and implement robust People and Culture strategies and business metrics that bolster organizational goals around engagement, collaboration, and innovation, ensuring business objectives are effectively translated into clear, actionable HR tactics;
- Lead key initiatives that empower and engage employees, positioning Yukon Energy as an employer of choice by leveraging improved recognition mechanisms and fostering a supportive and collaborative work environment;
- Provide leadership to a newly forming team, promoting collaborative engagement, leadership development, and mentorship to support the broader strategic goals of the organization;
- Drive the transformation and modernization of People practices, integrating advanced technology, digital innovation, and forward-thinking strategies to foster strong partnerships;
- Participate in emergency response and business continuity planning, and ensure IT, People and Culture, health, safety, environment, and risk management practices are in place;
- Carry out analysis on complex resource management issues and initiatives that concern the organization;
- Prepare reports, correspondence, and submission to senior management; and

- Provide leadership, supervision, and mentorship to departmental staff.

This position will address the strategic priority of *Invest in people and technology* with the specific action of improving business processes with new and existing technologies. Addition of this position will relieve some pressure of the Vice-President, Partnerships and Business Services, allowing for more time to focus on other strategic priorities of *Grow and develop partnerships with Yukon First Nations, Plan the renewables of tomorrow* and *Build understanding of Yukon's electricity system and planning*. This position also provides opportunities for in-house succession opportunities for the Vice-President of Partnerships and Business Services role.

Posting of this position is planned for Fall 2026.

3.2A-3.3: Operations

Enterprise Asset Management (EAM) IT Systems Support

EAM integration and system support is currently being supplied through contractors. Relying on contractors for this support creates risk for Yukon Energy as the support is very specialized. The support also comes at a significant cost. If Yukon Energy were to develop this support in house, cost savings could be realized.

This position supports our initiative to advance our EAM program to help us make better data driven business decisions and to increase reliability. Custom integrations were developed to integrate our EAM software with other corporate programs. As new software is introduced into Yukon Energy, new integrations will need to be developed and maintained. This position will also work to ensure Yukon Energy is fully utilizing the EAM software.

Posting of this position is planned for Fall 2026.

Electrical Job Planner

Operations supervisors are heavily engaged in the day-to-day tasks of their groups and do not have the capacity to drive continuous improvement, improve efficiencies, coach staff, and ensure process loops are closed. The addition of an Electrical Job Planner would support the supervisor function in job planning and work scheduling. With the support of this position, jobs that require the same staff or need to be done in the same community can be done more efficiently, with less travel time if the projects are scheduled to follow each other, instead of weeks or months apart.

This position supports Yukon Energy's initiative to advance the EAM program to help make better data driven decisions. Yukon Energy currently has a Mechanical Job Planner supporting the mechanical side of operations. An Electrical Job Planner would ensure the required support is in place across both disciplines.

There are three primary areas where the Mechanical Job Planner position has increased efficiencies in the Maintenance Job Planning group and the Operations Department as a whole. It is expected that the hiring of an Electrical Job Planner would yield the same benefits for our electrical departments:

- Increasing the efficiency of the Mechanical, Plant Operator, and Property Management groups — both in their use of EAM and in aligning their work with Operations Department priorities. An Electrical Job Planner would allow this to occur in the OT and Electrical departments;

- Improving the EAM system itself — including both the quality of data being entered and the usefulness of the data being pulled from it; and

- Reducing the planning burden on Supervisors (particularly the Supervisor of Job Planning), allowing more time to focus on strategy, priorities, and cross-department coordination. Once EAM is optimized the planning positions would support all supervisors.

The Electrical group has more work orders than any other group by far. Done correctly, organizing, and managing them is itself a full-time job.

Posting of this position is planned for Fall 2026.

3.2A-3.4: Engineering Services

Transmission & Distribution (T&D) Engineer in Training (EIT)

As Yukon Energy begins to build up capacity within T&D Engineering, it has been apparent that a T&D EIT would help with supporting T&D design and engineering, preparing work packages, supporting Customer Connections, reviewing Work Orders from T&D Operations, reviewing Standards and material requests from Warehouse. Addition of a Transmission & Distribution Engineer-in-Training (EIT) would help Yukon Energy make progress towards its future goals.

Since 2018, Customer Connections has seen an increase of 60% in customer requests, including larger and more complex requests. Having an EIT support these requests would allow our Customer Connections Coordinator more time to focus on the larger, more complex subdivision projects. This also provides T&D

Engineering with more flexibility in the future if the department needs to backfill the Customer Connections Coordinator position.

Plans for T&D Engineering include updating EAM for T&D work orders, standards and integrating programs for design and Geographic Information Systems. A T&D EIT would be a gatekeeper and support these programs.

Key roles and responsibilities of this position would include:

- Plan, organize, and direct T&D projects from start to finish;
- Develop T&D engineering designs, drawings, specifications, and cost estimates;
- Prepare T&D technical advisories pertaining to design and material approvals;
- Manage all phases of the project, including concept, design, construction, and closeout;
- Review T&D material requests from Procurement and updating standards;
- Support Customer Connections team as required; and
- Support O&M work orders.

This position will support Capital Projects and Engineering, Operations, Customer Service, EAM, Asset Management, and Warehouse.

This position will address the strategic priority *Invest in people* and technology with the specific action to attract, develop and retain talent and continuing to build and utilize our asset management program to improve asset decision making and realize value from our assets.

Posting of this position is planned for Fall 2026.

APPENDIX 3.3
THERMAL FUEL MIX

APPENDIX 3.3: THERMAL FUEL MIX

In prior GRAs, Yukon Energy used 90% LNG and 10% diesel for the determination of the LTA blended fuel cost to be included in the revenue requirements. Board Order 2024-05, Appendix A, paragraph 89 directed Yukon Energy "to demonstrate, at the time of its next GRA, that the blended thermal ratio proposed by YEC is the correct LTA blended fuel mix."

The following table shows the thermal fuel mix, net of capital and RFID, for 2016-2024 years [2016 was the first year with LNG in service for a full year]. The table also shows actual annual thermal as percent of LTA thermal, indicating how water availability varied during these years.

Table 3.3-1: Thermal Fuel Mix (2016-2024)

	LNG		Diesel		Annaul Thermal % of LTA
	MWh	%	MWh	%	
2016	2,794	55%	2,293	45%	48%
2017	9,638	73%	3,623	27%	100%
2018	29,772	83%	6,183	17%	115%
2019	65,894	97%	2,311	3%	270%
2020	47,714	69%	21,652	31%	103%
2021	21,485	54%	18,122	46%	51%
2022	23,501	60%	15,704	40%	50%
2023	36,389	83%	7,240	17%	59%
2024	44,806	57%	34,076	43%	119%
	Average	**70%**		**30%**	

The LNG share ranged from 54% to 97% for an average of 70% over nine years.

Yukon Energy normally relies on LNG units prior to diesel units due to comparatively lower fuel costs and lower emission levels. However, colder-than-normal weather can lead to higher peaks, requiring diesel generation to meet baseload energy needs, as available LNG units may be running at full capacity. Additionally, there are times when diesel in the north is needed to support the system, especially when transmission lines or hydro units face issues, as occurred in 2024. In some cases, the availability of the LNG units also impact the percentage share of the fuel blend.[1]

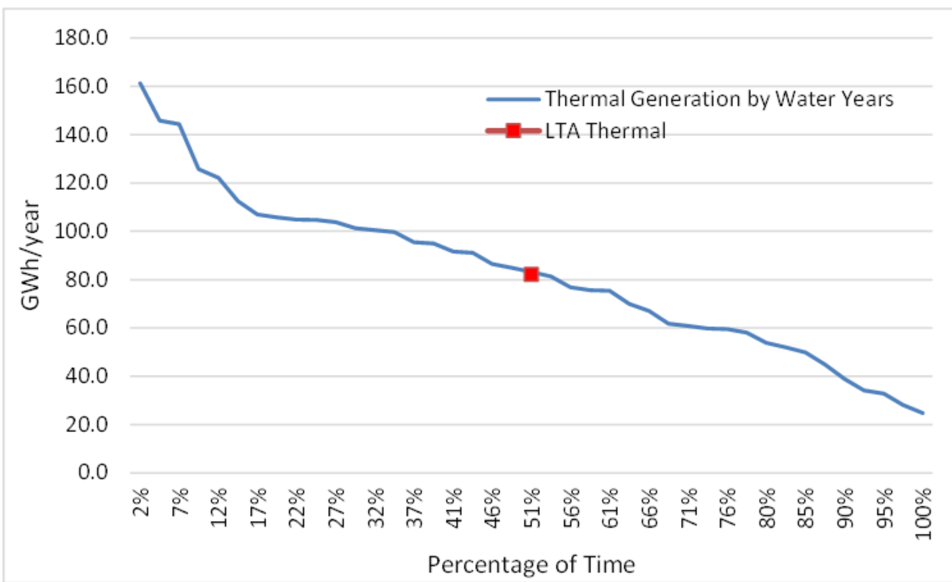
[1] For example, the LNG Unit 1 was not available until November 1, 2020 and after December 15, 2020 impacting the thermal generation mix for 2020/21 winter; Unit 2 was not available from December 16, 2021 to January 16, 2022 impacting the thermal generation mix for 2021/22 winter; Unit 2 was not available after October 22, 2023 until end of March 2024 impacting the thermal generation mix for 2023/24 winter.

The LNG share of total thermal generation is heavily influenced by water conditions. For example, when water levels are above LTA and thermal demand is lower, it is more efficient to operate diesel units.[2]

Under typical conditions, during low water years, the LNG share tends to be higher. For instance, in 2019, low water levels required transfers from the LWRF to Yukon Energy, and the LNG share was approximately 97%.

The following figure shows the LTA thermal generation in relation to the thermal generation over 41 water years for the load at 525 GWh [about the average of three test years]. The figure highlights that at this load level for about 50% of years the thermal generation could be over the LTA, and for 50% of years it could be below the LTA [i.e., median of thermal generation for all water years is close to the LTA]. This figure also highlights the material extent to which LTA thermal is affected by less than 17% of the years with thermal generation requirements exceeding 100 GWh/yr.

Figure 3.3-1: LTA Thermal Generation compared to Thermal Generation over 41 Water Years (for 525 GWh load)



While to date the average allocation has been 70% LNG and 30% Diesel, Yukon Energy has not experienced a prolonged period of below average water conditions – and, therefore, the above results for

[2] The LNG unit operation constrained by unit size at 4.4 MW, i.e., smaller existing diesel units are relied upon for thermal loads less than 2.6 MW [2.6 MW constraint was a direction from the OEM]. While the LNG units can be run at 2.6 MW, there is a negative impact to fuel efficiency by running at this lower load and running at less than optimal loading has a negative effect on maintenance requirements, therefore, it is more efficient to run diesel units for lower loads.

2016 to 2024 do not reflect the LTA water conditions required to be used as the LTA blended fuel mix needed for the current GRA.

Yukon Energy does not have enough evidence at this time to support a change in the LTA blended fuel mix ratio to a 70%/30% mix based on actual results considering the percentages were impacted by the wide range of factors noted. There are also impacts from lower LNG percentages as noted below. Therefore, Yukon Energy is proposing to use an 80% LNG and 20% diesel mix for the fuel cost calculations for the 2025, 2026, and 2027 test years (which is the average between 90/10 and 70/30 based on actuals for the previous years).

Use of a lower allocation of LNG would lead to higher fuel costs. The table below shows the impact of the change in the fuel mix on the revenue requirement for 2025. While this will lead to higher fuel costs compared to the 90/10 mix, the impact will be lower than the 70/30 mix based on actuals as shown in the table below.

Table 3.3-2: Impact of 80% LNG/20% Diesel Fuel Mix on Revenue Requirement (2025)

	2025 With 90/10	2025 With 80/20	2025 With 70/30
LTA Thermal Generation (MW.h)	63,857	63,857	63,857
LNG	57,471	51,086	44,700
Diesel	6,386	12,771	19,157
Fuel Prices, $/kW.h			
LNG Price	$0.2482	$0.2482	$0.2482
Weighted Average Diesel price	$0.3219	$0.3219	$0.3219
LTA Fuel Cost, $000	**$16,320**	**$16,791**	**$17,262**
Maintennace run-ups (MW.h)			
Diesel Run-Ups	21	21	21
LNG Run-Ups	17	17	17
Total Maintenance, $000	**$11**	**$11**	**$11**
Total Fuel Cost, $000	**$16,331**	**$16,802**	**$17,273**
Change from 90/10		**$471**	**$942**

APPENDIX 3.4
VEGETATION MANAGEMENT PLAN

VEGETATION MANAGEMENT PLAN

10-Year Plan to Manage Vegetation along Yukon Energy Corporation Rights of Way

October 7, 2024

10-YEAR PLAN FOR YUKON ENERGY RIGHTS OF WAY

VEGETATION MANAGEMENT PLAN

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10-YEAR PLAN FOR YUKON ENERGY RIGHTS OF WAY

VEGETATION MANAGEMENT PLAN

EXECUTIVE SUMMARY

Yukon Energy enlisted ATCO to prepare a 10-year vegetation management (VM) plan based on best practices to minimize unscheduled maintenance and effectively manage rights of way (ROWs) according to regulation. One of the most critical aspects of integrated vegetation management (IVM) is obtaining an accurate spatial inventory of vegetation along the entire ROW. To develop a program for YEC, ATCO undertook a ground-based spatial inventory patrol of the approximately 1,116 km ROW to understand the scope of mechanical VM work that will be required in the next 10 years. The data gathered during the ground-based inventory patrol helps inform key decisions on the current and future state of YEC's VM program. The following list details some of the key decisions this VM plan will explore:

- Identify all critical sites along the ROWs with 1 m or less clearance from the vegetation to the conductor – Critical sites were reported to YEC during the inventory capture phase so that they could be actioned immediately.
- Complete a current risk assessment of the system and identify any high-priority work (particularly lines L171, L178, L170, L172 and L169)
- Perform a complete spatial inventory of all woody vegetation along the ROWs at the time of inventory patrols
- Obtain an inventory of watercourses that cross the ROW and any other significant features (e.g., bird nests, bear dens) with special environmental requirements that must be considered when developing the VM plan

Using the data gathered from the inventory patrol, ATCO developed this 10-year plan for activities to manage grow-in and fall-in risks on YEC's entire system, including short- and long-term forecasts for mechanical treatments and inventory capture planning costs.

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1.0 OVERVIEW

1.1 BACKGROUND

A strong VM program pays dividends in the long term. From wildfire prevention to bolstering public and worker safety to strengthening system reliability and operational integrity, the benefits of VM are numerous. A properly maintained right of way helps asset owners locate issues more easily from the air and improves access for pole replacements and general maintenance work and patrol activities. In developing this long-term plan and schedule for YEC, ATCO sought to ensure that you reap these benefits and more. We incorporated considerations such as your available budget and your desire to meet FAC-003 level standards, focus more on the reduction of wildfire risks and implement a risk-based VM program across your entire system. We then combined these considerations with criteria such as VM patrol and mechanical treatment cycle requirements for each project line, the growth rate of tree species in the area and potential access and resource constraints.

1.2 2024 VM PLAN UPDATES

From late July to mid-October 2023, 60% of the initial vegetation inventory was captured along YEC ROWs. The remainder of the vegetation inventory on the 1,116 km of ROW was captured from early July to early September in 2024. This revised plan outlined in this document now includes a 1-year schedule based the actual vegetation inventory information obtained between July 2023 and September 2024.

2.0 INITIAL VEGETATION INVENTORY CAPTURE

2.1 INITIAL VEGETATION INVENTORY

The breakdown of the initial inventory area captured in 2023/24 is provided in Table 1, below. In total, there was complete vegetation inventory captured for all 16 project lines (1,116 km of ROW).

Table 1: 2023/24 Initial Inventory

PROJECT	LINE LENGTH	TRIM	SLASH	MOW[1]	TOTAL	HAZARD TREES	DANGER TREES	MECHANICAL WIDEN
Line Number	**KM**	**M²**	**M²**	**M**	**M²**	**# of Trees**	**# of Trees**	**M²**
L171	131	0	16,623	3,552,178	3,568,801	22	386	511,772
L170	147	4,572	407,594	3,575,765	4,050,931	97	506	682,136
L178	190	2,832	449,188	3,9,70,531	4,422,551	486	489	1,327,236
L173	71	648	98,535	2,045,034	2,144,217	40	1,174	166,018
L172	25	0	10,720	539,493	550,213	14	474	44,361
L169	7	282	7,470	120,180	127,932	0	5	0
L355	53	0	1,963	1,110,645	1,112,608	76	0	0
L254	29	0	14,837	458,288	473,125	16	32	780
L177	172	1,701	362,493	3,073,750	3,437,944	85	0	5,962
L174	95	705	32,144	2,363,410	2,396,259	157	602	106,612
L176	52	1,220	171,516	765,326	938,062	26	0	0
L180	31	0	67,904	542,849	610,753	64	83	25,830
L175	6	0	6,508	133,185	139,693	80	0	0

PROJECT	LINE LENGTH	TRIM	SLASH	MOW[1]	TOTAL	HAZARD TREES	DANGER TREES	MECHANICAL WIDEN
L356	73	559	214,407	523,330	738,296	12	0	0
L250	21	85	41,462	234,791	276,338	9	52	19,416
L453	8	1,147	8,142	48,436	57,725	54	0	0
Total	**1,116**	**13,751**	**1,974,506**	**23,057,191**	**25,045,448**	**1,238**	**3,803**	**2,890,123**

During the initial vegetation inventory capture, ATCO obtained an inventory of the potential herbicide area in case potential cost savings, system reliability and access improvements needed to be assessed. For the initial inventory area included in Table 1, the herbicide area is included in the mow treatment area amounts.

The majority (92.1%) of the current on ROW (O&M) work is the mow operation, which isn't surprising, as this is consistent with most northern Canadian utility system ROWs. The next biggest component of on ROW vegetation management is slash (7.8%). Slash is a much more labour-intensive treatment than mow, so it is only prescribed on sites where mowing is not possible due to factors such as steep slopes, too much rock and wet ground. Lastly, the trim task comprises less that 0.1% of the ROW inventory. This is to be expected, as trim should not occur on a ROW unless very good growing seasons cause "cycle buster" sites, a landowner refuses complete removal of a site or funding levels and the VM program do not allow for proper risk-based management.

Most of the current off ROW (capital) work is made up of the mechanical widen task. This again isn't surprising for a northern Canadian utility system ROW, as when the ROW is built and maintained, governments do not allow the removal of live trees that can be classified as danger trees unless special approval is authorized. Danger trees are defined as trees that are completely healthy but if they do come over in a storm or similar event, will fall within flashover distance of the powerline conductors. Because of the approval constraints on mechanical widen programs, it is logical to see over 3,800 danger trees identified in the inventory. This is natural in forested landscapes where mechanical widen programs have been absent. Lastly, just over 1,200 hazard trees were identified during this inventory capture. Hazard trees are defined as trees that are predisposed to fall within flashover distance of the conductor because they are dead, dying or have a significant lean. Hazard trees will likely fall onto the conductor or within flashover distance as some point if they are not removed.

2.2 INVENTORY CAPTURE CONSTRAINTS AND CONSIDERATIONS

Two things stand out during this initial inventory capture phase: the amount of vegetation both on and off the ROW, and the restricted access to many locations along the ROW. Steep slopes, wet ground and large watercourses create many isolated locations that require frozen access or even fly-in access during non-frozen conditions.

The ROWs also has limited access points, so a lot of time is spent travelling to and from sites. Due to the limited access points and other restrictions mentioned, much of these ROWs should be patrolled by two-person crews.

3.0 INITIAL RISK ASSESSMENT

3.1 IMMEDIATE ACTION PLAN (CRITICAL CLEARANCE SITES)

During the initial inventory capture, ATCO identified several critical clearance sites. Critical clearance locations are defined as areas where the vegetation is 1 m or less from the conductor at the time of patrol. These sites were drawn up and sent to YEC for immediate action promptly after being identified. Table 3, below, lists the areas associated with critical sites for the eight lines patrolled so far.

YEC also made ATCO aware that sections of L170, L177, L176 and L356 have been or will be worked on in 2023. ATCO recommends completing only the critical sites on L170 and completing all remaining work in 2024 using the new workplan obtained in 2023/24. All work on other lines in 2023 can be completed as planned, as inventory will not be captured on these lines until summer 2024 and this updated inventory will capture this completed work.

This immediate action plan ensures that all critical sites identified during the inventory patrol will be completed in 2023 and all work planned for 2024 will be executed using the workplans derived from the initial inventory capture. This approach will ensure that starting in 2024, YEC's ROWs can be fully managed using a risk-based approach. This risk-based approach is described in the short-term action plan laid out in the next section.

Table 3: 2023/24 Critical Sites Identified

PROJECT	TRIM	SLASH	MOW[1]	TOTAL	HAZARD TREE
Line Number	**M²**	**M²**	**M²**	**M²**	**# of Trees**
L171	0	1,200	0	1,200	0
L170	1,782	50,662	23,260	82,124	0
L178	2,256	5,800	5,100	13,156	10
L173	648	3,775	0	10,510	0
L172	0	0	0	0	0
L169	0	0	0	0	0
L355	57	820	6,465	7,342	0
L254	0	0	0	0	0
L177	1,408	11,265	12,704		
L174	0	0	0		
L176	1,220	2,666	21,734		
L180	0	0	0		
L175	0	0	0		
L356	0	0	0		
L250	85	663	0		
L453	0	0	0		
Total	**7,456**	**76,851**	**69,263**	**153,570**	**10**

3.2 SHORT-TERM ACTION PLAN (2024 TO 2027)

The main purpose of the short-term action plan is to change YEC's VM program from a line, geographic or section-based approach to a risk-based VM management approach. Step one of the risk-based approach is obtaining a full inventory of the system so that immediate risks can be identified and actioned. For the 1,116 km of vegetation inventory captured in 2023/24, this has been completed with the removal of all identified critical clearance sites.

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Step two of the risk-based approach is to align the remainder of the risks with the current annual funding levels to determine whether the current funding is sufficient to implement a successful risk-based VM program. The decision has been made to work within the upper range of current funding levels.

3.2.1 2024 Action Plan

Based on the vegetation inventory captured to date, it is apparent that the current funding levels are not conducive to the current line, geographic or section-based VM approach. The best and easiest way to implement a risk-based approach on any powerline is to manage the system based on clearance. The goal of any VM program on an overhead electrical system should be to maximize clearance to the conductor of all on ROW vegetation while striving to remove all fall-in potential. Based on the vegetation inventory obtained, ATCO determined that all vegetation with 1.1 m to 3.0 m of clearance to the conductor will be removed in 2024. Table 4, below, shows the O&M forecast cost to remove all identified vegetation with 1.1 m to 3.0 m of clearance.

It was recommended last year, work on the 2023 inventoried lines should occur prior to the 2024 growing season to avoid vegetation getting within the critical 1 m clearance distance. Work on the 2024 inventoried lines should be completed before the end of 2024, or the growing season of 2025 if budgets are a limiting factor.

Table 4: 2024 O&M Work Forecast

PROJECT	TRIM	SLASH	MOW[1]	TOTAL	O&M MECHANICAL WORK
Line Number	**M^2**	**M^2**	**M^2**	**M^2**	**$**
L171	0	5,537	6,471	12,008	21,004
L170	2,790	122,301	135,838	260,929	474,087
L178	32	48,535	57,315	105,882	184,801
L173	0	22,588	241,154	263,742	268,227
L172	0	10,220	0	10,220	28,616
L169	0	1,192	0	1,192	3,338
L355	0	73	60,589	60,662	51,705
L254	0	183	0	183	512
L177	217	25,858	255,793	281,868	291,085
L174	705	7,700	17,390	25,795	40,431
L176	0	0	40,619	40,619	34,526
L180	0	0	0	0	0
L175	0	0	0	0	0
L356	120	68,977	171,860	240,957	339,913
L250	0	2,080	5,599	7,679	10,583
L453	707	1,179	0	1,886	7,402
Total	**4,571**	**316,423**	**992,628**	**629,895**	**1,756,230**

It is important to distinguish the capital (off ROW) work from the ongoing O&M work, as they fall under different budget allocations and have very different approval mechanisms. In a risk-based VM approach, we must manage and defend our VM programs to regulators in ways they can understand and appreciate based on sound science and logical risk assessment criteria.

Identifying and classifying trees as hazard trees and danger trees allows for a simple explanation of risk-based management for off ROW vegetation. Hazard trees present the highest risk, as due to a physiological or biological reason, they are predisposed to falling on the conductor or within flashover distance. Danger trees present the next highest risk; if a wind, snow or large storm event occurs and blows these trees over, they will likely cause an outage and/or wildfire when they fall.

The most challenging off ROW work on which to gain approval is mechanical widenings, as these programs do not pose immediate potential danger to the electrical system. The reason these programs are considered is to avoid future hazard tree or danger tree situations.

Based on the above reasons, the plan in 2024 is to remove all hazard trees identified on all ROWs while also removing all identified danger trees. If the funding for this is not available, priority should be given first to hazard trees and then to danger trees. If necessary, the danger tree program can be spread out over two or three years. Table 5, below, outlines the forecast funding required for each capital maintenance program.

Because L171 was deemed to be the highest priority line, ATCO proposes beginning an annual mechanical widening program in 2024 that will span over a decade. If capital funding is not available, or if approval for mechanical widening cannot be obtained, then the focus should be on a strong hazard tree and danger tree program.

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Table 5: 2024 Capital Work Forecast

PROJECT	HAZARD TREE	HAZARD TREE	DANGER TREE	DANGER TREE	MECHANICAL WIDENING	MECHANICAL WIDENING
Line Number	**# of Trees**	**$**	**# of Trees**	**$**	**M²**	**$**
L171	22	3,630	386	63,690	271,400	949,900
L170	97	16,005	506	83,490	0	0
L178	476	78,540	489	80,685	0	0
L173	40	6,600	1,174	193,710	0	0
L172	14	2,310	474	78,210	0	0
L169	0	0	5	825	0	0
L355	76	12,540	0	0	0	0
L254	16	2,640	32	5,280	0	0
L177	85	14,025	0	0	0	0
L174	157	25,905	602	99,330	0	0
L176	26	4,290	0	0	0	0
L180	64	10,560	83	13,695	0	0
L175	80	13,200	0	0	0	0
L356	12	1,980	0	0	0	0
L250	9	1,485	52	8,580	0	0
L453	54	8,910	0	0	0	0
Total	**1,228**	**202,620**	**3,803**	**627,495**	**271,400**	**949,900**

3.2.2 2025 Action Plan

Based on the vegetation inventory obtained, ATCO recommends that in 2025, all vegetation with 3.1 m to 3.5 m of clearance to the conductor will be removed. Table 6, below, shows the O&M forecast cost to remove all identified vegetation with 3.1 m to 3.5 m of clearance.

Table 6: 2025 O&M Work Forecast

PROJECT	TRIM	SLASH	MOW[1]	TOTAL	O&M MECHANICAL WORK
Line Number	**M²**	**M²**	**M²**	**M²**	**$**
L171	0	1,500	269,940	271,440	233,649
L170	0	55,895	496.237	552,132	578,307
L178	0	6,065	103,795	109,860	105,208
L173	0	3,270	42,643	45,913	45,403
L172	0	0	17,450	17,450	14,833
L169	0	0	0	0	0
L355	0	0	0	0	0
L254	0	0	0	0	0
L177	14	13,110	74,774	87,898	100,347
L174	0	6,715	2,000	8,715	20,502
L176	0	2,508	15,351	17,859	20,071
L180	0	900	845	1,745	3,238
L175	0	0	2,250	2,250	1,913
L356	0	0	46,125	46,125	39,206
L250	0	1,206	996	2,202	4,223
L453	0	0	0	0	0
Total	**14**	**62,770**	**1,072,406**	**1,163,589**	**1,166,900**

In 2025, assuming the hazard trees and danger trees identified in the initial inventory capture were all removed in 2024, the only capital maintenance program planned for off ROW vegetation is to complete the mechanical widening on L171 and to start this program on L170. Table 7, below, outlines the expected mechanical widening program costs in 2025.

Table 7: 2025 Capital Work Forecast

PROJECT	HAZARD TREE	HAZARD TREE	DANGER TREE	DANGER TREE	MECHANICAL WIDENING	MECHANICAL WIDENING
Line Number	**# of Trees**	**$**	**# of Trees**	**$**	**M²**	**$**
L171	0	0	0	0	240,372	841,302
L170	0	0	0	0	31,208	108,598
Total	**0**	**0**	**0**	**0**	**271,400**	**949,900**

3.2.3 2026 Action Plan

Based on the vegetation inventory obtained, ATCO recommends that in 2026, all vegetation with 3.6 m to 4.0 m of clearance to the conductor will be removed on higher-priority lines L171, L170 and L173. The annual funding is

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currently insufficient to remove all vegetation with 4 m clearance in 2026. Table 8, below, shows the O&M forecast cost to remove all identified vegetation with 3.6 m to 4.0 m of clearance.

Table 8: 2026 O&M Work Forecast

PROJECT	TRIM	SLASH	MOW[1]	TOTAL	O&M MECHANICAL WORK
Line Number	**M²**	**M²**	**M²**	**M²**	**$**
L171	0	8,750	582,767	591,517	519,852
L170	0	64,166	693,758	757,924	769,359
L178					
L173	0	3,500	188,641	192,141	170,145
L172					
L169					
L355					
L254					
L177					
L174					
L176					
L180					
L175					
L356					
L250					
L453					
Total	**0**	**76,416**	**1,465,166**	**1,541,852**	**1,459,356**

Note: Lines with no volumes have not been patrolled, so the forecast is based on project line length.

In 2026, the only capital maintenance program planned is a portion of L170 to be mechanically widened. Table 9, below, outlines the forecast capital costs for 2026.

Table 9: 2026 Capital Work Forecast

PROJECT	HAZARD TREE	HAZARD TREE	DANGER TREE	DANGER TREE	MECHANICAL WIDEN	MECHANICAL WIDEN
Line Number	**# of Trees**	**$**	**# of Trees**	**$**	**M²**	**$**
L170	0	0	0	0	271,400	949,900

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PROJECT	HAZARD TREE	HAZARD TREE	DANGER TREE	DANGER TREE	MECHANICAL WIDEN	MECHANICAL WIDEN
Total	**0**	**0**	**0**	**0**	**271,400**	**949,900**

3.2.4 2027 Action Plan

Based on the vegetation inventory obtained, ATCO recommends that in 2027, all remaining vegetation with 3.6 m to 4.0 m of clearance to the conductor will be removed from the system. Table 10, below, shows the O&M forecast cost to remove all remaining identified vegetation with 3.6 m to 4.0 m of clearance.

Table 10: 2027 O&M Work Forecast

PROJECT	TRIM	SLASH	MOW[1]	TOTAL	O&M MECHANICAL WORK
Line Number	**M²**	**M²**	**M²**	**M²**	**$**
L171					
L170					
L178	0	68,460	386,350	454,810	520,086
L173					
L172	0	180	49,215	49,395	42,337
L169	282	0	0	282	1,636
L355	0	1,425	49,318	50,743	45,910
L254	0	1,668	0	1,668	4,670
L177	0	10,984	160,015	170,999	166,768
L174	0	675	14,396	15,071	14,127
L176	0	900	32,732	33,632	30,342
L180	0	100	11,340	11,440	9,919
L175	0	0	0	0	0
L356	0	25,350	115,060	140,410	168,781
L250	0	864	6,670	7,534	8,089
L453	0	0	1,656	1,656	1,408
Total	**282**	**110,606**	**826,752**	**937,640**	**1,014,072**

In 2027, the only capital maintenance program planned is on another portion of L170 to be mechanically widened. Table 11, below, outlines the forecast capital costs for 2027.

10-YEAR PLAN FOR YUKON ENERGY RIGHTS OF WAY

VEGETATION MANAGEMENT PLAN

Table 11: 2027 Capital Work Forecast

PROJECT	HAZARD TREE	HAZARD TREE	DANGER TREE	DANGER TREE	MECHANICAL WIDEN	MECHANICAL WIDEN
Line Number	**# of Trees**	**$**	**# of Trees**	**$**	**M^2**	**$**
L170	0	0	0	0	271,400	949,900
Total	**0**	**0**	**0**	**0**	**271,400**	**949,900**

4.0 LONG-TERM ACTION PLAN

By the end of 2027, all vegetation inventory identified in 2023 and 2024 within 4 m of the conductor will have been removed from the system. This means that anything identified with 4.1 m to 5 m clearance during the original inventory capture will likely now be close to within the 1 m critical clearance from the conductor prior to the growing season in 2028. Knowing this allows ATCO to make the following recommendations for the ongoing and long-term action plans for YEC's risk-based VM program.

4.1 RECOMMENDATIONS

These recommendations have all been made under the assumption that the O&M funding level will stay at slightly above $1.45M per year for the foreseeable future and that hazard tree funding will always be available. If a recommendation does not follow these assumptions, then the actual assumption will be indicated in the recommendation itself.

4.1.1 Vegetation Inventory Capture

Patrolling and inventory capture should be completed for the entire ROW every four years. This inventory capture should be spread over two years to allow for optimal ground access while freeing up enough funding to handle the critical clearance sites identified in the first phase of each inventory capture cycle.

For the next inventory capture cycle, ATCO recommends not gathering herbicide information so that vegetation can be properly classified as requiring mow or slash operations. We also recommend against identifying mechanical widenings again across the entire system unless they are captured for individual lines or sections of lines because there is a budget and a desire to do these widenings.

ATCO recommends that hazard tree inventory capture be part of every inventory capture cycle. Also, YEC must determine its preferred approach to danger trees. Maybe danger trees become a modified mechanical widening program, but they are only completed on lines with voltages 138 kV and above based on the priority of the line and the availability of funding. This will be discussed more in the sections below.

4.1.2 Critical Site Management (Unplanned Events)

Under this new four-year cycle of inventory capture and risk-based management based on vegetation-to-conductor clearance, unplanned events or "cycle busters" on the system should only occur in the first year of the inventory capture cycle each time through. This will only be the case if YEC adheres strictly to the concept of managing by clearance.

4.1.3 Risk-Based O&M VM Program

The risk-based VM program works entirely off the growth rate assumptions for each tree species, so the better the inventory information around tree species and the site index of each area, the better the program can be prioritized to manage risk. For instance, a spruce tree with 3 m clearance will take longer to become an issue on a powerline compared to an aspen tree, or a spruce tree in an area with a higher site index will likely become an issue sooner than one with the same clearance on a lower site index location.

4.1.4 FAC-003-like VM Program

There are two main components of FAC-003 compliance. The first component is to establish a transmission vegetation management plan (TVMP) that focuses on inspections of the ROW to assess vegetation risks and inventory and plan required work. This can be done through air patrols (annual line flights), detailed air patrols (LiDAR or satellite) or detailed ground patrols. YEC will have a detailed ground patrol of its entire system by the end of August or September 2024. This approach is usually the most economical method while still allowing good accuracy and the ability to identify hazard trees with an on-site assessment.

The second component of FAC-003 compliance is to establish a transmission vegetation management annual plan (TVMAP) that outlines all the planned vegetation work treatment activities each year. The three main types of work identified in the TVMAP are the mechanical on ROW programs, the herbicide on ROW programs and the off-ROW hazard reduction programs.

To be FAC-003 compliant is also crucial to ensure detailed documentation of each project (line). The way ATCO captured the vegetation inventory allows for FAC-003 reporting and documentation. The patrols were done by line, from substation to substation, with detailed inventory captured. Using the patrols in conjunction with the issued workplans and then having the crews and YEC sign off on the workplans when completed allows for a detailed audit trail. This process shows that the entire ROW was inventoried, and work completed following a risk-based approach. It also shows that the work was marked as completed and inspected to verify that quality standards were achieved.

The last component to a FAC-003–compliant system is to ensure that all activities on your system are carried out by competent workers. ATCO accomplishes this by ensuring that our workers hold certain certifications/credentials or possess a minimum amount of direct work experience in the industry. We recommend using certified Utility Arborists (UA), Utility Tree Trimmers (UTT), Utility Tree Workers (UTW) or registered forest professionals (RPF or RPFT). All patrollers used on ATCO’s FAC-003 lines and all patrollers sent to complete YEC’s initial inventory capture have at least one of these certifications or a minimum of five years’ experience patrolling powerline ROWs.

4.1.5 Wildfire Risk Management (Hazard Reduction Program)

No government jurisdiction will allow for the complete removal of off ROW vegetation along powerline ROWs managed by utility companies. As such, ATCO recommends that YEC take a measured approach to off ROW hazard reduction programs. The hazard reduction program includes all capital activities identified earlier in this VM plan (hazard trees, danger trees and mechanical widening). ATCO recommends that a cyclical hazard reduction program is always planned in conjunction with the cyclical on ROW O&M program. This ensures fewer entries onto a ROW and allows for cost efficiencies and synergies with the crews carrying out the work. Under this plan, the highest-risk hazard reduction programs (hazard trees and danger trees) would be completed every four years on each ROW, and the mechanical widening program would be done annually as funding and approvals allow. Mechanical widening programs do not have to be part of the hazard reduction program when robust hazard tree and danger tree programs are in place.

The other main ingredient to a hazard reduction program is the inventory patrols required to identify new hazard trees and danger trees as the forest stands mature. As previously mentioned, the hazard inventory capture and the hazard tree mechanical program is four years, which is very consistent with most transmission systems.

4.1.6 Future O&M Funding Levels

The average annual O&M funding level over the next 12-year period is $1.498M. Right now, this assumes a four-year cycle on inventory capture and mechanical execution of all ROWs while allowing for clearance to the conductor of greater than 1 m at any time in the cycle (unless there happens to be a cycle buster).

The current risk-based approach to remove all vegetation within 4 m clearance over this four-year cycle length does not leave much flexibility for certain tree species, especially if tree growth rates continue their current trajectory. There will likely need the be a budget of roughly $100K allocated for unplanned events and the discovery of critical sites during inventory patrols every four years.

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

4.1.1 Rider J – Yukon Energy Revenue Shortfall Rider resulting from the 2025-27 GRA

Rider J is applicable to all Yukon Energy and AEY firm retail and industrial rates (all AEY recoveries from this rider would flow through to Yukon Energy). The existing Rider J is 55.40% for non-industrial rates and 51.75% for industrial rates.

The Rider J increase to each existing Rider J to recover the Application revenue shortfalls is 26.38 percentage points (i.e., from 55.40% to 81.78% for non-industrial rates and from 51.75% to 78.13% for industrial rates) for the 2025 test year, a further 17.53 percentage points (i.e., from 81.78% to 99.31% for non-industrial rates and from 78.13% to 95.66% for industrial rates) for the 2026 test year and a further 13.26 percentage points (i.e., from 99.31% to 112.57% for non-industrial rates and from 95.66% to 108.92% for industrial rates) for the 2027 test year.

As noted below, interim refundable rates at the Rider J rate levels for retail and industrial customers are sought effective July 1, 2025 and effective January 1, 2026, with final 2025 and 2026 rates effective April 1, 2026 and final 2027 rates effective January 1, 2027.

4.1.2 Proposed Interim Rates

The interim refundable Rider J increases are proposed to take into account the following:

- The Board in Appendix A to Board Order 2021-08 (paragraphs 3-5) reviewed its jurisdiction to approve interim rates and stated that the "Board considers that the purpose of interim rates is two-fold. First, interim rates provide a smooth rate transition for customers to new rates in order to minimize rate shock. Second, they provide additional cash flow to the utility to cover increased costs while its rate case is being tested. The Board assesses an interim rate request with this purpose in mind." The Board's directions recognize that, absent interim rates, rate changes to reflect test year conditions would be delayed until a final Board approval of a compliance filing for the Application. Interim rates address that delay in a manner that avoids rate shock and intergenerational inequity resulting from the large true-up added rate rider that would otherwise be required to recover the resulting revenue shortfalls for the test years in the Application.

- As per discussions with prior intervenors, the true-up Rider (Rider J1) is a cause of much concern and Yukon Energy has been challenged to minimize this. Yukon Energy has responded by submitting this Application as early in the year as possible[1] (subject to various levels of submission approval) to allow for an interim Rider to be effective July 1 of the first test year. Yukon Energy does note that this could be improved in the next GRA by submitting in the year prior to the first test year. To assist with increasing the likelihood of this occurring, this GRA is for three test years which should allow sufficient time between Board approval of this GRA, and preparation time required for the next GRA.[2]

- In addition, the true-up Rider (Rider J1) can be minimized by approval of a higher interim Rider J. Any incremental revenues collected near the beginning reduces the true-up Rider at the end and assists with charging rates to the time period when users are consuming the energy (achieving better intergenerational equity).

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[1] The final Board Order for the 2023/24 Yukon Energy GRA Compliance Filing was issued on September 13, 2024. Yukon Energy was then able to update its forecasts and finalized its 2025 Business Plan in December of 2024. Updates and adjustments for 2025, 2026 and 2027 were performed in January through March 2025. The submission date was slightly delayed as Yukon Energy explored options to reduce the requested rate increases by trying to obtain certainty of capital contributions. Yukon Energy's previous GRA was submitted August 31, 2023.

[2] Assuming the 2025-2027 GRA is finalized in 2026, Yukon Energy could prepare the next GRA in 2027 and file before the 2028 test year and interim refundable rates could be effective early in 2028 for the 2028 test year.

Section 1.1.7 of Tab 1 reviews the interim rate approach adopted for this GRA, including tables showing residential customer bill impacts over the three test years under three potential interim rate options. The Tab 1 analysis results, as summarized below, shows how a higher interim Rider J assists with rate smoothing.[3]

- **Option 1 (Bill Smoothing[4])** – July 1, 2025 at about two-thirds of the 2025 increase, January 1, 2026 at about 85% of the 2026 increase, April 1, 2026 true-up for 2025 and 2026 test years, January 1, 2027 final rates for 2027 test year.
  - Cumulative residential bill increase by January 1, 2027 of 34.3% ($83.62).
- **Option 2 (Summertime Increases)** – July 1, 2025 at 100% of the 2025 increase, April 1, 2026 at 100% of the 2026 increase plus true-up for 2025 and 2026 test years, January 1, 2027 final rates for 2027 test year.
  - Cumulative residential bill increase by January 1, 2027 of 35.1% ($85.58).
- **Option 3 (Minimize True-Up)** – July 1, 2025 at 100% of the 2025 increase, January 1, 2026 at 100% of the 2026 increase, April 1, 2026 true-up for 2025 and 2026 test years, January 1, 2027 final rates for 2027 test year.
  - Cumulative residential bill increase by January 1, 2027 of 30.9% ($75.38).

Yukon Energy proposes Option 1. Consistent with prior Board direction, the interim refundable rates proposed to take effect on July 1, 2025 and January 1, 2026 are aimed at providing a smooth rate transition for customers in order to minimize rate shock and to provide greater bill stability to Yukoners. To achieve the proposed bill impacts, the technical changes to Rider J are detailed below.

- **Rider J – Yukon Energy July 1, 2025 Interim Revenue Shortfall Rider** – An interim refundable increase to Rider J of 17.89 percentage points (from 55.40% to 73.29% for non-industrial and from 51.75% to 69.64% for industrial customers) effective July 1, 2025 and applicable to all Yukon Energy and AEY firm retail and industrial rates (all AEY recoveries from

[3] Each option examined average (non-government) residential bill impact for 1,000 kWh/month consumption as an example considering most of the ratepayers in the Yukon are residential customers.
[4] Yukon Energy defines rate smoothing as maintaining a relatively flat level of rate increases over time rather than smaller increases followed by larger increases.

this rider would flow through to Yukon Energy). Yukon Energy is proposing a July 1, 2025 interim rate to reduce the impact of customer bills on 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, 2026 Interim Revenue Shortfall Rider** – An interim refundable increase to Rider J of 19.66 percentage points (from 73.29% to 92.95% for non-industrial and from 69.64% to 89.30% for industrial customers) effective January 1, 2026 and applicable to all Yukon Energy and AEY firm retail and industrial rates (all AEY recoveries from this rider would flow through to Yukon Energy). Yukon Energy is proposing a January 1, 2026 interim rate to reduce the impact of customer bills on final rates. 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 in the spring of 2026, given the current timing estimates. In order to reduce customer bill volatility, Yukon Energy seeks approval of the 2025-27 GRA final rates for the 2025 and 2026 test years and true-up rider, if required, effective April 1, 2026, and final 2027 test year rates effective January 1, 2027 as this will enable coordination of the rate increase with the removal of the 2023/24 Yukon Energy GRA true-up Rider J1 of 9.45% which is in effect until December 31, 2026.

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. The revenues from secondary sales are used as an offset to the required revenues from retail rates for firm power.

The rates charged to customers for firm sales are designed to yield the revenue requirements set out in Tab 3, net of $0.413 million forecast non-rate revenues[5] and secondary sales forecast revenues of $0.287 million for each 2025, 2026 and 2027 test years.

The revenue required from firm rates is $106.692 million in 2025, $121.706 million in 2026 and $134.150 million in 2027, compared to Yukon Energy's forecast revenues from existing firm electrical rates

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

(including the existing Rider J) at $87.089 million in 2025, $88.505 million in 2026 and $90.105 million in 2027.

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 $19.603 million rate revenue shortfall in 2025, a $33.201 million rate revenue shortfall in 2026 and a $44.045 million rate revenue shortfall in 2027 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)

	2025	**2026**	**2027**
Revenue Requirement	$107,392	$122,406	$134,850
Less: Other Revenues	$413	$413	$413
Less: Secondary Sales	$287	$287	$287
Revenue Required from Firm Rates	$106,692	$121,706	$134,150
Less: Revenues from Firm Sales at Existing Rates [includes Rider J at 2023/24 GRA]	$87,089	$88,505	$90,105
Additional Firm Rate Revenues Required	$19,603	$33,201	$44,045

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 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 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.[6] 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, the Rider F mechanism was used to normalize the price variances in secondary sales.

Based on the existing mechanism, the latest secondary rates are 9.8 cents per kWh for secondary wholesale and 10.9 cents per kWh for secondary retail.[7] 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.

4.4 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". For the 2025, 2026 and 2027 there are two major industrial customers, Victoria Gold (VGC Group)[8] and Hecla Yukon. No other major industrial customers are forecast to require service under Rate Schedule 39 in the test years.

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 11 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

[6] 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.
[7] The rates are effective April 1, 2025, as filed with the Board.
[8] See Tab 2 for notes regarding the VGC Group load assumptions.

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. OIC 2018/220 has repealed the prior expiry provisions related to Section 2.1, 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.[9]

The existing Rider J rate applicable for major industrial customer rates (Rate Schedule 39) is 51.75%. In conformance with OIC 2018/220 and the Rider J increases reviewed in Table 4.3, the existing Rider J applicable to Rate Schedule 39 is to be increased by 26.38 percentage points (from 51.75% to 78.13%) for 2025, a further 17.53 percentage points (from 78.13% to 95.66%) for 2026, and a further 13.26 percentage points (from 95.66% to 108.92%) for 2027 (applicable total Rider J rate for major industrial customers rates of 78.13% for 2025, 95.66% for 2026 and 108.92% for 2027). The interim refundable Rider J increase of 17.89 percentage points effective July 1, 2025, and a further 19.66 percentage points effective January 1, 2026 would apply to Rate Schedule 39.

4.4.2 VGC Group and Hecla Yukon Fixed Charge

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 Alexco Resource Corp Power Purchase Agreement (PPA) approved in 2011 by Order 2011-01, and confirmed in the VGC Group PPA[10] approved in 2018 by Board Order 2018-04.

Rate Schedule 39 as currently approved includes a Fixed Charge for VGC Group of $47,322.78/month and for Hecla Yukon of $21,647.02/month. The Fixed Charges are adjusted at year-end as per provision of the Rate Schedule 39.[11]

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[9] 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."

[10] The Power Purchase Agreement (PPA) dated November 9, 2017 between Yukon Energy, Victoria Gold Corp., and StrataGold Corporation (Victoria Gold Corp. and StrataGold Corporation are collectively, the VCG Group) for transmission connection to the mine site.

[11] Fixed Charges were last updated in the 2023/24 GRA to reflect new capital costs related to the Transmission Facilities as well as the last approved ROE and cost of debt. Yukon Energy is not proposing to update the Rate Schedule 39 Fixed Charges as there are no new capital additions related to the Transmission Facilities subject to the Fixed Charges.

Considering uncertainties around the VG loads, Yukon Energy is not proposing changes to the Fixed Charges charged to VGC Group and Hecla Yukon. Based on Rate Schedule 39 requirements, within 60 days of calendar year end, Yukon Energy will adjust the allocation of Fixed Charges based on each mine's actual share of the load on the Transmission Facilities.

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 2025, 2026 and 2027 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 Yukon Energy 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 Yukon Energy Rider J and AEY Rider R (i.e., excludes customers served under Rate Schedule 32, as well as Rider J1, Rider F and Rider E):

  - Rate increase of 15.57% for 2025 [Table 4.2, line 5a];
  - A further increase of 8.95% for 2026 [Table 4.2, line 10a]; and
  - A further increase of 6.21% for 2027 [Table 4.2, line 15a]; compounded increase of 33.73% [Table 4.2, line 17].
- A Rider J increase of 57.17 percentage points[12] is equal to a 'rate' increase of 33.73% (as shown in Table 4.2, line 3 the total consolidated revenues for 2027 at $130.591 million times rate increase of 33.73% results in $44.045 million incremental revenues; $44.045 million divided by consolidated base rate revenues of $77.039 million, sum of lines 1a and 1 b, results in a Rider J increase of 57.17 percentage points).
- Considering that the current Yukon Energy Rider J is applied only to base rates, the required new Rider J increase from the current 55.40% for non-industrial and 51.75% for industrial class:
  - Increase to 81.78% for non-industrial and 78.13% for industrial class to recover the 2025 test year shortfall;
  - Increase to 99.31% for non-industrial and 95.66% for industrial class to recover the 2026 test year shortfall; and
  - Increase to 112.57% for non-industrial and 108.92% for industrial class to recover the 2027 test year shortfall.

The calculations of Rider J are provided in Table 4.2.

[12] Equal to the summation of Lines 5b, 10b and 15b in Table 4.2.

Table 4.2:
Calculation of Required 2025-27 Rate Increases and Rider J

Line #			Forecast 2025	Forecast 2026	Forecast 2027
1a	Consolidated Firm Retail Sales Revenues - Base Rates[1]	$000	68,577	69,979	71,411
1a (i)	*YEC Firm Retail Base Rates Revenues*	*$000*	*9,404*	*9,504*	*9,606*
1a (ii)	*AEY Firm Retail Base Rates Revenues*	*$000*	*59,173*	*60,475*	*61,805*
1b	Consolidated Firm Industrial Sales Revenues - Base Rates	$000	5,724	5,628	5,628
2a	Consolidated Rider J Revenues	$000	40,954	41,681	42,474
2b	AEY Rider R Revenues	$000	10,685	10,872	11,078
3=1+2	**Total Consolidated Firm Sales Revenues at existing rates**	$000	125,940	128,160	130,591
4=Table 4.1	Retail Revenue increase required in 2025	$000	19,603		
5a=4/3	Required Rate Increase on total Consolidated Revenues	%	15.57%		
5b=4/(1a+1b)	Rider J Increase Required	%	26.38%		
6=3 + (1a+1b)* 5b	**Total Consolidated Firm Sales Revenues with 2025 Increase**	$000	145,543	148,107	150,916
7=Table 4.1	Retail Revenue increase required in 2026	$000		33,201	
8=6-3	To Be Recovered from 2025 Increase	$000		19,947	
9=7-8	Net Retail Revenue increase required in 2026	$000		13,254	
10a=9/6	Required Rate Increase on total Consolidated Revenues	%		8.95%	
10b=9/(1a+1b)	Rider J Increase Required	%		17.53%	
11=6 * 10a	**Total Consolidated Firm Sales Revenues with 2026 Increase**	$000		161,361	164,421
12=Table 4.1	Retail Revenue increase required in 2027	$000			44,045
13=11-3	To Be Recovered from 2025 and 2026 Increases	$000			33,830
14=12-13	Net Retail Revenue increase required in 2027	$000			10,215
15a=14/11	Required Rate Increase on total Consolidated Revenues	%			6.21%
15b=14/(1a+1b)	Rider J Increase Required	%			13.26%
16=11 * 15a	**Total Consolidated Firm Sales Revenues with 2027 Increase**	$000			174,636
17=12/3	Total Cumulative 2025 - 2027 Rate Increases				33.73%
	Rider J Required				
18=5b, 10b, 15b	Rider J Increase Required	%	26.38%	17.53%	13.26%
19	Existing Rider J - non-industrial	%	55.40%	81.78%	99.31%
20	Existing Rider J - industrial	%	51.75%	78.13%	95.66%
21=18+19	Total Rider J with increases - non-industrial	%	81.78%	99.31%	112.57%
22=18+20	Total Rider J with increases - industrial	%	78.13%	95.66%	108.92%

Notes:
1. Total Consolidated Retail Revenues at existing Base Rates include revenues from YEC and AEY's residential, general service and streetlight sales.

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 kWh/month and a general service customer using 2,000 kWh/month.

Table 4.3 summarizes Appendix 4.2 residential and commercial non-government bill impacts with the rate changes proposed in the Application, including the impact of proposed interim rates. In addition to the customer use levels assumed in Appendix 4.2 (1,000 kWh/month for residential and 2,000 kWh/month for commercial), Table 4.3 presents estimated bill impacts for average annual Yukon customer use assumed at 850 kWh/month for residential and 3,500 kWh/month with 15 kW demand for commercial.

In summary, estimated bill changes in Table 4.3 as of January 1, 2027 due to the Application are equal to about 34.3% of pre-2025/27 GRA bills. The bill impacts vary by customer class and consumption levels.

Table 4.3:
Application Bill Impacts for Residential & Commercial Non-Government Customers[13]

	Pre - GRA	2025-27 GRA			
	June 2025	July 2025 Interim	Jan 2026 Interim	Apr 2026 Final 2025 and 2026 plus true-up	Jan 2027 Final
	A	B	C	D	E
Monthly Bills					
Residential Non-Government, Whitehorse					
850 kWh/month consumption	$211.20	$232.28	$255.45	$271.64	$283.63
change from June 2025		*$21.08*	*$44.24*	*$60.44*	*$72.43*
change from June 2025		10.0%	20.9%	28.6%	34.3%
incremental change		10.0%	10.0%	6.3%	4.4%
1,000 kWh/month consumption	$243.84	$268.18	$294.92	$313.62	$327.46
change from June 2025		*$24.34*	*$51.08*	*$69.78*	*$83.62*
change from June 2025		10.0%	20.9%	28.6%	34.3%
incremental change		10.0%	10.0%	6.3%	4.4%
Commercial Non-Government, Whitehorse					
2,000 kWh/month consumption [5 kW demand]	$424.69	$467.07	$513.65	$546.22	$570.32
change from June 2025		*$42.39*	*$88.96*	*$121.53*	*$145.64*
change from June 2025		10.0%	20.9%	28.6%	34.3%
incremental change		10.0%	10.0%	6.3%	4.4%
3,500 kWh/month consumption [15 kW demand]	$903.41	$993.57	$1,092.66	$1,161.93	$1,213.22
change from June 2025		*$90.16*	*$189.25*	*$258.52*	*$309.81*
change from June 2025		10.0%	20.9%	28.6%	34.3%
incremental change		10.0%	10.0%	6.3%	4.4%

Note: The bills exclude AEY Rider R1 which is currently under review by YUB as per AEY submission.

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.

[13] Rate increase represents the technical definition of Revenue Shortfall as compared to the Total Consolidated Firm Sales Revenues at existing rates. Bill increases are shown as both incremental and cumulative. Incremental bill increases are the expected change in bills on the date of the bill adjustment as compared to the day before the bill adjustment. Cumulative bill increases are the change in bills on the date of the bill adjustment as compared to June 30, 2025, the day before the first interim rate change.

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 Yukon Energy's rate riders to flow through to Yukon Energy. Rate Schedule 42 includes a fixed Energy Charge of 8.298 cents per kWh that applies to all wholesale primary supply to AEY by Yukon Energy, and an Energy Reconciliation Adjustment (ERA) 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 Yukon Energy’s last GRA.

Following a two-part application regarding ERA matters filed by Yukon Energy in 2017, Board 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 kWh was approved effective June 1, 2011 as per Board 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 FOR JULY 1, 2025

Effective: 2025/07/01
Supersedes: 2024/10/01

RIDER J

NEW INTERIM RIDER J TO INCLUDE RECOVERY OF PORTION OF 2025-27 GRA 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 42 and Rate Schedule 43.

RATE: Rider J at 73.29% applicable to the base rates of the following rate classes to recover of a portion of the 2025-27 GRA 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 69.64% 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 42 and Rate Schedule 43.

APPENDIX 4.1B
RIDER J FOR JANUARY 1, 2026

Effective: 2026/01/01
Supersedes: 2025/07/01

RIDER J

NEW INTERIM RIDER J TO INCLUDE RECOVERY OF PORTION OF 2025-27 GRA 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 42 and Rate Schedule 43.

RATE: Rider J at 92.95% applicable to the base rates of the following rate classes to recover of a portion of the 2025-27 GRA 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 89.30% 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 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

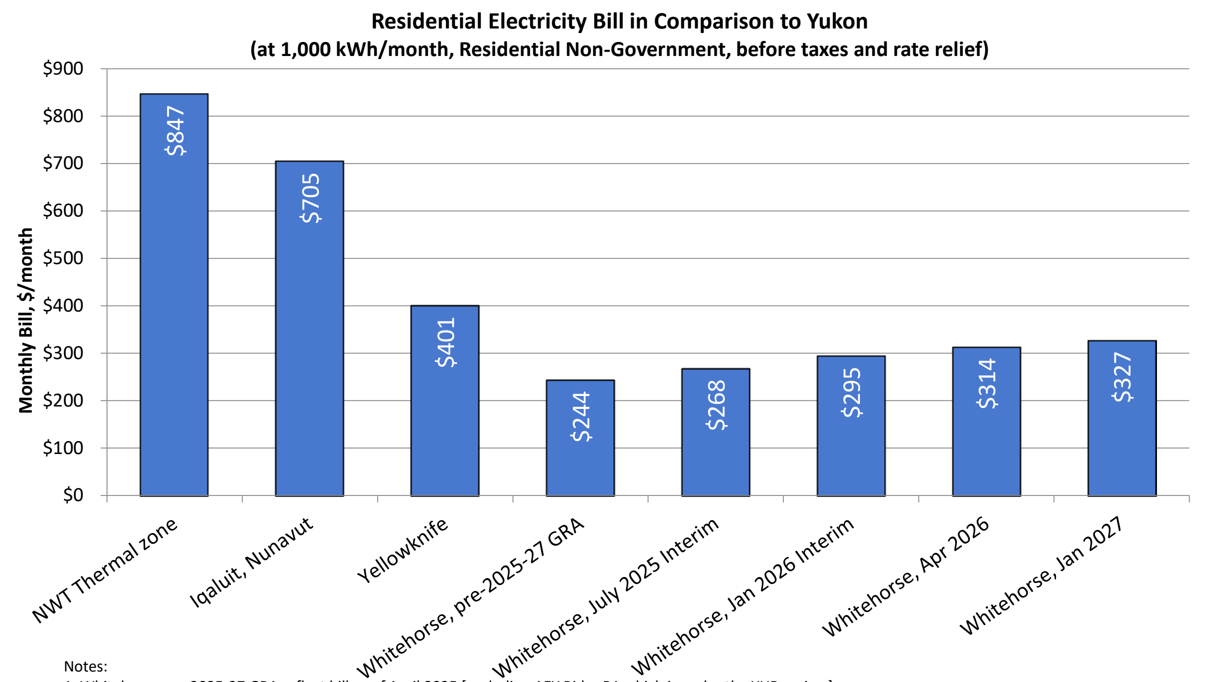
Table 4.2A-1:
Residential Electricity Bills in Comparison to Yukon
(1000 kWh/month consumption, Residential Non-Government, $)

1	NWT Thermal zone	$846.70
2	Iqaluit, Nunavut	$704.80
3	Yellowknife	$400.69
4	Edmonton, AB	$239.84
5	Whitehorse	$238.11
6	Calgary, AB	$231.69
7	Halifax, NS	$194.64
8	Charlottetown, PEI	$191.27
9	Regina, SK	$178.94
10	Toronto, ON	$169.70
11	Moncton, NB	$162.97
12	Ottawa, ON	$155.71
13	St. John's, NL	$146.20
14	Vancouver, BC	$120.58
15	Winnipeg, MB	$105.33
16	Montreal, QB	$80.48

Notes:

1. Monthly Bills are before taxes and rate relief [Hydro Quebec does not specify if the rate comparison includes rate relief].
2. Whitehorse bills as of March 2025 and include YEC Rider J [55.40%] and Rider J1 [9.45%], AEY Rider R [14.38%] and Rider R1 [-1.15%], Rider F and Rider E. The difference between the monthly bill of $238.11/month in this table and $243.8 in Figure 4.2A-1 and Table 4.2A-3 is the expiration of Rider F and Rider E effective April 1, 2025 and the exclusion of AEY Rider R1 in Figure 4.2A-1 and Table 4.2A-3 considering it is under YUB review at the time of preparation of the Application.
3. The monthly bills for Yellowknife are calculated using the rates in place as of March 2025. Available at https://www.nakapower.com/en-ca/customer-billing-rates/bill-calculator/northland-utilities-limited-yellowknife.html.
4. The monthly bills for NWT Thermal Zone are calculated using the rates as of March 2025. Available at https://www.ntpc.com/customer-service/residential-service/what-is-my-power-rate.
5. The monthly bills for Iqaluit are calculated using the territorial rates as of March 2025. Available at https://www.qec.nu.ca/customer-care/accounts-and-billing/customer-rates.
6. Bills for Toronto and Ottawa are based on Ontario Energy Board Bill Calculator [December 2024]. Available at https://www.oeb.ca/rates-and-your-bill/bill-calculator.
7. 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, 2024. Available at https://www.hydroquebec.com/data/documents-donnees/pdf/comparison-electricity-prices.pdf.

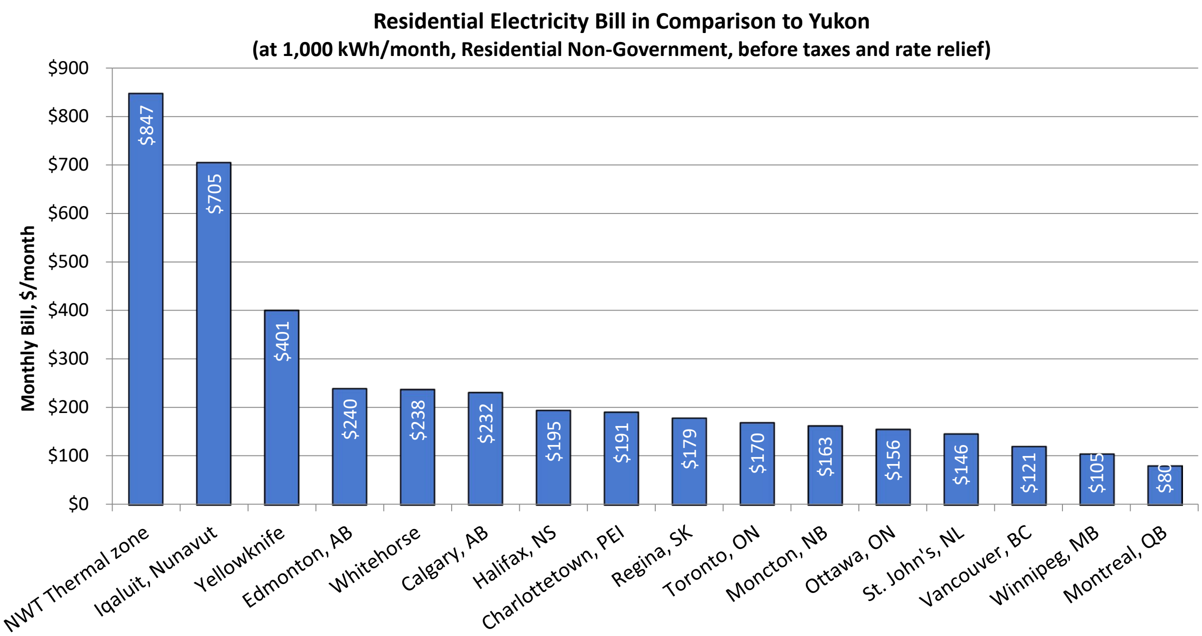
Figure 4.2A-1:[1]
Northern Residential Electricity Bill in Comparison to Yukon



Notes:
1. Whitehorse pre-2025-27 GRA reflect bill as of April 2025 [excluding AEY Rider R1 which is under the YUB review].
2. Bills for the northern utilities are based on rates as of March 2025.
3. Northwest Territories Power Corporation filed its 2024/25 and 2025/26 GRA asking for about 24% rate increase.
4. Qulliq Energy [Nunavut] filed 2025/26 GRA asking for a 14.1% rate increase effective April 1, 2025.

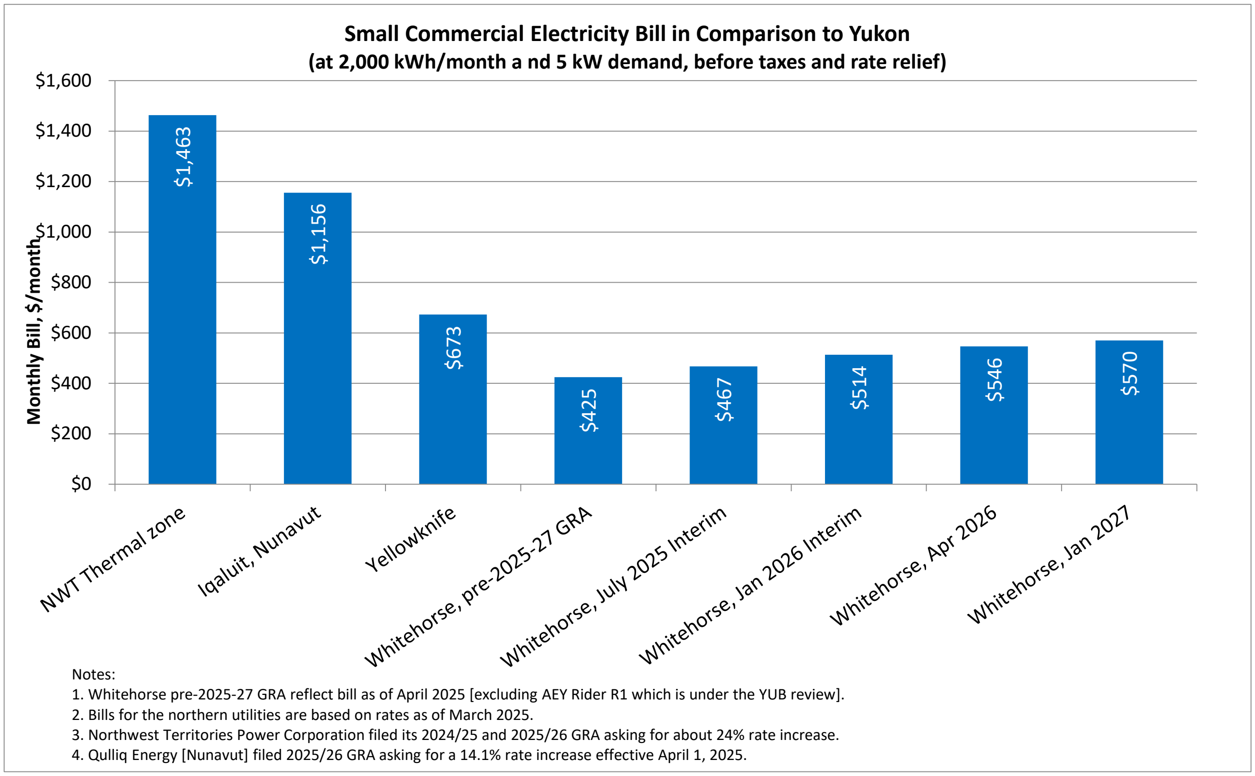
Figure 4.2A-2:[2]
Residential Electricity Bill in Comparison to Yukon

[1] Please see notes to Table 4.2A-1. Yukon proposed bills assume interim Rider J increase of 17.89% effective July 1, 2025, second interim Rider J increase of 19.66% effective January 1, 2026, 2025 and 2026 true-up effective April 1, 2026 and final 2027 rates effective January 1, 2027.
[2] Please see notes to Table 4.2A-1.



Notes:
1. Whitehorse monthly bill as of March 2025, includes fuel rider and true-up rider.
2. Bills for the northern utilities are based on rates as of March 2025.
3. Bills for all southern jurisdictions, except for Toronto and Ottawa, are based on Hydro Quebec bill comparison for April 2024.
4. Bills for Toronto and Ottawa are based on Ontario Energy Board Bill Calculator for rates as of December 2024 [Hydro Quebec report includes provincial rebate].

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



[3] Please see notes to Table 4.2A-1. Yukon proposed bills assume interim Rider J increase of 17.89% effective July 1, 2025, second interim Rider J increase of 19.66% effective January 1, 2026, 2025 and 2026 true-up effective April 1, 2026 and final 2027 rates effective January 1, 2027.

Table 4.2A-4:
Yukon Bills– Existing vs. Proposed - Non-Government Residential
(prior to consideration of subsidies, rebates and taxes)[4]

Line #	Customer Use per month:	1,000 kWh	April 2025 pre GRA		July 1, 2025 Interim		January 1, 2026 Interim		April 1, 2026 - 2025-26 final and true-up		2025-27 GRA Final Rate Jan 1, 2027 final	
			Rates	Bill [$/month]	Rates	Bill [$/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	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=KWh*Base rate	Second Block Energy (kWh)	-										
4=KWh*Rider F rate	Rider F (kWh)[Fuel Price Rider]		$0.0000	$0.00	$0.0000	$0.00	$0.0000	$0.00	$0.0000	$0.00	$0.0000	$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		55.40%	$75.37	73.29%	$99.71	92.95%	$126.45	92.95%	$126.45	112.57%	$153.15
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)		9.45%	$12.86	9.45%	$12.86	9.45%	$12.86	23.19%	$31.56	13.74%	$18.70
7=KWh*Rider E rate	Rider E (kWh) [LWRF Rider]		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8=(1+2+3)*Rider R rate	AEY Rider R (%)		14.38%	$19.56	14.38%	$19.56	14.38%	$19.56	14.38%	$19.56	14.38%	$19.56
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$243.8		$268.2		$294.9		$313.6		$327.5

Table 4.2A-5:
Yukon Bills– Existing vs. Proposed - Non-Government General Service
(prior to consideration of subsidies, rebates and taxes)[5]

[4] Excludes AEY Rider R1 which is under review by the Board.
[5] Excludes AEY Rider R1 which is under review by the Board.

Line #		2,000 kWh / 5 kW	April 2025 pre GRA		July 1, 2025 Interim		January 1, 2026 Interim		April 1, 2026 - 2025-26 final and true-up		Jan 1, 2027 final	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates											
1		Demand Charge (per kW per month)	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95
2=KWh*Base rate		First Block Energy (kWh)	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00
2a=KWh*Base rate		Second Block Energy (kWh)	$0.1288	$0.00	$0.1288	$0.00	$0.1288	$0.00	$0.1288	$0.00	$0.1288	$0.00
3=KWh*Rider F rate	Rider F (kWh)		$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00
4=(1+2)*Rider J rate	YEC Rider J (%)		55.40%	$131.27	73.29%	$173.66	92.95%	$220.23	92.95%	$220.23	112.57%	$266.73
5=(1+2)*Rider J1 rate	YEC Rider J1 (%)		9.45%	$22.39	9.45%	$22.39	9.45%	$22.39	23.19%	$54.96	13.74%	$32.57
6=KWh*Rider E rate	Rider E (kWh) [LWRF Rider]		$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00
7=(1+2)*Rider R rate	AEY Rider R (%)		14.38%	$34.07	14.38%	$34.07	14.38%	$34.07	14.38%	$34.07	14.38%	$34.07
8=Sum(1:7)	Total Before Tax Rebate, GST			$424.69		$467.07		$513.65		$546.22		$570.32

TAB 5
CAPITAL PROJECTS

5.0 CAPITAL PROJECTS

Capital project investments in rate base are generally grouped in one of two categories:

- Capital works on property, plant and equipment (including tangible and intangible); and
- Deferred cost studies (including new supply and other feasibility studies, studies required by regulation or relicensing, and dam safety works).

This section provides an overview of Yukon Energy's actual capital spending since the 2023/24 General Rate Application, including preliminary actuals for 2024, as well as forecast capital spending for 2025, 2026 and 2027. In response to changing capital cost conditions, the 2025-27 GRA defines "major" capital spending projects as having total costs over $2 million (prior GRA's defined major projects as having total costs over $1 million) and also reports on other projects with total costs in excess of $400,000 (prior GRA's reported on other projects with total costs in excess of $100,000).

1) **Overview of Capital Spending:** Provides a summary of Yukon Energy capital spending requirements from 2023 through 2027.

2) **Capital Works:** Reviews capital spending on property, plant and equipment (PP&E). This includes a detailed discussion of the major projects over $2 million that are forecast to be 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 $400,000 and up to $2 million that are forecast to be completed and included in rate base by 2027 are provided in Section 5.2.2 and Appendix 5.1B.

3) **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). Descriptions of deferred cost projects greater than $2 million that are forecast to be completed and included in rate base are provided in Section 5.3.1 and Appendix 5.2A. Descriptions of studies between $400,000 and up to $2 million that are forecast to be completed and included in rate base by 2027 are provided in Section 5.3.2 and Appendix 5.2B.

4) **Changes in Projects Reviewed and Approved in the 2023/24 GRA:** Capital projects reviewed and approved in the 2023/24 GRA with variances greater than $100,000 added to rate base for the 2025-27 GRA and emergent capital projects not forecast in the 2023/24 GRA with costs greater than $100,000 added to rate base for the 2025-27 GRA are provided in

Section 5.4. The current GRA includes actual capital costs for projects approved in the 2023/24 GRA (i.e., ratepayers are not paying for amounts estimated in the last GRA that did not materialize), and the Board by this review is able to assess any project capital cost increases in excess of $100,000 from previous approved amounts.

Tables 5.1 to 5.8 at the end of Tab 5 provide details of capital, deferred and intangible assets projects constructed since 2023 and forecasts for the 2025, 2026 and 2027 test years, including projects that have all of their costs remain as work in progress (WIP) at the end of 2027.

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. The Yukon and federal governments have identified goals to build net-zero economies by 2050. Yukon Energy is following a strategic road map of how Yukon's electricity system must evolve over the next 25 years to support this goal, while at the same time fulfilling our responsibility to provide safe and reliable electricity services to Yukoners. To meet the growing demands and future needs of the territory, significant and urgent investments are required in every aspect of the Yukon's electricity system in the next five years. This includes power generation, stability and storage, transmission and distribution, as well as end-use electrification. Yukon Energy estimates that more than $100 million per year in targeted capital infrastructure funding will be needed over the next five years. This investment will be spread throughout the territory and will support the three key pillars of Yukon Energy's Road Map,[1] which focuses on the following priorities for the next five years:

- An adequate and dependable supply of electricity;
- A strong electricity system; and
- Building tomorrow's plans and partnerships.

From 2025 to 2030, the planned work to build a robust and resilient grid will cost more than $550 million. More than 70% of that cost will go towards ensuring an adequate and dependable supply of electricity is available locally to meet growing demands for power, particularly in the winter.

[1]See Chapter 1 (Building a Resilient and Renewable Energy Future) of Yukon Energy's Road Map.

To keep electricity affordable and reduce the magnitude of our capital investments that may be passed on to ratepayers, Yukon Energy will need access to grant funding from all levels of government and affordable construction financing. Without this crucial investment, Yukon Energy risks not being able to deliver on the urgent infrastructure projects needed to build the foundation of a resilient energy future that Yukoners desire. Yukon Energy is also looking for options to develop innovative investment opportunities for First Nations governments and development corporations.

Yukon Energy continues to pursue capital grant funding from Federal and Territorial funding sources to reduce costs to ratepayers. However, funding has not been confirmed at this time, and there has been no capital funding provided in budgets released by Yukon Government. Yukon Energy is specifically pursuing Federal funding through its Smart Renewables and Electrification Pathways Program (SREPs) in multiple ways.

- Yukon Energy submitted an Expression of Interest for $50 million in December 2024 for the SREP Utility Stream, and was selected to submit a full project proposal by April 2, 2025. The April 2025 submission was for funding of approximately $25 million. Yukon Energy expects to apply for a further $25 million of funding later in 2025.

- Yukon Energy is working with Yukon Development Corporation (YDC) for funding support from the SREP Critical Regional Priorities Stream.

- Yukon Energy is working with YDC for funding specifically related to the Mayo Rock Slope Remediation and Surge Chamber projects. Yukon Energy officially submitted its registration to NRCan on April 2, 2025.

As Yukon Energy has no certainty regarding capital grant funding at this time, potential impacts of receiving funding that would offset Revenue Requirement have not been included in the GRA. Depending on the amount and timing of capital funding, it could have a significant impact on Yukon Energy's return. Yukon Energy will update the Board of the status of these funding applications throughout this regulatory process as information becomes available.

A multi-year, targeted capital infrastructure funding program is required by Yukon Energy to build and maintain the core electrical infrastructure that is needed in the Yukon now to meet growing demands for power and to ensure the safe and successful integration of additional community renewable electricity in the future. Over the next five years, the Yukon must urgently invest in projects that provide dependable winter capacity and demand-side management programs that will help alleviate pressure on the electricity system. With non-industrial electricity energy requirements projected to rise by 36% by 2030 and peak demands already increasing significantly, it's essential to secure reliable power sources to keep homes warm and lights on. As part of the road map, Yukon Energy intends to provide a reliable and resilient system by upgrading transmission and distribution networks, building new infrastructure, and incorporating energy storage solutions to maintain a stable electricity supply. Most importantly, a reliable and resilient system requires new sources of power generation that provide firm winter capacity. With these investments, the Yukon should have a dependable supply of energy and reserves to manage through extended periods of harsh winter weather or drought that limits the hydro supply.

With this context, Yukon Energy's capital spending from 2025 through 2027 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 and Strengthening the Power System:** Yukon Energy needs to reinvest in our hydroelectricity-generating assets and add more generation. Renewing aging infrastructure requires permitting, licensing, and significant maintenance. But investing in what we have enables us to continue to generate, on average, over 90% renewable electricity each year. Yukon Energy needs to keep up with critical maintenance while also upgrading systems, including increasing the capacity of the existing transmission lines, distribution lines, and substations to address expanding requirements. Yukon Energy also needs to implement technologies that give utilities greater understanding and control of the electricity needed and supplied every hour of every day. Spending in 2025 through 2027 focuses on projects planned to sustain or maintain the capability of the existing grid system ("sustaining capital projects"), including a number of enhancements or improvements to existing infrastructure.

- **Investment to Increase the Supply of Dependable Winter Power:** Demand for power in the Yukon is highest during the winter – in fact, it's nearly three times higher in winter than in summer. While the Yukon provides an abundance of hydro resources in the summer, there is not enough hydropower to meet peak demands in the middle of winter. We are in urgent need of electricity projects that can reliably provide capacity during the winter.

5.2 CAPITAL WORKS

This section reviews forecast rate base impacts from: (a) major capital works projects (projects with total cost over $2.0 million) undertaken by Yukon Energy since the 2023/24 GRA hearing and planned for 2025, 2026 and 2027; and (b) other ongoing capital projects costing between $400,000 and $2 million forecast undertaken by Yukon Energy since the 2023/24 GRA hearing and planned for 2025, 2026 and 2027.

5.2.1 Major Projects > $2 Million – Rate Base Additions

Test year spending on major capital works projects focuses on projects required to address sustaining capital requirements and strengthening the power system (i.e., required to replace or enhance/improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance) and expenditures to ensure sufficient dependable capacity for the integrated grid.

Total forecast to be added to year-end net rate base for the 2025-2027 test years, net of contributions but before depreciation impacts, for major capital works projects by the end of 2027 is approximately $286.3 million (see Table 5.8 at the end of Tab 5, $302.8 million cost offset by $16.5 million contributions) with $20 million out of $286.3 million included in the 2023/24 GRA rate base to net additions of $266.3 million. Each major project forecast to be added to rate base is identified below:

- **Spending to address the Supply of Dependable Winter Power** – Net rate base impact of approximately $79.0 million, excluding any depreciation or amortization deductions and before total contributions of $16.5 million for the Battery Energy Storage System, as summarized in the table that follows:

Table 5.2-1:
Dependable Winter Power Supply Projects >$ 2 Million Added to Rate Base

Project	Forecast Cost ($M)	In-service
Thermal Replacement (16.5 MW) *	$44.044M	2025
Battery Energy Storage System	$34.957M	2026

* The 2023/24 GRA assumed $18.18 million of the Thermal Replacement Project was to be closed and included in rate base in 2024. The total additions of $62.219 million since its start is shown in Table 5.8 at the end of Tab 5, resulting in the increase $44.044 million compared to the 2023/2024 GRA approved amount.

- **Spending on Sustaining Capital and Strengthening the Power System -** Net rate base impact of approximately $201.5 million as summarized in the table that follows:

Table 5.2-2:
Sustaining Capital/Strengthening Power System Projects >$ 2 Million Added to Rate Base

Project	Forecast Cost ($M)	In-service
MH0 Rockslide Stabilization and Remediation	$78.645M	2026
Wareham Dam Spillway	$73.924M	2027
MH0 Surge Chamber Replacement	$27.831M	2026
Transmission Line Refurbishment L178	$6.500M	2025/26/27
Dawson Voltage Conversion – Phase 2*	$3.921M	2025
Transmission Line Hazard Tree Reduction and ROW Widening	$2.850M	2025/26/27
Spare Power Transformer Program	$2.675M	2027
Dam Safety Review Mitigations	$2.600M	2025/26/27
WH3 Head Gate Replacement	$2.535M	2025

* The initial phase of the Dawson Voltage Conversion was approved in the 2023/24 GRA. Forecast costs of $1.872 million were added to rate base in 2024. The total additions of $5.793 million since its start is shown in Table 5.8 at the end of Tab 5, resulting in the increase of $3.921 million compared to the 2023/24 GRA approved amount.

- **Spending on Overhauls** – Net rate base impact of approximately $2.1 million:

Table 5.2-3:
Overhaul Project >$ 2 Million Added to Rate Base

Project	Forecast Cost ($M)	In-service
WH3 10-Year Overhaul	$2.050M	2027

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 $400,000 to $2 Million – Rate Base Additions

Forecast net rate base additions (after contributions, and before depreciation or amortization deductions) from 2025 through 2027 for PP&E projects with rate base amounts between $400,000 and $2 million total approximate $32.9 million (see Table 5.8 at the end of Tab 5, excluding RFID and RFSR).

Business case summaries for each of the projects included in Tables 5.2 to 5.6 at the end of Tab 5 with rate base additions between $400,000 and $2 million that come into service between 2025 and 2027 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 $400,000 for overhauls, right of use assets, RFID, and reserve for site restoration.

- **Generation Projects** –The total forecast 2025 through 2027 rate base increase from generation projects approximates $7.8 million, excluding any depreciation or amortization deductions. Rate base additions relate to the projects outlined in Table 5.2-4:

Table 5.2-4:
Generation Projects >$400,000 and< $2 Million Added to Rate Base

Project	Forecast Cost ($M)	In-service
Lewes River Boat Lock	$1.640M	2025
Critical Spare Parts – Hydro Generation Units	$1.650M	2025/26/27
WHS West Gate Refurbishment	$1.100M	2027
Whitehorse Spillway Stoplog Refurbishment*	$0.952M	2025
WHS East Gate Refurbishment	$0.908M	2026
Aishihik Canyon Control Structure Instrumentation, Control and Communications	$0.650M	2026
MBH0 Cooling Circuit	$0.460M	2027
Aishihik Elevator Modernization	$0.400M	2027

* The 2023/24 GRA assumed $1.0 million of the Whitehorse Spillway Stoplog Refurbishment project was to be closed and included in rate base in 2024. The total additions since its start of $1.952 million is shown in Table 5.8 at the end of Tab 5, resulting in an increase of $0.952 million compared to the 2023/24 GRA amount.

- **Transmission Projects** – The total forecast 2025 through 2027 rate base increase from transmission projects approximates $6.5 million, excluding any depreciation or amortization deductions. Rate base additions relate to the projects in Table 5.2-5:

Table 5.2-5:
Transmission Projects >$400,000 and< $2 Million added to Rate Base

Project	Forecast Cost ($M)	In-service
Protection, Control, and SCADA Upgrade – WH4	$1.333M	2026
Protection, Control and SCADA Upgrade – S150	$1.300M	2027
Transmission Line Test and Treat Program	$0.963M	2025/26/27
T250-30 Silver King Transformer Replacement	$0.880M	2026
AH0 Switchgear Breaker Replacement	$0.780M	2027
Transmission Structure Replacement Program	$0.750M	2025/26/27
Protection and Control Upgrade – S249 Breaking Resistor	$0.450M	2026

- **Distribution Projects** – The total 2025 through 2027 rate base increase from distribution projects approximates $4.9 million, excluding any depreciation or amortization deductions and before total contributions of approximately $1.2 million. Rate base additions relate to the projects in Table 5.2-6:

Table 5.2-6:
Distribution Projects >$400,000 and< $2 Million Added to Rate Base

Project	Forecast Cost ($M)	In-service
Customer Extensions	$1.800M	2025/26/27
Distribution Pole and Transformer Replacement Program	$1.050M	2025/26/27
Grid Modernization Program	$0.700M	2026/27
South Fox Lake PT Upgrade	$0.458M	2025
Distribution Upgrades Program	$0.450M	2025/26/27
Mendenhall PT Upgrade	$0.400M	2025

- **General Plant and Equipment** –Total 2025 through 2027 rate base increase from general plant and equipment projects approximates $6.2 million, excluding any depreciation or amortization deductions. Rate base additions relate to the projects in Table 5.2-7:

**Table 5.2-7:
General Plant and Equipment Costs >$400,000 and< $2 Million Added to Rate Base**

Project	Forecast Cost ($M)	In-service
Vehicle Purchases	$1.875M	2025/26/27
Building Condition Report Refurbishments	$1.200M	2025/26/27
Crane Refurbishment Program	$1.150M	2025/26/27
Fish Ladder TWG Recommendations Implementation	$0.543M	2025
SCADA Upgrade Program	$0.530M	2025/26/27
Computer Replacements	$0.480M	2025/26/27
Central Storeroom for Generation Parts	$0.400M	2026

- **Overhauls** – The total 2025 through 2027 rate base increase from overhauls approximates $7.8 million, excluding any depreciation or amortization deductions. Rate base additions relate to the projects in Table 5.2-8:

**Table 5.2-8:
Overhauls >$400,000 and <$2 Million Added to Rate Base**

Project	Forecast Cost ($M)	In-service
MBH1 Overhaul	$1.600M	2026
MBH2 Overhaul	$1.597M	2025
WG1 30,000 Hour Overhaul	$1.520M	2025
WG3 30,000 Hour Overhaul	$1.520M	2026
DD4 Overhaul	$0.975M	2025
WG0 Major Plant Overhaul	$0.560M	2025

- **Intangible Assets** – The total 2025 through 2027 rate base increase from intangible assets costs approximates $1.2 million, excluding any depreciation or amortization deductions. Rate base additions relate to the projects in Table 5.2-9:

**Table 5.2-9:
Intangible Assets >$400,000 and< $2 Million Added to Rate Base**

Project	Forecast Cost ($M)	In-service
Gates Certification Program	$1.228M	2025/26/27

- **Right of Use Assets** –There are no planned 2025 through 2027 rate base additions.
- **Reserve for Injuries & Damages (RFID)** – A review of forecast costs is provided in Tab 3 of the Application, Section 3.3.6.2.
- **Reserve for Site Restoration (RFSR)** – A brief review of this deferral account is provided in Tab 3 of the Application, Section 3.4.5, which also shows there are no planned costs during the test year.

5.2.3 Capital Projects Remaining in Work-in-Progress

Board Order 2024-05, paragraph 17 states: "Secondly, regarding the GRA process, if an applicant is to incur charges in CWIP, even if the project will not be capitalized in the current application test years, the application must contain more information on those projects than just the name of the project and the dollar amount…" Capital projects planned to be in progress with forecast costs greater than $400,000 that will not be capitalized or added to rate base in the current application test years are identified below and detailed in Appendix 5.4A.

Table 5.2-10:
Capital Projects >$0.400 Million Remaining in WIP

Project	Forecast 2027 WIP ($M)
Whitehorse Power Expansion	$54.200M
Wareham Dam Spillway – Full Replacement	$11.523M
PLT Shop	$5.500M
Mayo MH0 Plant Renewal	$3.500M
WRGS Office Building	$3.500M
Carmacks Substation Relocate	$3.250M
WH1 Uprate	$2.250M
Renewable Resource Projects	$0.900M
EV Infrastructure Transition	$0.660M
ERP Replacement	$0.618M
P126 Building Renovation	$0.600M
T9 Transformer Critical Spare	$0.460M
Protection and Control - S170	$0.453M
Protection and Control - WD0	$0.400M

5.3 DEFERRED COSTS

This section reviews: (a) major deferred cost projects (projects over $2 million); and (b) other deferred cost projects between $400,000 and $2 million, undertaken by Yukon Energy since the 2023/24 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 reviews).

As described in Section 3.1.8, as part of the 2023/24 General Rate Application, the Board in Board Order 2024-05 paragraph 312 stated:

> "… *To reduce the impacts of capitalizing significant amounts of AFUDC on ratepayers, the Board directs YEC to examine and redefine its processes for similar major deferred capital projects and to only capitalize those costs once it is determined that there is a reasonable probability that that project will go forward and to reflect, as necessary, any changes that may be required to YEC's capitalization policies and supporting documents. On a go-forward basis, YEC is to explore and provide an alternative for the treatment of costs incurred for such projects until it has established a reasonable probability that the project will proceed. For example, this could be done by expensing the costs as incurred (until a reasonable probability of proceeding is determined) or treating the costs as no-cost capital (with or without debt and/or equity financing)*."

Yukon Energy performed a comprehensive review of its capitalization policies and has developed a new policy based on extensive research of International Financial Reporting Standards (IFRS) and industry guidance. Effective January 1, 2025, Yukon Energy has implemented the policy FX-001 Criteria for Capitalization. A copy of this policy has been provided in Appendix 5.3. In summary, this policy complies with IFRS standards and requires that costs that do not meet the capitalization criteria be expensed. As a result, no new projects will be capitalized (as costs will no longer meet the capitalization criteria) and the category of Feasibility Studies will cease to exist in the future. As this is a policy change, there will be a transition period. Yukon Energy will continue to include Feasibility Studies in this GRA that were included in the 2023/24 GRA. These projects will continue as Feasibility work-in-progress until completion, at which time they will be amortized over the appropriate period until fully amortized.

Deferred expenditures in WIP during 2025 through 2027, and not affecting rate base until after 2027, are detailed in Section 5.3.3).

5.3.1 Major Deferred Projects >$2 Million – Rate Base Additions

The total forecast cost to be added to net rate base for major deferred cost projects for 2025 through 2027 is approximately $34.2 million. Each major project added to rate base is reviewed separately in Appendix 5.2A (see also Tables 5.3 to 5.8 at the end of Tab 5):

- **Spending on Licensing Projects** – Net rate base impact of approximately $29.9 million, excluding reductions due to amortization, relate to the projects in Table 5.3-1:

Table 5.3-1:
Licensing Project Costs >$2 Million Added to Rate Base

Project	Forecast Cost ($M)	In-service
WRGS Long-Term Water Use License Renewal	$10.608M	2025
AGS 25-Year Water Use License Renewal	$9.770M	2027
MGS 5-Year Water Use License Renewal	$7.295M	2025
Mayo Lake Enhanced Storage	$2.267M	2024

- **Spending on Regulatory Requirements** – Net rate base impact of approximately $2.3 million, excluding reductions due to amortizations, relate to the projects in Table 5.3-2:

Table 5.3-2:
Regulatory Costs >$2 Million Added to Rate Base

Project	Forecast Cost ($M)	In-service
Integrated Resource Plan	$2.332M	2025

Business case summaries for each of the above major deferred projects added to rate base in this GRA are reviewed in Appendix 5.2A.

5.3.2 Deferred Projects between $0.4 million and $2 Million – Rate Base Additions

The total increase to rate base in 2025 through 2027 from deferred cost activities for the projects between $0.4 million and $2.0 million is approximately $2.4 million (excluding reductions due to amortizations).

Appendix 5.2B summarizes deferred cost projects over $400,000 but less than $2 million that will be added to rate base in the test years. Details on project costs are summarized in Tables 5.3 to 5.8 at the end of Tab 5. Rate base additions from 2025 to 2027 in each deferred cost activity totaling between $400,000 and $2 million that impact 2025 through 2027 rate base are summarized below.

- **Licensing**: Rate base additions of approximately $0.7 million as outlined in Table 5.3-3:

Table 5.3-3:
Licensing Costs >$0.400 Million and < $2 Million Added to Rate Base

Project	Forecast Cost ($M)	In-service
AGS 5-Year Fisheries Act Authorization	$0.714M	2025

- **Regulatory Requirements**: Rate base additions of approximately $1.7 million as outlined in Table 5.3-4:

Table 5.3-4:
Regulatory Costs >$0.400 Million and < $2 Million Added to Rate Base

Project	Forecast Cost ($M)	In-service
Demand Side Management	$1.675M	2025/26/27

The GRA related costs in Table 5.8 at the end of Tab 5 reflect spending forecasts over 2025-27 years which remain in WIP. Cost awards, once approved by the Board, are transferred to the Hearing Reserve Account. Tab 3, Table 3.13.1.2 provides the forecast additions to the reserve account based on assumed cost awards.

Business case summaries for each of the above deferred projects added to rate base in this GRA are reviewed in Appendix 5.2B.

5.3.3 Deferred Projects Remaining in Work-in-Progress

Board Order 2024-05, paragraph 17 states: "Secondly, regarding the GRA process, if an applicant is to incur charges in CWIP, even if the project will not be capitalized in the current application test years, the application must contain more information on those projects than just the name of the project and the dollar amount…" Deferred projects planned to be in progress with forecast costs greater than $400,000 that will not be capitalized or added to rate base in the current application test years are identified below and detailed in Appendix 5.4B.

Table 5.3-5:
Deferred Projects >$0.400 Million and < $2 Million in WIP

Project	Forecast WIP ($M)
Atlin Hydro SIS and EPA	$1.782M

5.4 CHANGES IN PROJECTS REVIEWED AND APPROVED IN THE 2023/24 GRA

This section reviews projects with actual costs that vary from costs approved in the 2023/24 GRA. Board Order 2024-05, paragraph 250 stated: "When YEC requests these capital projects to be added to its rate base, all actual costs incurred and the prudency thereof, will be examined further. YEC is reminded that the Board will expect YEC to file sufficient detail respecting its forecast and actual costs for each such capital project and to include all variance explanations where actual costs are different from those approved on a forecast basis in this Board Order."

Projects included in the 2023/24 GRA included forecast costs for some projects that were not yet completed. The opening 2025 rate base includes adjustments to reflect actual costs to these projects. Capital projects reviewed and approved in the 2023/24 GRA with variances greater than $100,000 added to rate base for the 2025-27 GRA are summarized in the table below and detailed in Appendix 5.5.

Table 5.4-1:
Approved Projects with Variances greater than $100,000 Added to Rate Base

Project	2023/24 GRA Approved Cost ($M)	2025-27 GRA Updated Cost ($M)	Increase to Rate Base
Vehicle Purchases (2024)	$0.567M	$0.890M	$0.323M
HQ Datacentre Server Replacement	$0.300M	$0.492M	$0.192M
Wareham Spillway Concrete Repair	$0.500M	$0.937M	$0.437M
Schwatka Lake Safety/Debris Boom	$1.097M	$1.220M	$0.123M

In addition, Yukon Energy incurred costs on projects that were not forecast in the 2023/24 GRA. These emergent projects are included in the opening 2025 rate base. Capital projects not forecast in the 2023/24

GRA with costs greater than $100,000 added to rate base for the 2025-27 GRA are summarized in the table below and detailed in Appendix 5.5:

Table 5.4-2:
Projects Not Forecast in the 2023/24 GRA >$0.100 Million Added to Rate Base

Project	2023/24 GRA Approved Cost ($M)	2025-27 GRA Updated Cost ($M)	Increase to Rate Base
Mobile Diesel Generators	$0	$0.749M	$0.749M
WD7 Generator Reconditioning	$0	$0.109M	$0.109M
Aishihik Intake Inspection	$0	$0.158M	$0.158M
L171 Structure Replacement	$0	$0.259M	$0.259M
Load Bank and Transformers	$0	$1.723M	$1.723M
Tailrace Gate Certifications	$0	$0.552M	$0.552M
Mayo Bucket Truck	$0	$0.362M	$0.362M
Mayo Digger	$0	$0.454M	$0.454M

YEC 2025-27 GRA **Table 5.1**
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT - SUMMARY **MAY 2025**
($000S)

Description	Forecast 2023	Forecast 2024	Actual 2023	Prem Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
SUMMARY - RECONCILIATION OF PROPERTY, PLANT AND EQUIPMENT							
Work in Progress (WIP), Beginning of Year	33,638	76,525	38,199	70,013	91,995	107,372	67,485
Transfers							
WIP Beginning of Year	33,638	76,525	38,199	70,013	91,995	107,372	67,485
Total Major Projects	60,264	89,663	58,040	34,297	88,304	103,387	108,450
Ongoing Maintenance Capital							
Generation	520	1,560	2,166	3,076	3,649	3,129	4,245
Transmission	1,104	1,179	490	2,788	2,209	4,646	3,323
Distribution	1,300	1,005	1,934	2,085	1,210	1,625	1,900
General Plant & Equipment	2,596	2,872	2,531	3,532	3,135	3,410	3,605
Right of Use Assets	750	0					
Overhaul	0	400	691	610	4,570	3,045	0
Intangibles	435	630	428	1,210	1,985	815	765
RFID	554	682	555	2,420	554	554	554
RFSR	723	0	605	0	0	0	0
Subtotal Ongoing Capital	7,982	8,328	9,400	15,720	17,312	17,224	14,392
Total Expenditures	68,246	97,991	67,440	50,017	105,616	120,610	122,842
Transfer to RFID/RFSR	-1,277	-682	-1,160	-2,420	-554	-554	-554
Other Adjustments							
Total WIP Adjustments and Transfers	-1,277	-682	-1,160	-2,420	-554	-554	-554
Transfer to Ratebase	-24,082	-56,941	-34,465	-25,616	-89,685	-159,943	-99,619
WIP end of year	**76,525**	**116,893**	**70,013**	**91,995**	**107,372**	**67,485**	**90,154**
Opening PPE in-service	701,616	722,507	697,055	726,710	751,115	838,813	997,865
Net transfer from WIP	22,561	52,111	34,365	24,406	87,700	159,053	98,779
Retirements and other adjustments	-1,671	-2	-4,710	-2	-2	-2	-2
Closing PPE in-service	**722,507**	**774,616**	**726,710**	**751,115**	**838,813**	**997,865**	**1,096,643**
Opening Total PPE (in-service plus WIP)	735,254	799,031	735,254	796,724	843,110	946,185	1,065,350
Change to total PPE	63,777	92,478	61,469	46,386	103,076	119,165	121,446
Closing total PPE	**799,031**	**891,509**	**796,724**	**843,110**	**946,185**	**1,065,350**	**1,186,796**
RECONCILIATION OF CUSTOMER CONTRIBUTIONS							
Opening Customer Contributions WIP	**12,788**	**21,504**	**12,788**	**18,337**	**12,933**	**16,670**	**170**
Customer Contributions Received	10,587	6,447	11,182	3,012	4,137	400	400
Adjustments							
less: transfer to Rate Base	-1,870	-1,436	-5,633	-8,415	-400	-16,900	-400
Customer Contributions WIP end of year	**21,504**	**26,516**	**18,337**	**12,933**	**16,670**	**170**	**170**
Opening Gross Customer Contributions in Service	**234,687**	**236,558**	**234,687**	**239,968**	**248,384**	**248,784**	**265,684**
Transfers from WIP	1,870	1,436	5,633	8,415	400	16,900	400
Retirements, Disposals and Adjustments	0	0	-353	0	0	0	0
Closing Gross Customer Contributions in Service	**236,558**	**237,993**	**239,968**	**248,384**	**248,784**	**265,684**	**266,084**
Opening Total Contribution (in-service plus WIP)	247,475	258,062	247,475	258,305	261,316	265,453	265,853
Change to total Contribution	10,587	6,447	10,830	3,012	4,137	400	400
Closing total Contribution	258,062	264,509	258,305	261,316	265,453	265,853	266,253

YEC 2025-27 GRA **Table 5.2A**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2023 Approved **MAY 2025**
($000S)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Capital Projects – Major projects > $1 million				
Generation				
Thermal Replacement (16.5 MW)	6,297.3	28,650.0	0.0	34,947.3
MH0 Road & Road Slope Stability	934.4	828.1	0.0	1,762.5
Schwatka Lake Safety/Debris Boom	581.2	515.5	0.0	1,096.8
Wareham Spillway Concrete Repair	0.0	500.0	-500.0	0.0
2023 Mayo-Faro Diesel Infrastructure	0.0	5,289.7	-5,289.7	0.0
Pumped Storage	72.5	2.0	0.0	74.5
Energy Storage System	10,000.7	5,781.8	0.0	15,782.5
MH0 Surge Chamber Replacement	324.5	1,000.0	0.0	1,324.5
Lewes River Boat Lock	64.3	450.0	0.0	514.3
MH0 rockslide Stabilization and Remediation	0.0	2,500.0	0.0	2,500.0
Mayo Civil/Structural Infrastructure Program	0.0	200.0	0.0	200.0
Transmission				
Whitehorse Interconnection	8,403.9	2,295.0	0.0	10,698.9
Transmission Line Replacement L178	0.0	1,000.0	-1,000.0	0.0
P&C: S250 Callison Protection, Control and SCADA Upgra	388.1	1,736.8	0.0	2,124.9
Distribution				
Dawson Voltage Conversion	71.8	600.0	0.0	671.8
IPP Connections	3,705.3	2,453.9	-176.0	5,983.3
General Plant				
Whitehorse Stoplog Crane Replacement	322.8	2,145.2	0.0	2,467.9
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
Intangible Assets				
PAMMS Asset Management Framework	4,455.2	1,011.0	-5,466.2	0.0
ERP Replacement	99.8	75.0	0.0	174.8
Subtotal	**35,752.8**	**60,264.1**	**-15,692.8**	**80,324.0**
Deferred Costs – Major projects > $1 million				
Licensing				
Mayo Lake Storage (see also P11-073)	4,541.4	110.0	0.0	4,651.4
Aishihik 5-Year License Renewal	575.4	40.0	0.0	615.4
Aishihik 25-Year License Renewal	5,734.9	811.2	0.0	6,546.1
Whitehorse Water Use License Renewal	2,120.0	5,817.9	0.0	7,937.8
MGS Water Use License Renewal	94.2	3,500.0	0.0	3,594.2
Regulatory				
Atlin Hydro SIS and EPA	1,474.2	134.5	0.0	1,608.7
DSM Program 2022-2030	0.0	1,271.6	-1,271.6	0.0
2024 Resource Plan	0.0	400.0	0.0	400.0
Subtotal	**14,540.1**	**12,085.2**	**-1,271.6**	**25,353.7**
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
Lewes Gate/Seal Refurbishment	149.2	0.0	0.0	149.2
Other Projects with <$100k Spending	78.1	245.0	-255.7	67.4
Subtotal	**238.1**	**520.0**	**-541.4**	**216.7**

YEC 2025-27 GRA Table 5.2A
WORK IN PROGRESS CONTINUITY SCHEDULE - 2023 Approved MAY 2025
($000S)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
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
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**	**1,103.6**	**-1,017.7**	**405.0**
Distribution				
Customer Extensions	1,127.1	600.0	-1,727.1	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	**1,543.3**	**1,300.0**	**-2,843.3**	**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**
Intangible Assets – Projects $100,000 to $1 million				
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**
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**
Deferred Costs – Projects $100,000 to $1 million				
Mayo Civil Infrastructure Refurbishment Planning	168.4	0.0	-168.4	0.0
System Wide Arc Flash Study	147.7	50.0	-197.7	0.0
IPP Standing Offer Program Implementation	70.3	0.0	-70.3	0.0
System Wide Stability Study	0.0	200.0	-200.0	0.0
Renewable Diesel Pilot Project	0.0	25.0	0.0	25.0
Skagway Shoreside Power	0.0	100.0	0.0	100.0
WRGS Thermal Assessment & Permitting	0.0	413.0	0.0	413.0
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)	253.9	131.7	-385.6	0.0
GRA 2023-2024 (Hearing Reserve Acct)	0.0	250.0	0.0	250.0
Other Projects with <$100k Spending	23.1	344.0	-342.2	25.0
Subtotal	**663.5**	**1,513.8**	**-1,364.2**	**813.0**
Total	**53,402.5**	**80,567.8**	**-26,718.0**	**107,252.4**
Capital Projects Contributions – Major projects > $1 million				
Energy Storage System Contributions	-7,026.1	-3,847.9	0.0	-10,874.0
IPP Connections Customer Contributions	-4,900.9	-1,498.0	176.0	-6,222.9
Lewes River Boat Lock Insurance Proceeds	0.0	-4,407.5	0.0	-4,407.5
Subtotal	-11,927.0	-9,753.4	176.0	-21,504.4
Capital Projects Contributions – Projects $100,000 to $1 million				
Customer Extensions Customer Contributions	-860.7	-400.0	1,260.7	0.0
L177 Re Route Contributions	0.0	-433.6	433.6	0.0
Subtotal	-860.7	-833.6	1,694.3	0.0

YEC 2025-27 GRA **Table 5.2A**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2023 Approved **MAY 2025**
($000S)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Deferred Costs Contributions – Major projects > $1 million				
DSM Program Development Contributions	0.0	-21.6	21.6	0.0
Atlin Hydro SIS and EPA Contributions	-288.5	-67.2	0.0	-355.8
Subtotal	-288.5	-88.9	21.6	-355.8
Total	**-13,076.3**	**-10,675.8**	**1,891.9**	**-21,860.2**
Total Major Projects	35,752.8	60,264.1	-15,692.8	80,324.0
Capital Projects – Projects $100,000 to $1 million				
Total Generation	238.1	520.0	-541.4	216.7
Total Transmission	319.1	1,103.6	-1,017.7	405.0
Total Distribution	1,543.3	1,300.0	-2,843.3	0.0
Total General Plant & Equipment	339.6	2,596.1	-2,795.6	140.0
Right of Use Assets	0.0	750.1	-750.1	0.0
Total Overhaul	0.0	0.0	0.0	0.0
Total Intangible Assets	6.1	435.0	-441.1	0.0
Total Capital Projects	38,198.9	66,968.9	-24,082.1	81,085.7
Total Deferred Costs	15,203.6	13,599.0	-2,635.9	26,166.7
Total Contributions				
Total Capital Contributions	-12,787.7	-10,586.9	1,870.3	-21,504.4
Total Deferred Cost Contributions	-288.5	-88.9	21.6	-355.8
RFID				
RFID	345.9	554.0	-899.9	0.0
Total Net RFID	**345.9**	**554.0**	**-899.9**	**0.0**
Reserve for Site Restoration				
Reserve for Site Restoration Bucket	40.1	723.0	-763.1	0.0
Total Net RFSR	**40.1**	**723.0**	**-763.1**	**0.0**

YEC 2025-27 GRA **Table 5.2B**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2024 Approved **MAY 2025**
($000S)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Capital Projects – Major projects > $1 million				
Generation				
Thermal Replacement (16.5 MW)	34,947.3	22,556.7	-18,175.5	39,328.5
MH0 Road & Road Slope Stability	1,762.5	111.9	-1,874.4	0.0
Schwatka Lake Safety/Debris Boom	1,096.8	0.0	-1,096.8	0.0
2023 Mayo-Faro Diesel Infrastructure	0.0	410.3	-410.3	0.0
Whitehorse Spillway Stoplog Refurbishment	0.0	1,000.0	-1,000.0	0.0
Pumped Storage	74.5	250.0	0.0	324.5
Energy Storage System	15,782.5	15,168.2	0.0	30,950.7
MH0 Surge Chamber Replacement	1,324.5	3,000.0	0.0	4,324.5
Lewes River Boat Lock	514.3	15,000.0	0.0	15,514.3
MH0 rockslide Stabilization and Remediation	2,500.0	9,500.0	0.0	12,000.0
Mayo Civil/Structural Infrastructure Program	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
AH1 and AH2 Governor Upgrades	0.0	200.0	0.0	200.0
Lewes Gate Automation	0.0	250.0	0.0	250.0
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
Lewes River Boat Lock Road Access Rebuild	0.0	1,200.0	0.0	1,200.0
Transmission				
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
P&C: S250 Callison Protection, Control and SCADA Upgrac	2,124.9	0.0	-2,124.9	0.0
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
Faro 870S and S140 Substation Interconnection	0.0	400.0	0.0	400.0
Distribution				
Dawson Voltage Conversion	671.8	1,200.0	-1,871.8	0.0
IPP Connections	5,983.3	547.4	-1,035.6	5,495.1
General Plant				
Whitehorse Stoplog Crane Replacement	2,467.9	1,778.8	-4,246.7	0.0
P126 Building Renovation	0.0	500.0	0.0	500.0
Overhaul				
AH3 Overhaul	0.0	2,200.0	-2,200.0	0.0
Intangible Assets				
ERP Replacement	174.8	4,200.0	0.0	4,374.8
Subtotal	**80,324.0**	**89,663.2**	**-50,234.7**	**119,752.6**
Deferred Costs – Major projects > $1 million				
Licensing				
Mayo Lake Storage (see also P11-073)	4,651.4	110.0	0.0	4,761.4
Aishihik 5-Year License Renewal	615.4	189.0	-804.4	0.0
Aishihik 25-Year License Renewal	6,546.1	1,427.8	0.0	7,973.9
Whitehorse Water Use License Renewal	7,937.8	2,500.0	0.0	10,437.8
MGS Water Use License Renewal	3,594.2	3,100.0	0.0	6,694.2
Regulatory				
Atlin Hydro SIS and EPA	1,608.7	0.0	0.0	1,608.7
DSM Program 2022-2030	0.0	1,160.0	-1,160.0	0.0
2024 Resource Plan	400.0	1,600.0	0.0	2,000.0
Subtotal	**25,353.7**	**10,086.8**	**-1,964.4**	**33,476.1**

YEC 2025-27 GRA **Table 5.2B**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2024 Approved **MAY 2025**
($000S)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions				
Generation				
Lewes Gate/Seal Refurbishment	149.2	200.0	0.0	349.2
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
MBH1/MBH2 LP/HP Oil Supply System replacement	0.0	150.0	0.0	150.0
Other Projects with <$100k Spending	67.4	210.0	-75.0	202.4
Subtotal	**216.7**	**1,560.0**	**-1,075.0**	**701.7**
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
P&C: DD0 Exciter, Governor and Load Sharing	0.0	100.0	0.0	100.0
Other Projects with <$100k Spending	0.0	145.0	-145.0	0.0
Subtotal	**405.0**	**1,179.0**	**-1,484.0**	**100.0**
Distribution				
Customer Extensions	0.0	600.0	-600.0	0.0
Carmacks Substation Relocate	0.0	250.0	0.0	250.0
Other Projects with <$100k Spending	0.0	155.0	-155.0	0.0
Subtotal	**0.0**	**1,005.0**	**-755.0**	**250.0**
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
Central Storeroom for Generation Parts	0.0	400.0	0.0	400.0
Other Projects with <$100k Spending	0.0	800.0	-800.0	0.0
Subtotal	**140.0**	**2,872.0**	**-2,612.0**	**400.0**
Overhaul				
WG3 Overhaul	0.0	400.0	-400.0	0.0
Intangible Assets – Projects $100,000 to $1 million				
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
Project Management Software	0.0	150.0	0.0	150.0
Other Projects with <$100k Spending	0.0	230.0	-130.0	100.0
Subtotal	**0.0**	**630.0**	**-380.0**	**250.0**
Deferred Costs – Projects $100,000 to $1 million				
Renewable Diesel Pilot Project	25.0	200.0	0.0	225.0
Skagway Shoreside Power	100.0	50.0	0.0	150.0
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
Breaker Condition Assessment	0.0	100.0	-100.0	0.0
Substation and Distribution Load Planning Study	0.0	300.0	0.0	300.0
WRGS Thermal Assessment & Permitting	413.0	0.0	-413.0	0.0
GRA 2023-2024 (Hearing Reserve Acct)	250.0	0.0	0.0	250.0
Other Projects with <$100k Spending	25.0	75.0	10.0	110.0
Subtotal	**813.0**	**1,175.0**	**-953.0**	**1,035.0**
Total	**106,439.4**	**107,396.0**	**-58,905.1**	**154,930.3**

YEC 2025-27 GRA **Table 5.2B**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2024 Approved **MAY 2025**
($000S)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Capital Projects Contributions – Major projects > $1 million				
Energy Storage System Contributions	-10,874.0	-5,626.0	0.0	-16,500.0
IPP Connections Customer Contributions	-6,222.9	-307.8	1,035.6	-5,495.1
Lewes River Boat Lock Insurance Proceeds	-4,407.5	-113.0	0.0	-4,520.5
Subtotal	-21,504.4	-6,046.8	1,035.6	-26,515.6
Capital Projects Contributions – Projects $100,000 to $1 million				
Customer Extensions Customer Contributions	0.0	-400.0	400.0	0.0
Subtotal	0.0	-400.0	400.0	0.0
Deferred Costs Contributions – Major projects > $1 million				
Atlin Hydro SIS and EPA Contributions	-355.8	0.0	0.0	-355.8
Subtotal	-355.8	0.0	0.0	-355.8
Total	**-21,860.2**	**-6,446.8**	**1,435.6**	**-26,871.4**
Total Major Projects	80,324.0	89,663.2	-50,234.7	119,752.6
Capital Projects – Projects $100,000 to $1 million				
Total Generation	216.7	1,560.0	-1,075.0	701.7
Total Transmission	405.0	1,179.0	-1,484.0	100.0
Total Distribution	0.0	1,005.0	-755.0	250.0
Total General Plant & Equipment	140.0	2,872.0	-2,612.0	400.0
Right of Use Assets	0.0	0.0	0.0	0.0
Total Overhaul	0.0	400.0	-400.0	0.0
Total Intangible Assets	0.0	630.0	-380.0	250.0
Total Capital Projects	81,085.7	97,309.2	-56,940.7	121,454.2
Total Deferred Costs	26,166.7	11,261.8	-2,917.4	34,511.1
Total Contributions				
Total Capital Contributions	-21,504.4	-6,446.8	1,435.6	-26,515.6
Total Deferred Cost Contributions	-355.8	0.0	0.0	-355.8
RFID				
RFID	0.0	681.7	-681.7	0.0
Total Net RFID	**0.0**	**681.7**	**-681.7**	**0.0**

YEC 2025-27 GRA **Table 5.3**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2023 Actuals **MAY 2025**
($000S)

Category of capital project	2023 Opening WIP	2023 Capital Expen	2023 Completed Projects	2023 Closing WIP
Capital Projects – Major projects > $2 million				
Generation				
Wareham Dam Spillway Project - Tunnel	0.0	170.6	0.0	170.6
Thermal Replacement (16.5 MW)	6,297.3	31,122.8	-122.4	37,297.7
Battery Energy Storage System	10,000.7	5,781.8	0.0	15,782.5
MH0 rockslide Stabilization and Remediation	0.0	2,122.8	0.0	2,122.8
Mayo Mobile Diesel Genset	0.0	5,289.7	-5,289.7	0.0
MH0 Surge Chamber Replacement	324.5	75.3	0.0	399.8
Transmission				
Whitehorse Interconnection	8,403.9	2,368.7	-10,772.5	0.0
Transmission Line Refurbishment L178	0.0	650.7	0.0	650.7
P&C: S250 Callison Protection, Control and SCADA Upgrade	388.1	1,773.6	-2,158.1	3.6
Distribution				
Dawson Voltage Conversion	71.8	411.1	0.0	482.8
IPP Connections	3,705.3	2,816.3	-538.4	5,983.3
General Plant				
Whitehorse Stoplog Crane Replacement	322.8	2,145.2	0.0	2,467.9
Overhaul				
AH1 10 Year Overhaul	31.0	2,306.9	-2,337.9	0.0
Intangible Assets – Major projects > $2 million				
PAMMS Asset Management Framework	4,455.2	1,004.3	-5,459.5	0.0
Subtotal	**34,000.5**	**58,039.7**	**-26,678.5**	**65,361.7**
Deferred Costs – Major projects > $2 million				
Licensing				
Mayo Lake Enhanced Storage	4,541.4	104.1	0.0	4,645.5
Aishihik 25-Year Water Use License Renewal	5,734.9	851.2	0.0	6,586.2
WRGS Long-term Water Use License Renewal	2,120.0	4,163.3	0.0	6,283.3
MGS 5-year Water Use License Renewal	94.2	1,391.2	0.0	1,485.5
Regulatory				
Integrated Resource Plan	0.0	288.5	0.0	288.5
Subtotal	**12,490.6**	**6,798.3**	**0.0**	**19,288.9**
Capital Projects – Projects $400,000 to $2 million				
Generation				
MH0 Road & Road Slope Stability	934.4	828.1	-1,762.5	0.0
Wareham Spillway Concrete Repair	0.0	201.2	0.0	201.2
Schwatka Lake Safety/Debris Boom	581.2	534.6	0.0	1,115.9
Lewes River Boat Lock	64.3	850.5	-20.4	894.4
Other Projects with <$400k Spending	310.6	-248.1	207.5	270.1
Subtotal	**1,890.5**	**2,166.4**	**-1,575.4**	**2,481.5**
Transmission				
L177 Re Route	304.7	219.7	-524.4	0.0
Protection and Control - S170	0.0	0.3	0.0	0.3
T9 Transformer Critical Spare	*0.0*	*43.6*	*0.0*	43.6
Other Projects with <$400k Spending	14.4	226.3	-211.7	29.1
Subtotal	**319.1**	**490.0**	**-736.1**	**73.0**

YEC 2025-27 GRA **Table 5.3**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2023 Actuals **MAY 2025**
($000S)

	2023			
Category of capital project	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Distribution				
Customer Extensions	1,127.1	568.8	-152.6	1,543.3
Synchronous Condenser Overhaul	416.3	575.5	-991.8	0.0
Dawson Distribution 3 Phase Loop	0.0	500.2	-500.2	0.0
South Fox Lake PT Upgrades	*0.0*	*41.0*	*0.0*	41.0
Mendenhall PT	0.0	37.5	0.0	37.5
Distribution Upgrades	*0.0*	*210.9*	*-210.9*	0.0
Subtotal	**1,543.3**	**1,934.1**	**-1,855.5**	**1,621.9**
General Plant				
Vehicle Purchases	0.0	612.6	-612.6	0.0
New Mobile Office Unit - IT	185.2	553.5	-738.7	0.0
Fish Ladder TWG Recommendations Implementation	0.0	16.4	0.0	16.4
SCADA Upgrade Program	0.0	18.8	-18.8	0.0
Other Projects with <$400k Spending	154.3	1,330.2	-1,472.3	12.3
Subtotal	**339.6**	**2,531.4**	**-2,842.3**	**28.7**
Overhaul				
Other Projects with <$400k Spending	0.0	690.5	-690.5	0.0
Subtotal	**0.0**	**690.5**	**-690.5**	**0.0**
Intangible Assets – Projects $400,000 to $2 million				
Tailrace Gate Certifications	0.0	266.2	0.0	266.2
ERP Replacement	99.8	18.4	0.0	118.2
Other Projects with <$400k Spending	6.1	143.0	-86.9	62.2
Subtotal	**105.9**	**427.7**	**-86.9**	**446.7**
Deferred Costs – Projects $400,000 to $2 million				
AGS 5-Year Fisheries Act Authorization	575.4	0.0	0.0	575.4
DSM Program 2022-2030	0.0	1,289.2	-1,289.2	0.0
Atlin Hydro SIS and EPA	1,474.2	134.5	0.0	1,608.7
GRA 2023-2024 (Hearing Reserve Acct)	0.0	337.4	0.0	337.4
Other Projects with <$400k Spending	663.5	1,434.7	-994.5	1,103.7
Subtotal	**2,713.0**	**3,195.8**	**-2,283.7**	**3,625.1**
Total	**53,402.5**	**76,273.9**	**-36,749.0**	**92,927.5**
Capital Projects Contributions – Major projects > $2 million				
Battery Energy Storage System Contributions	-7,026.1	-3,847.9	0.0	-10,874.0
IPP Connections Customer Contributions	-4,900.9	-1,822.4	500.4	-6,222.9
Lewes River Boat Lock Contributions	0.0	-4,520.5	4,520.5	0.0
Subtotal	-11,927.0	-10,190.8	5,020.9	-17,096.9
Capital Projects Contributions – Projects $400,000 to $2 million				
Customer Extensions Customer Contributions	-860.7	-466.9	88.0	-1,239.6
L177 Re Route Contributions	0.0	-524.4	524.4	0.0
Subtotal	-860.7	-991.3	612.4	-1,239.6
Deferred Costs Contributions				
DSM Program Development Contributions	0.0	-385.6	385.6	0.0
Atlin Hydro SIS and EPA Contributions	-288.5	-67.2	0.0	-355.8
Subtotal	-288.5	-452.9	385.6	-355.8
Total	**-13,076.3**	**-11,635.0**	**6,018.9**	**-18,692.3**

YEC 2025-27 GRA **Table 5.3**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2023 Actuals **MAY 2025**
($000S)

Category of capital project	2023 Opening WIP	2023 Capital Expen	2023 Completed Projects	2023 Closing WIP
Total Major Projects > $2 million	34,000.5	58,039.7	-26,678.5	65,361.7
Capital Projects – Projects $400,000 to $2 million				
Total Generation	1,890.5	2,166.4	-1,575.4	2,481.5
Total Transmission	319.1	490.0	-736.1	73.0
Total Distribution	1,543.3	1,934.1	-1,855.5	1,621.9
Total General Plant & Equipment	339.6	2,531.4	-2,842.3	28.7
Overhaul	0.0	690.5	-690.5	0.0
Intangible Assets	105.9	427.7	-86.9	446.7
Total Capital Projects	38,198.9	66,279.8	-34,465.2	70,013.5
Total Deferred Costs	15,203.6	9,994.2	-2,283.7	22,914.0
Total Contributions				
Total Capital Contributions	-12,787.7	-11,182.1	5,633.3	-18,336.5
Total Deferred Cost Contributions	-288.5	-452.9	385.6	-355.8
RFID				
RFID	345.9	554.8	-900.7	0.0
Total Net RFID	**345.9**	**554.8**	**-900.7**	**0.0**
Reserve for Site Restoration				
Reserve for Site Restoration Bucket	40.1	605.1	-645.2	0.0
Total Net RFSR	**40.1**	**605.1**	**-645.2**	**0.0**

YEC 2025-27 GRA **Table 5.4**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2024 Preliminary Actuals **MAY 2025**
($000S)

	2024			
Category of capital project	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Capital Projects – Major projects > $2 million				
Generation				
Wareham Dam Spillway Project - Tunnel	170.6	3,541.4	0.0	3,712.0
Thermal Replacement (16.5 MW)	37,297.7	14,406.0	0.0	51,703.7
Battery Energy Storage System	15,782.5	4,873.9	0.0	20,656.5
MH0 rockslide Stabilization and Remediation	2,122.8	1,065.1	0.0	3,187.9
Mayo Mobile Diesel Genset	0.0	1,226.3	-1,226.3	0.0
MH0 Surge Chamber Replacement	399.8	811.7	0.0	1,211.5
WH3 Headgate Replacement		85.5	0.0	85.5
WH4 Trash Rake		138.2	0.0	138.2
Whitehorse Power Expansion		200.2	0.0	200.2
Transmission				
Whitehorse Interconnection	0.0	86.5	-86.5	0.0
Transmission Line Refurbishment L178	650.7	281.5	0.0	932.1
P&C: S250 Callison Protection, Control and SCADA Upgrade	3.6	216.7	0.0	220.3
Distribution				
Dawson Voltage Conversion	482.8	4,299.9	0.0	4,782.7
IPP Connections	5,983.3	-78.0	-5,905.3	0.0
General Plant				
Whitehorse Stoplog Crane Replacement	2,467.9	855.4	-3,323.3	0.0
Overhaul				
AH3 Overhaul		2,286.8	-2,286.8	0.0
Subtotal	**65,361.7**	**34,297.0**	**-12,828.2**	**86,830.5**
Deferred Costs – Major projects > $2 million				
Licensing				
* Mayo Lake Enhanced Storage	4,645.5	-2,378.3	-2,267.2	0.0
Aishihik 25-Year Water Use License Renewal	6,586.2	178.6	0.0	6,764.8
WRGS Long-term Water Use License Renewal	6,283.3	2,551.6	0.0	8,834.9
MGS 5-year Water Use License Renewal	1,485.5	4,169.4	0.0	5,654.8
Regulatory				
Integrated Resource Plan	288.5	293.1	0.0	581.6
Subtotal	**19,288.9**	**4,814.4**	**-2,267.2**	**21,836.1**
Capital Projects – Projects $400,000 to $2 million				
Generation				
MH0 Road & Road Slope Stability	0.0	44.4	-44.4	0.0
Whitehorse Spillway Stoplog Refurbishment		453.0	0.0	453.0
Wareham Spillway Concrete Repair	201.2	735.5	-936.7	0.0
Schwatka Lake Safety/Debris Boom	1,115.9	104.4	-1,220.2	0.0
Lewes River Boat Lock	894.4	545.7	0.0	1,440.1
WHS East Gate Refurbishment		7.8	0.0	7.8
Other Projects with <$400k Spending	270.1	1,185.1	-1,088.9	366.2
Subtotal	**2,481.5**	**3,075.8**	**-3,290.2**	**2,267.1**
Transmission				
Load Bank and Transformers		1,722.8	-1,722.8	0.0
Protection, Control and SCADA Upgrade - WH4		*13.0*	*0.0*	13.0
Transmission Line Test and Treat Program		163.0	0.0	163.0
Protection and Control - S170	0.3	18.4	0.0	18.6
Other Projects with <$400k Spending	72.7	870.5	-380.9	562.4
Subtotal	**73.0**	**2,787.6**	**-2,103.7**	**756.9**

YEC 2025-27 GRA **Table 5.4**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2024 Preliminary Actuals **MAY 2025**
($000S)

	2024			
Category of capital project	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Distribution				
Customer Extensions	1,543.3	1,111.9	-2,655.2	0.0
South Fox Lake PT Upgrades	41.0	*416.8*	*0.0*	457.8
Distribution Upgrades	0.0	166.7	-166.7	0.0
Mendenhall PT	37.5	*362.4*	*0.0*	399.9
Other Projects with <$400k Spending	0.0	27.2	-27.2	0.0
Subtotal	**1,621.9**	**2,084.9**	**-2,849.0**	**857.8**
General Plant				
Vehicle Purchases	0.0	890.2	-890.2	0.0
Crane Refurbishment Program		115.1	-115.1	0.0
Fish Ladder TWG Recommendations Implementation	16.4	*251.6*	*0.0*	268.1
HQ Datacenter Server Replacement		492.2	-492.2	0.0
Mayo Digger		453.5	-453.5	0.0
SCADA Upgrade Program	0.0	18.3	-18.3	0.0
Computer Replacements	0.0	138.3	-138.3	0.0
Other Projects with <$400k Spending	12.3	1,172.7	-1,091.8	93.2
Subtotal	**28.7**	**3,532.0**	**-3,199.4**	**361.3**
Overhaul				
WG0 Major Plant Overhaul		60.2	0.0	60.2
WG3 Overhaul		453.2	-453.2	0.0
MBH2 Overhaul		96.9	0.0	96.9
Subtotal	**0.0**	**610.3**	**-453.2**	**157.1**
Intangible Assets – Projects $400,000 to $2 million				
Tailrace Gate Certifications	266.2	286.1	-552.4	0.0
ERP Replacement	118.2	0.0	0.0	118.2
Gate Certification Program		177.8	0.0	177.8
Other Projects with <$400k Spending	62.2	746.1	-340.4	467.9
Subtotal	**446.7**	**1,210.0**	**-892.7**	**763.9**
Deferred Costs – Projects $400,000 to $2 million				
AGS 5-Year Fisheries Act Authorization	575.4	138.9	0.0	714.2
DSM Program 2022-2030	0.0	1,101.6	-1,101.6	0.0
Atlin Hydro SIS and EPA	1,608.7	73.4	0.0	1,682.1
GRA 2023-2024 (Hearing Reserve Acct)	337.4	524.1	0.0	861.6
GRA 2025-27 (Hearing Reserve Acct)		*7.4*	*0.0*	7.4
Other Projects with <$400k Spending	1,103.7	1,361.0	-952.1	1,512.6
Subtotal	**3,625.1**	**3,206.4**	**-2,053.6**	**4,777.8**
Total	**92,927.5**	**55,618.3**	**-29,937.3**	**118,608.5**
Capital Projects Contributions – Major projects > $2 million				
Battery Energy Storage System Contributions	-10,874.0	-1,889.2	0.0	-12,763.2
IPP Connections Customer Contributions	-6,222.9	66.5	6,156.4	0.0
Subtotal	-17,096.9	-1,822.7	6,156.4	-12,763.2
Capital Projects Contributions – Projects $400,000 to $2 million				
Customer Extensions Customer Contributions	-1,239.6	-1,019.3	2,258.9	0.0
Alexco (Hecla) Keno Hill Minesite - Substation Upgrade Contributions		-169.7	0.0	-169.7
Subtotal		-1,189.0	2,258.9	-169.7

YEC 2025-27 GRA | **Table 5.4**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2024 Preliminary Actuals | **MAY 2025**
($000S)

Category of capital project	2024 Opening WIP	2024 Capital Expen	2024 Completed Projects	2024 Closing WIP
Deferred Costs Contributions				
DSM Program Development Contributions	0.0	-457.9	457.9	0.0
Atlin Hydro SIS and EPA Contributions	-355.8	0.0	0.0	-355.8
Grid Modernization Study Contributions		-62.5	0.0	-62.5
Subtotal	-355.8	-520.4	457.9	-418.3
Total	**-18,692.3**	**-3,532.1**	**8,873.2**	**-13,351.2**
Total Major Projects > $2 million	65,361.7	34,297.0	-12,828.2	86,830.5
Capital Projects – Projects $400,000 to $2 million				
Total Generation	2,481.5	3,075.8	-3,290.2	2,267.1
Total Transmission	73.0	2,787.6	-2,103.7	756.9
Total Distribution	1,621.9	2,084.9	-2,849.0	857.8
Total General Plant & Equipment	28.7	3,532.0	-3,199.4	361.3
Overhaul	0.0	610.3	-453.2	157.1
Total Intangible Assets	446.7	1,210.0	-892.7	763.9
Total Capital Projects	70,013.5	47,597.6	-25,616.5	91,994.6
Total Deferred Costs	22,914.0	8,020.8	-4,320.8	26,613.9
Total Contributions				
Total Capital Contributions	-17,096.9	-3,011.7	8,415.3	-12,932.9
Total Deferred Cost Contributions	-355.8	-520.4	457.9	-418.3
RFID				
RFID	0.0	9,581.0	0.0	9,581.0
RFID Contributions		-7,161.4	0.0	-7,161.4
Total Net RFID	**0.0**	**2,419.6**	**0.0**	**2,419.6**
Reserve for Site Restoration				
Reserve for Site Restoration Bucket	0.0	0.0	0.0	0.0
Total Net RFSR	**0.0**	**0.0**	**0.0**	**0.0**

*) - net of transfer to Mayo Lake Relicensing project.

YEC 2025-27 GRA — **Table 5.5**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2025 Forecast — **MAY 2025**
($000S)

Category of capital project	2025 Opening WIP	2025 Capital Expen	2025 Completed Projects	2025 Closing WIP
Capital Projects – Major projects > $2 million				
Generation				
Wareham Dam Spillway Project - Tunnel	3,712.0	5,221.4	0.0	8,933.3
Wareham Dam Spillway Project - Full Replacement		4,114.4	0.0	4,114.4
Thermal Replacement (16.5 MW)	51,703.7	10,516.0	-62,219.7	0.0
Battery Energy Storage System	20,656.5	14,301.4	0.0	34,957.9
MH0 rockslide Stabilization and Remediation	3,187.9	42,242.1	0.0	45,430.0
MH0 Surge Chamber Replacement	1,211.5	2,624.0	0.0	3,835.5
WH3 Headgate Replacement	85.5	2,450.0	-2,535.5	0.0
Dam Safety Review Mitigations		300.0	-300.0	0.0
WH4 Trash Rake	138.2	100.0	0.0	238.2
Whitehorse Power Expansion	200.2	1,500.0	0.0	1,700.2
Transmission				
Transmission Line Refurbishment L178	932.1	2,400.0	0.0	3,332.1
P&C: S250 Callison Protection, Control and SCADA Upgrade	220.3	0.0	-220.3	0.0
Spare Power Transformer Program		75.0	0.0	75.0
Transmission line hazard tree reduction and ROW widening program		949.9	-949.9	0.0
Distribution				
Dawson Voltage Conversion	4,782.7	1,010.0	-5,792.7	0.0
General Plant				
Office Building		*500.0*	*0.0*	500.0
Subtotal	**86,830.5**	**88,304.2**	**-72,018.1**	**103,116.6**
Deferred Costs – Major projects > $2 million				
Licensing				
Aishihik 25-Year Water Use License Renewal	6,764.8	650.0	0.0	7,414.8
WRGS Long-term Water Use License Renewal	8,834.9	1,773.0	-10,607.9	0.0
MGS 5-year Water Use License Renewal	5,654.8	1,640.0	-7,294.8	0.0
Regulatory				
Integrated Resource Plan	581.6	750.0	0.0	1,331.6
Subtotal	**21,836.1**	**4,813.0**	**-17,902.7**	**8,746.3**
Capital Projects – Projects $400,000 to $2 million				
Generation				
Whitehorse Spillway Stoplog Refurbishment	453.0	1,499.0	-1,952.0	0.0
Wareham Spillway Concrete Repair	0.0	0.0	0.0	0.0
Lewes River Boat Lock	1,440.1	200.0	-1,640.1	0.0
WHS East Gate Refurbishment	7.8	*200.0*	*0.0*	207.8
Aishihik Canyon Control Structure Instrumentation, Control and Communications		*150.0*	*0.0*	150.0
Critical Spare Parts - Hydro Generation Units		*650.0*	*0.0*	650.0
Other Projects with <$400k Spending	366.2	950.0	-1,157.4	158.8
Subtotal	**2,267.1**	**3,649.0**	**-4,749.5**	**1,166.6**
Transmission				
Protection, Control and SCADA Upgrade - WH4	13.0	*450.0*	*0.0*	463.0
Transmission Line Test and Treat Program	163.0	300.0	-463.0	0.0
T250-30 Silver King Transformer Replacement		*80.0*	*0.0*	80.0
Transmission Structure Replacements		*200.0*	*0.0*	200.0
Protection and Control - S170	18.6	434.0	0.0	452.6
Other Projects with <$400k Spending	562.4	745.0	-772.2	535.2
Subtotal	**756.9**	**2,209.0**	**-1,235.2**	**1,730.7**

YEC 2025-27 GRA **Table 5.5**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2025 Forecast **MAY 2025**
($000S)

	2025			
Category of capital project	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Distribution				
Customer Extensions	0.0	600.0	-600.0	0.0
Distribution Pole and Transformer Replacement Program		*350.0*	*-350.0*	0.0
Grid Modernization Program		*50.0*	*0.0*	50.0
South Fox Lake PT Upgrades	457.8	0.0	-457.8	0.0
EV Infrastructure Transition		*35.0*	*0.0*	35.0
Distribution Upgrades	0.0	150.0	-150.0	0.0
Mendenhall PT	399.9	*0.0*	*-399.9*	0.0
Other Projects with <$400k Spending	0.0	25.0	-25.0	0.0
Subtotal	**857.8**	**1,210.0**	**-1,982.8**	**85.0**
General Plant				
Vehicle Purchases	0.0	675.0	-675.0	0.0
Crane Refurbishment Program	0.0	400.0	-400.0	0.0
Building Condition Report Refurbishments		400.0	-400.0	0.0
Fish Ladder TWG Recommendations Implementation	268.1	275.0	-543.1	0.0
Central Storeroom for Generation Parts		200.0	0.0	200.0
SCADA Upgrade Program	0.0	10.0	-10.0	0.0
Computer Replacements	0.0	160.0	-160.0	0.0
Other Projects with <$400k Spending	93.2	1,015.0	-828.7	279.6
Subtotal	**361.3**	**3,135.0**	**-3,016.7**	**479.6**
Overhaul				
MBH2 Overhaul	96.9	1,500.0	-1,596.9	0.0
MBH1 Overhaul		75.0	0.0	75.0
WG1 30,000 Hour Overhaul		1,520.0	-1,520.0	0.0
DD4 Overhaul		975.0	-975.0	0.0
WG0 Major Plant Overhaul	60.2	500.0	-560.2	0.0
Subtotal	**157.1**	**4,570.0**	**-4,652.1**	**75.0**
Intangible Assets – Projects $400,000 to $2 million				
ERP Replacement	118.2	500.0	0.0	618.2
Gate Certification Program	177.8	450.0	-627.8	0.0
Other Projects with <$400k Spending	467.9	1,035.0	-1,402.9	100.0
Subtotal	**763.9**	**1,985.0**	**-2,030.7**	**718.2**
Deferred Costs – Projects $400,000 to $2 million				
AGS 5-Year Fisheries Act Authorization	714.2	0.0	-714.2	0.0
DSM Program 2022-2030	0.0	747.0	-747.0	0.0
Atlin Hydro SIS and EPA	1,682.1	100.0	0.0	1,782.1
GRA 2023-2024 (Hearing Reserve Acct)	861.6	405.0	0.0	1,266.6
GRA 2025-27 (Hearing Reserve Acct)	7.4	*400.0*	*0.0*	407.4
Other Projects with <$400k Spending	1,512.6	820.0	-2,332.6	0.0
Subtotal	**4,777.8**	**2,472.0**	**-3,793.8**	**3,456.0**
Total	**118,608.5**	**112,347.2**	**-111,381.7**	**119,574.0**

YEC 2025-27 GRA | **Table 5.5**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2025 Forecast | **MAY 2025**
($000S)

	2025			
Category of capital project	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Capital Projects Contributions – Major projects > $2 million				
Battery Energy Storage System Contributions	-12,763.2	-3,736.8	0.0	-16,500.0
Subtotal	-12,763.2	-3,736.8	0.0	-16,500.0
Capital Projects Contributions – Projects $400,000 to $2 million				
Customer Extensions Customer Contributions	0.0	-400.0	400.0	0.0
Alexco (Hecla) Keno Hill Minesite - Substation Upgrade Contributions	-169.7	0.0	0.0	-169.7
Subtotal	-169.7	-400.0	400.0	-169.7
Deferred Costs Contributions				
Atlin Hydro SIS and EPA Contributions	-355.8	0.0	0.0	-355.8
Grid Modernization Study Contributions	-62.5	0.0	62.5	0.0
Subtotal	-418.3	0.0	62.5	-355.8
Total	**-13,351.2**	**-4,136.8**	**462.5**	**-17,025.5**
Total Major Projects > $2 million	86,830.5	88,304.2	-72,018.1	103,116.6
Capital Projects – Projects $400,000 to $2 million				
Total Generation	2,267.1	3,649.0	-4,749.5	1,166.6
Total Transmission	756.9	2,209.0	-1,235.2	1,730.7
Total Distribution	857.8	1,210.0	-1,982.8	85.0
Total General Plant & Equipment	361.3	3,135.0	-3,016.7	479.6
Overhaul	157.1	4,570.0	-4,652.1	75.0
Total Intangible Assets	763.9	1,985.0	-2,030.7	718.2
Total Capital Projects	91,994.6	105,062.2	-89,685.1	107,371.7
Total Deferred Costs	26,613.9	7,285.0	-21,696.5	12,202.4
Total Contributions				
Total Capital Contributions	-12,932.9	-4,136.8	400.0	-16,669.7
Total Deferred Cost Contributions	-418.3	0.0	62.5	-355.8
RFID				
RFID	9,581.0	554.0	-10,135.0	0.0
RFID Contributions	-7,161.4	0.0	7,161.4	0.0
Total Net RFID	**2,419.6**	**554.0**	**-2,973.6**	**0.0**
Reserve for Site Restoration				
Reserve for Site Restoration Bucket	0.0	0.0	0.0	0.0
Total Net RFSR	**0.0**	**0.0**	**0.0**	**0.0**

YEC 2025-27 GRA **Table 5.6**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2026 Forecast **MAY 2025**
($000S)

Category of capital project	2026			
	Opening WIP	Capital Expen	Completed Projects	Closing WIP
Capital Projects – Major projects > $2 million				
Generation				
Wareham Dam Spillway Project - Tunnel	8,933.3	35,914.8	0.0	44,848.1
Wareham Dam Spillway Project - Full Replacement	4,114.4	503.1	0.0	4,617.4
Battery Energy Storage System	34,957.9	0.0	-34,957.9	0.0
MH0 rockslide Stabilization and Remediation	45,430.0	33,214.6	-78,644.6	0.0
MH0 Surge Chamber Replacement	3,835.5	23,995.3	-27,830.7	0.0
Dam Safety Review Mitigations	0.0	1,200.0	-1,200.0	0.0
WH4 Trash Rake	238.2	5.0	0.0	243.2
WH0 P125 Trash Rake		195.0	0.0	195.0
WH1 Uprate		250.0	0.0	250.0
Whitehorse Power Expansion	1,700.2	2,500.0	0.0	4,200.2
Mayo MH0 Plant Renewal or Replacement		1,000.0	0.0	1,000.0
Transmission				
Transmission Line Refurbishment L178	3,332.1	1,584.0	0.0	4,916.1
Spare Power Transformer Program	75.0	275.0	0.0	350.0
Transmission line hazard tree reduction and ROW widening program	0.0	949.9	-949.9	0.0
Carmacks Substation Relocate		250.0	0.0	250.0
General Plant				
PLT Shop		500.0	0.0	500.0
Office Building	500.0	1,000.0	0.0	1,500.0
Overhaul				
WH3 10 Year Overhaul		50.0	0.0	50.0
Subtotal	**103,116.6**	**103,386.6**	**-143,583.2**	**62,920.0**
Deferred Costs – Major projects > $2 million				
Licensing				
Aishihik 25-Year Water Use License Renewal	7,414.8	1,450.0	0.0	8,864.8
Regulatory				
Integrated Resource Plan	1,331.6	1,000.0	-2,331.6	0.0
Subtotal	**8,746.3**	**2,450.0**	**-2,331.6**	**8,864.8**
Capital Projects – Projects $400,000 to $2 million				
Generation				
Wareham Spillway Concrete Repair	0.0	0.0	0.0	0.0
WHS West Gate Refurbishment		200.0	0.0	200.0
WHS East Gate Refurbishment	207.8	*700.0*	*-907.8*	0.0
Aishihik Canyon Control Structure Instrumentation, Control and Commu	150.0	*500.0*	*-650.0*	0.0
MBH0 Cooling Circuit		60.0	0.0	60.0
Renewable Resource Projects		400.0	0.0	400.0
Critical Spare Parts - Hydro Generation Units	650.0	*600.0*	*-1,250.0*	0.0
Other Projects with <$400k Spending	158.8	669.0	-619.0	208.8
Subtotal	**1,166.6**	**3,129.0**	**-3,426.8**	**868.8**

YEC 2025-27 GRA — **Table 5.6**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2026 Forecast — **MAY 2025**
($000S)

	2026			
Category of capital project	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Transmission				
Protection, Control and SCADA Upgrade - WH4	463.0	870.0	-1,333.0	0.0
Protection, Control and SCADA Upgrade - S150		600.0	0.0	600.0
Transmission Line Test and Treat Program	0.0	300.0	-300.0	0.0
T250-30 Silver King Transformer Replacement	80.0	800.0	-880.0	0.0
AH0 Switchgear and Breaker Replacement		100.0	0.0	100.0
Transmission Structure Replacements	200.0	300.0	-500.0	0.0
Protection and Control - S170	452.6	0.0	0.0	452.6
Protection and Control Upgrade S249 Breaking Resistor		450.0	-450.0	0.0
T9 Transformer Critical Spare	133.2	325.0	0.0	458.2
Other Projects with <$400k Spending	402.0	900.7	-705.6	597.1
Subtotal	**1,730.7**	**4,645.7**	**-4,168.5**	**2,207.9**
Distribution				
Customer Extensions	0.0	600.0	-600.0	0.0
Distribution Pole and Transformer Replacement Program	0.0	350.0	-350.0	0.0
Grid Modernization Program	50.0	375.0	0.0	425.0
EV Infrastructure Transition	35.0	125.0	0.0	160.0
Distribution Upgrades	0.0	150.0	-150.0	0.0
Other Projects with <$400k Spending	0.0	25.0	-25.0	0.0
Subtotal	**85.0**	**1,625.0**	**-1,125.0**	**585.0**
General Plant				
Vehicle Purchases	0.0	600.0	-600.0	0.0
Crane Refurbishment Program	0.0	450.0	-450.0	0.0
Building Condition Report Refurbishments	0.0	400.0	-400.0	0.0
Central Storeroom for Generation Parts	200.0	200.0	-400.0	0.0
P126 Building Renovation		100.0	0.0	100.0
SCADA Upgrade Program	0.0	10.0	-10.0	0.0
Computer Replacements	0.0	160.0	-160.0	0.0
Other Projects with <$400k Spending	279.6	1,490.0	-1,665.0	104.6
Subtotal	**479.6**	**3,410.0**	**-3,685.0**	**204.6**
Overhaul				
WG3 30,000 Hour Overhaul		1,520.0	-1,520.0	0.0
MBH1 Overhaul	75.0	1,525.0	-1,600.0	0.0
Subtotal	**75.0**	**3,045.0**	**-3,120.0**	**0.0**
Intangible Assets – Projects $400,000 to $2 million				
Gate Certification Program	0.0	300.0	-300.0	0.0
ERP Replacement	618.2	0.0	0.0	618.2
Other Projects with <$400k Spending	100.0	515.0	-535.0	80.0
Subtotal	**718.2**	**815.0**	**-835.0**	**698.2**
Deferred Costs – Projects $400,000 to $2 million				
Atlin Hydro SIS and EPA	1,782.1	0.0	0.0	1,782.1
DSM Program 2022-2030	0.0	484.0	-484.0	0.0
GRA 2023-2024 (Hearing Reserve Acct)	1,266.6	0.0	0.0	1,266.6
GRA 2025-27 (Hearing Reserve Acct)	407.4	350.0	0.0	757.4
GRA 2028/29 (Hearing Reserve Acct)		25.0	0.0	25.0
Other Projects with <$400k Spending	0.0	350.0	0.0	350.0
Subtotal	**3,456.0**	**1,209.0**	**-484.0**	**4,181.0**
Total	**119,574.0**	**123,715.3**	**-162,759.1**	**80,530.3**

YEC 2025-27 GRA — **Table 5.6**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2026 Forecast — **MAY 2025**
($000S)

	2026			
Category of capital project	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Capital Projects Contributions – Major projects > $2 million				
Battery Energy Storage System Contributions	-16,500.0	0.0	16,500.0	0.0
Subtotal	-16,500.0	0.0	16,500.0	0.0
Capital Projects Contributions – Projects $400,000 to $2 million				
Customer Extensions Customer Contributions	0.0	-400.0	400.0	0.0
Alexco (Hecla) Keno Hill Minesite - Substation Upgrade Contributions	-169.7	0.0	0.0	-169.7
Subtotal	-169.7	-400.0	400.0	-169.7
Deferred Costs Contributions				
Atlin Hydro SIS and EPA Contributions	-355.8	0.0	0.0	-355.8
Subtotal	-355.8	0.0	0.0	-355.8
Total	**-17,025.5**	**-400.0**	**16,900.0**	**-525.5**
Total Major Projects > $2 million	103,116.6	103,386.6	-143,583.2	62,920.0
Capital Projects – Projects $400,000 to $2 million				
Total Generation	1,166.6	3,129.0	-3,426.8	868.8
Total Transmission	1,730.7	4,645.7	-4,168.5	2,207.9
Total Distribution	85.0	1,625.0	-1,125.0	585.0
Total General Plant & Equipment	479.6	3,410.0	-3,685.0	204.6
Overhaul	75.0	3,045.0	-3,120.0	0.0
Total Intangible Assets	718.2	815.0	-835.0	698.2
Total Capital Projects	107,371.7	120,056.3	-159,943.5	67,484.5
Total Deferred Costs	12,202.4	3,659.0	-2,815.6	13,045.8
Total Contributions				
Total Capital Contributions	-16,669.7	-400.0	16,900.0	-169.7
Total Deferred Cost Contributions	-355.8	0.0	0.0	-355.8
RFID				
RFID	0.0	554.0	-554.0	0.0
Total Net RFID	**0.0**	**554.0**	**-554.0**	**0.0**
Reserve for Site Restoration				
Reserve for Site Restoration Bucket	0.0	0.0	0.0	0.0
Total Net RFSR	**0.0**	**0.0**	**0.0**	**0.0**

YEC 2025-27 GRA **Table 5.7**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2027 Forecast **MAY 2025**
($000S)

Category of capital project	2027 Opening WIP	2027 Capital Expen	2027 Completed Projects	2027 Closing WIP
Capital Projects – Major projects > $2 million				
Generation				
Wareham Dam Spillway Project - Tunnel	44,848.1	29,076.0	-73,924.1	0.0
Wareham Dam Spillway Project - Full Replacement	4,617.4	6,905.2	0.0	11,522.6
Dam Safety Review Mitigations	0.0	1,100.0	-1,100.0	0.0
WH4 Trash Rake	243.2	5.0	0.0	248.2
WH0 P125 Trash Rake	195.0	5.0	0.0	200.0
WH1 Uprate	250.0	2,000.0	0.0	2,250.0
Whitehorse Power Expansion	4,200.2	50,000.0	0.0	54,200.2
Mayo MH0 Plant Renewal or Replacement	1,000.0	2,500.0	0.0	3,500.0
Transmission				
Transmission Line Refurbishment L178	4,916.1	1,584.0	-6,500.1	0.0
Spare Power Transformer Program	350.0	2,325.0	-2,675.0	0.0
Transmission line hazard tree reduction and ROW widening program	0.0	949.9	-949.9	0.0
Carmacks Substation Relocate	250.0	3,000.0	0.0	3,250.0
General Plant				
PLT Shop	500.0	5,000.0	0.0	5,500.0
Office Building	1,500.0	2,000.0	0.0	3,500.0
Overhaul				
WH3 10 Year Overhaul	50.0	2,000.0	-2,050.0	0.0
Subtotal	**62,920.0**	**108,450.1**	**-87,199.1**	**84,171.0**
Deferred Costs – Major projects > $2 million				
Licensing				
Aishihik 25-Year Water Use License Renewal	8,864.8	905.0	-9,769.8	0.0
Subtotal	**8,864.8**	**905.0**	**-9,769.8**	**0.0**
Capital Projects – Projects $400,000 to $2 million				
Generation				
MH0 Road & Road Slope Stability		150.0	0.0	150.0
WHS West Gate Refurbishment	200.0	900.0	-1,100.0	0.0
MBH0 Cooling Circuit	60.0	400.0	-460.0	0.0
Aishihik Elevator Modernization		400.0	-400.0	0.0
Renewable Resource Projects	400.0	500.0	0.0	900.0
Critical Spare Parts - Hydro Generation Units	0.0	*400.0*	*-400.0*	0.0
Other Projects with <$400k Spending	208.8	1,495.0	-1,050.0	653.8
Subtotal	**868.8**	**4,245.0**	**-3,410.0**	**1,703.8**
Transmission				
Protection, Control and SCADA Upgrade - S150	600.0	700.0	-1,300.0	0.0
Transmission Line Test and Treat Program	0.0	200.0	-200.0	0.0
AH0 Switchgear and Breaker Replacement	100.0	680.0	-780.0	0.0
Transmission Structure Replacements	0.0	250.0	-250.0	0.0
Protection and Control - S170	452.6	0.0	0.0	452.6
Protection and Control - WD0		400.0	0.0	400.0
T9 Transformer Critical Spare	458.2	1.4	0.0	459.6
Other Projects with <$400k Spending	597.1	1,091.4	-990.0	698.5
Subtotal	**2,207.9**	**3,322.8**	**-3,520.0**	**2,010.7**

YEC 2025-27 GRA **Table 5.7**
WORK IN PROGRESS CONTINUITY SCHEDULE - 2027 Forecast **MAY 2025**
($000S)

Category of capital project	**2027 Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Distribution				
Customer Extensions	0.0	600.0	-600.0	0.0
Distribution Pole and Transformer Replacement Program	0.0	*350.0*	*-350.0*	0.0
Grid Modernization Program	425.0	*275.0*	*-700.0*	0.0
EV Infrastructure Transition	160.0	500.0	0.0	660.0
Distribution Upgrades	0.0	150.0	-150.0	0.0
Other Projects with <$400k Spending	0.0	25.0	-25.0	0.0
Subtotal	**585.0**	**1,900.0**	**-1,825.0**	**660.0**
General Plant				
Vehicle Purchases	0.0	600.0	-600.0	0.0
Crane Refurbishment Program	0.0	300.0	-300.0	0.0
Building Condition Report Refurbishments	0.0	*400.0*	*-400.0*	0.0
P126 Building Renovation	100.0	500.0	0.0	600.0
SCADA Upgrade Program	0.0	510.0	-510.0	0.0
Computer Replacements	0.0	160.0	-160.0	0.0
Other Projects with <$400k Spending	104.6	1,135.0	-1,099.6	140.0
Subtotal	**204.6**	**3,605.0**	**-3,069.6**	**740.0**
Intangible Assets – Projects $400,000 to $2 million				
Gate Certification Program	0.0	300.0	-300.0	0.0
ERP Replacement	618.2	0.0	0.0	618.2
Other Projects with <$400k Spending	80.0	465.0	-295.0	250.0
Subtotal	**698.2**	**765.0**	**-595.0**	**868.2**
Deferred Costs – Projects $400,000 to $2 million				
Atlin Hydro SIS and EPA	1,782.1	0.0	0.0	1,782.1
DSM Program 2022-2030	0.0	444.0	-444.0	0.0
GRA 2023-2024 (Hearing Reserve Acct)	1,266.6	0.0	0.0	1,266.6
GRA 2025-27 (Hearing Reserve Acct)	757.4	0.0	0.0	757.4
GRA 2028/29 (Hearing Reserve Acct)	25.0	400.0	0.0	425.0
Other Projects with <$400k Spending	350.0	0.0	0.0	350.0
Subtotal	**4,181.0**	**844.0**	**-444.0**	**4,581.0**
Total	**80,530.3**	**124,036.9**	**-109,832.4**	**94,734.8**
Capital Projects Contributions – Projects $400,000 to $2 million				
Customer Extensions Customer Contributions	0.0	-400.0	400.0	0.0
Alexco (Hecla) Keno Hill Minesite - Substation Upgrade Contributions	-169.7	0.0	0.0	-169.7
Subtotal	-169.7	-400.0	400.0	-169.7
Deferred Costs Contributions				
Atlin Hydro SIS and EPA Contributions	-355.8	0.0	0.0	-355.8
Subtotal	-355.8	0.0	0.0	-355.8
Total	**-525.5**	**-400.0**	**400.0**	**-525.5**

YEC 2025-27 GRA | **Table 5.7**

WORK IN PROGRESS CONTINUITY SCHEDULE - 2027 Forecast | **MAY 2025**

($000S)

	2027			
Category of capital project	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Total Major Projects > $2 million	62,920.0	108,450.1	-87,199.1	84,171.0
Capital Projects – Projects $400,000 to $2 million				
Total Generation	868.8	4,245.0	-3,410.0	1,703.8
Total Transmission	2,207.9	3,322.8	-3,520.0	2,010.7
Total Distribution	585.0	1,900.0	-1,825.0	660.0
Total General Plant & Equipment	204.6	3,605.0	-3,069.6	740.0
Overhaul	0.0	0.0	0.0	0.0
Total Intangible Assets	698.2	765.0	-595.0	868.2
Total Capital Projects	67,484.5	122,287.9	-99,618.7	90,153.7
Total Deferred Costs	13,045.8	1,749.0	-10,213.8	4,581.0
Total Contributions				
Total Capital Contributions	-169.7	-400.0	400.0	-169.7
Total Deferred Cost Contributions	-355.8	0.0	0.0	-355.8
RFID				
RFID	0.0	554.0	-554.0	0.0
Total Net RFID	**0.0**	**554.0**	**-554.0**	**0.0**
Reserve for Site Restoration				
Reserve for Site Restoration Bucket	0.0	0.0	0.0	0.0
Total Net RFSR	**0.0**	**0.0**	**0.0**	**0.0**

YEC 2025-27 GRA
WORK IN PROGRESS CONTINUITY SCHEDULE
($000S)

Table 5.8
MAY 2025

Category of capital project	2023 Opening WIP	2023 Capital Expen	2023 Completed Projects	2023 Closing WIP	2024 Opening WIP	2024 Capital Expen	2024 Completed Projects	2024 Closing WIP
Capital Projects – Major projects > $2 million								
Generation								
Wareham Dam Spillway Project - Tunnel	0.0	170.6	0.0	170.6	170.6	3,541.4	0.0	3,712.0
Wareham Dam Spillway Project - Full Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* Thermal Replacement (16.5 MW)	6,297.3	31,122.8	-122.4	37,297.7	37,297.7	14,406.0	0.0	51,703.7
Battery Energy Storage System	10,000.7	5,781.8	0.0	15,782.5	15,782.5	4,873.9	0.0	20,656.5
MH0 rockslide Stabilization and Remediation	0.0	2,122.8	0.0	2,122.8	2,122.8	1,065.1	0.0	3,187.9
Mayo Mobile Diesel Genset	0.0	5,289.7	-5,289.7	0.0	0.0	1,226.3	-1,226.3	0.0
MH0 Surge Chamber Replacement	324.5	75.3	0.0	399.8	399.8	811.7	0.0	1,211.5
WH3 Headgate Replacement	0.0	0.0	0.0	0.0	0.0	85.5	0.0	85.5
Dam Safety Review Mitigations	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
WH4 Trash Rake	0.0	0.0	0.0	0.0	0.0	138.2	0.0	138.2
WH0 P125 Trash Rake	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WH1 Uprate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Whitehorse Power Expansion	0.0	0.0	0.0	0.0	0.0	200.2	0.0	200.2
Mayo MH0 Plant Renewal or Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission								
Whitehorse Interconnection	8,403.9	2,368.7	-10,772.5	0.0	0.0	86.5	-86.5	0.0
Transmission Line Refurbishment L178	0.0	650.7	0.0	650.7	650.7	281.5	0.0	932.1
Spare Power Transformer Program	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
Transmission line hazard tree reduction and ROW widenii	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
P&C: S250 Callison Protection, Control and SCADA Upgrac	388.1	1,773.6	-2,158.1	3.6	3.6	216.7	0.0	220.3
Carmacks Substation Relocate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distribution								
** Dawson Voltage Conversion	71.8	411.1	0.0	482.8	482.8	4,299.9	0.0	4,782.7
IPP Connections	3,705.3	2,816.3	-538.4	5,983.3	5,983.3	-78.0	-5,905.3	0.0
General Plant								
Office Building	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
Whitehorse Stoplog Crane Replacement	322.8	2,145.2	0.0	2,467.9	2,467.9	855.4	-3,323.3	0.0
PLT Shop	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overhaul								
AH1 10 Year Overhaul	31.0	2,306.9	-2,337.9	0.0	0.0	0.0	0.0	0.0
AH3 Overhaul	0.0	0.0	0.0	0.0	0.0	2,286.8	-2,286.8	0.0
WH3 10 Year Overhaul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Intangible Assets – Major projects > $2 million								
PAMMS Asset Management Framework	4,455.2	1,004.3	-5,459.5	0.0	0.0	0.0	0.0	0.0
Subtotal	**34,000.5**	**58,039.7**	**-26,678.5**	**65,361.7**	**65,361.7**	**34,297.0**	**-12,828.2**	**86,830.5**
Deferred Costs – Major projects > $2 million								
Licensing								
Mayo Lake Enhanced Storage	4,541.4	104.1	0.0	4,645.5	4,645.5	-2,378.3	-2,267.2	0.0
Aishihik 25-Year Water Use License Renewal	5,734.9	851.2	0.0	6,586.2	6,586.2	178.6	0.0	6,764.8
WRGS Long-term Water Use License Renewal	2,120.0	4,163.3	0.0	6,283.3	6,283.3	2,551.6	0.0	8,834.9
MGS 5-year Water Use License Renewal	94.2	1,391.2	0.0	1,485.5	1,485.5	4,169.4	0.0	5,654.8
Regulatory								
Integrated Resource Plan	0.0	288.5	0.0	288.5	288.5	293.1	0.0	581.6
Subtotal	**12,490.6**	**6,798.3**	**0.0**	**19,288.9**	**19,288.9**	**4,814.4**	**-2,267.2**	**21,836.1**
Capital Projects – Projects $400,000 to $2 million								
Generation								
MH0 Road & Road Slope Stability	934.4	828.1	-1,762.5	0.0	0.0	44.4	-44.4	0.0
*** Whitehorse Spillway Stoplog Refurbishment	0.0	0.0	0.0	0.0	0.0	453.0	0.0	453.0
Wareham Spillway Concrete Repair	0.0	201.2	0.0	201.2	201.2	735.5	-936.7	0.0
Schwatka Lake Safety/Debris Boom	581.2	534.6	0.0	1,115.9	1,115.9	104.4	-1,220.2	0.0
Lewes River Boat Lock	64.3	850.5	-20.4	894.4	894.4	545.7	0.0	1,440.1
WHS West Gate Refurbishment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WHS East Gate Refurbishment	*0.0*	*0.0*	*0.0*	0.0	0.0	*7.8*	*0.0*	7.8
Aishihik Canyon Control Structure Instrumentation, Contr	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
MBH0 Cooling Circuit	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Aishihik Elevator Modernization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Resource Projects	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Critical Spare Parts - Hydro Generation Units	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
Other Projects with <$400k Spending	310.6	-248.1	207.5	270.1	270.1	1,185.1	-1,088.9	366.2
Subtotal	**1,890.5**	**2,166.4**	**-1,575.4**	**2,481.5**	**2,481.5**	**3,075.8**	**-3,290.2**	**2,267.1**

YEC 2025-27 GRA — **Table 5.8**
WORK IN PROGRESS CONTINUITY SCHEDULE — **MAY 2025**
($000S)

Category of capital project	2025 Opening WIP	2025 Capital Expen	2025 Completed Projects	2025 Closing WIP	2026 Opening WIP	2026 Capital Expen	2026 Completed Projects	2026 Closing WIP	2027 Opening WIP	2027 Capital Expen	2027 Completed Projects	2027 Closing WIP
Capital Projects – Major projects > $2 million												
Generation												
Wareham Dam Spillway Project - Tunnel	3,712.0	5,221.4	0.0	8,933.3	8,933.3	35,914.8	0.0	44,848.1	44,848.1	29,076.0	-73,924.1	0.0
Wareham Dam Spillway Project - Full Replacement	0.0	4,114.4	0.0	4,114.4	4,114.4	503.1	0.0	4,617.4	4,617.4	6,905.2	0.0	11,522.6
* Thermal Replacement (16.5 MW)	51,703.7	10,516.0	-62,219.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Battery Energy Storage System	20,656.5	14,301.4	0.0	34,957.9	34,957.9	0.0	-34,957.9	0.0	0.0	0.0	0.0	0.0
MH0 rockslide Stabilization and Remediation	3,187.9	42,242.1	0.0	45,430.0	45,430.0	33,214.6	-78,644.6	0.0	0.0	0.0	0.0	0.0
Mayo Mobile Diesel Genset	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MH0 Surge Chamber Replacement	1,211.5	2,624.0	0.0	3,835.5	3,835.5	23,995.3	-27,830.7	0.0	0.0	0.0	0.0	0.0
WH3 Headgate Replacement	85.5	2,450.0	-2,535.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dam Safety Review Mitigations	0.0	*300.0*	*-300.0*	0.0	0.0	*1,200.0*	*-1,200.0*	0.0	0.0	*1,100.0*	*-1,100.0*	0.0
WH4 Trash Rake	138.2	100.0	0.0	238.2	238.2	5.0	0.0	243.2	243.2	5.0	0.0	248.2
WH0 P125 Trash Rake	0.0	0.0	0.0	0.0	0.0	195.0	0.0	195.0	195.0	5.0	0.0	200.0
WH1 Uprate	0.0	0.0	0.0	0.0	0.0	250.0	0.0	250.0	250.0	2,000.0	0.0	2,250.0
Whitehorse Power Expansion	200.2	1,500.0	0.0	1,700.2	1,700.2	2,500.0	0.0	4,200.2	4,200.2	50,000.0	0.0	54,200.2
Mayo MH0 Plant Renewal or Replacement	0.0	0.0	0.0	0.0	0.0	1,000.0	0.0	1,000.0	1,000.0	2,500.0	0.0	3,500.0
Transmission												
Whitehorse Interconnection	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission Line Refurbishment L178	932.1	2,400.0	0.0	3,332.1	3,332.1	1,584.0	0.0	4,916.1	4,916.1	1,584.0	-6,500.1	0.0
Spare Power Transformer Program	0.0	*75.0*	*0.0*	75.0	75.0	*275.0*	*0.0*	350.0	350.0	*2,325.0*	*-2,675.0*	0.0
Transmission line hazard tree reduction and ROW wic	0.0	*949.9*	*-949.9*	0.0	0.0	*949.9*	*-949.9*	0.0	0.0	*949.9*	*-949.9*	0.0
P&C: S250 Callison Protection, Control and SCADA Up	220.3	0.0	-220.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carmacks Substation Relocate	0.0	0.0	0.0	0.0	0.0	250.0	0.0	250.0	250.0	3,000.0	0.0	3,250.0
Distribution												
** Dawson Voltage Conversion	4,782.7	1,010.0	-5,792.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP Connections	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Plant												
Office Building	0.0	*500.0*	*0.0*	500.0	500.0	*1,000.0*	*0.0*	1,500.0	1,500.0	*2,000.0*	*0.0*	3,500.0
Whitehorse Stoplog Crane Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PLT Shop	0.0	0.0	0.0	0.0	0.0	500.0	0.0	500.0	500.0	5,000.0	0.0	5,500.0
Overhaul												
AH1 10 Year Overhaul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AH3 Overhaul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WH3 10 Year Overhaul	0.0	0.0	0.0	0.0	0.0	50.0	0.0	50.0	50.0	2,000.0	-2,050.0	0.0
Intangible Assets – Major projects > $2 million												
PAMMS Asset Management Framework	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	**86,830.5**	**88,304.2**	**-72,018.1**	**103,116.6**	**103,116.6**	**103,386.6**	**-143,583.2**	**62,920.0**	**62,920.0**	**108,450.1**	**-87,199.1**	**84,171.0**
Deferred Costs – Major projects > $2 million												
Licensing												
Mayo Lake Enhanced Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Aishihik 25-Year Water Use License Renewal	6,764.8	650.0	0.0	7,414.8	7,414.8	1,450.0	0.0	8,864.8	8,864.8	905.0	-9,769.8	0.0
WRGS Long-term Water Use License Renewal	8,834.9	1,773.0	-10,607.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MGS 5-year Water Use License Renewal	5,654.8	1,640.0	-7,294.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regulatory												
Integrated Resource Plan	581.6	750.0	0.0	1,331.6	1,331.6	1,000.0	-2,331.6	0.0	0.0	0.0	0.0	0.0
Subtotal	**21,836.1**	**4,813.0**	**-17,902.7**	**8,746.3**	**8,746.3**	**2,450.0**	**-2,331.6**	**8,864.8**	**8,864.8**	**905.0**	**-9,769.8**	**0.0**
Capital Projects – Projects $400,000 to $2 million												
Generation												
MH0 Road & Road Slope Stability	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0	0.0	150.0
*** Whitehorse Spillway Stoplog Refurbishment	453.0	1,499.0	-1,952.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wareham Spillway Concrete Repair	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Schwatka Lake Safety/Debris Boom	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lewes River Boat Lock	1,440.1	200.0	-1,640.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WHS West Gate Refurbishment	0.0	0.0	0.0	0.0	0.0	200.0	0.0	200.0	200.0	900.0	-1,100.0	0.0
WHS East Gate Refurbishment	7.8	*200.0*	*0.0*	207.8	207.8	*700.0*	*-907.8*	0.0	0.0	*0.0*	*0.0*	0.0
Aishihik Canyon Control Structure Instrumentation, C	0.0	*150.0*	*0.0*	150.0	150.0	*500.0*	*-650.0*	0.0	0.0	*0.0*	*0.0*	0.0
MBH0 Cooling Circuit	0.0	0.0	0.0	0.0	0.0	60.0	0.0	60.0	60.0	400.0	-460.0	0.0
Aishihik Elevator Modernization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	400.0	-400.0	0.0
Renewable Resource Projects	0.0	0.0	0.0	0.0	0.0	400.0	0.0	400.0	400.0	500.0	0.0	900.0
Critical Spare Parts - Hydro Generation Units	0.0	*650.0*	*0.0*	650.0	650.0	*600.0*	*-1,250.0*	0.0	0.0	*400.0*	*-400.0*	0.0
Other Projects with <$400k Spending	366.2	950.0	-1,157.4	158.8	158.8	669.0	-619.0	208.8	208.8	1,495.0	-1,050.0	653.8
Subtotal	**2,267.1**	**3,649.0**	**-4,749.5**	**1,166.6**	**1,166.6**	**3,129.0**	**-3,426.8**	**868.8**	**868.8**	**4,245.0**	**-3,410.0**	**1,703.8**

YEC 2025-27 GRA **Table 5.8**
WORK IN PROGRESS CONTINUITY SCHEDULE **MAY 2025**
($000S)

Category of capital project	2023 Opening WIP	2023 Capital Expen	2023 Completed Projects	2023 Closing WIP	2024 Opening WIP	2024 Capital Expen	2024 Completed Projects	2024 Closing WIP
Transmission								
Load Bank and Transformers	0.0	0.0	0.0	0.0	0.0	1,722.8	-1,722.8	0.0
Protection, Control and SCADA Upgrade - WH4	*0.0*	*0.0*	*0.0*	0.0	0.0	*13.0*	*0.0*	13.0
Protection, Control and SCADA Upgrade - S150	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission Line Test and Treat Program	0.0	0.0	0.0	0.0	0.0	163.0	0.0	163.0
T250-30 Silver King Transformer Replacement	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
AH0 Switchgear and Breaker Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission Structure Replacements	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
L177 Re Route	304.7	219.7	-524.4	0.0	0.0	0.0	0.0	0.0
Protection and Control - S170	0.0	0.3	0.0	0.3	0.3	18.4	0.0	18.6
Protection and Control Upgrade S249 Breaking Resistor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Protection and Control - WD0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T9 Transformer Critical Spare	*0.0*	*43.6*	*0.0*	43.6	43.6	*14.6*	*0.0*	58.2
Other Projects with <$400k Spending	14.4	226.3	-211.7	29.1	29.1	856.0	-380.9	504.2
Subtotal	**319.1**	**490.0**	**-736.1**	**73.0**	**73.0**	**2,787.6**	**-2,103.7**	**756.9**
Distribution								
Customer Extensions	1,127.1	568.8	-152.6	1,543.3	1,543.3	1,111.9	-2,655.2	0.0
Synchronous Condenser Overhaul	416.3	575.5	-991.8	0.0	0.0	0.0	0.0	0.0
Dawson Distribution 3 Phase Loop	0.0	500.2	-500.2	0.0	0.0	0.0	0.0	0.0
Distribution Pole and Transformer Replacement Program	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
Grid Modernization Program	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
South Fox Lake PT Upgrades	*0.0*	*41.0*	*0.0*	41.0	41.0	*416.8*	*0.0*	457.8
EV Infrastructure Transition	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
Distribution Upgrades	*0.0*	*210.9*	*-210.9*	0.0	0.0	*166.7*	*-166.7*	0.0
Mendenhall PT	*0.0*	*37.5*	*0.0*	37.5	37.5	*362.4*	*0.0*	399.9
Other Projects with <$400k Spending	0.0	0.0	0.0	0.0	0.0	27.2	-27.2	0.0
Subtotal	**1,543.3**	**1,934.1**	**-1,855.5**	**1,621.9**	**1,621.9**	**2,084.9**	**-2,849.0**	**857.8**
General Plant								
Vehicle Purchases	0.0	612.6	-612.6	0.0	0.0	890.2	-890.2	0.0
Crane Refurbishment Program	0.0	0.0	0.0	0.0	0.0	115.1	-115.1	0.0
Building Condition Report Refurbishments	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
New Mobile Office Unit - IT	185.2	553.5	-738.7	0.0	0.0	0.0	0.0	0.0
Fish Ladder TWG Recommendations Implementation	*0.0*	*16.4*	*0.0*	16.4	16.4	*251.6*	*0.0*	268.1
HQ Datacenter Server Replacement	0.0	0.0	0.0	0.0	0.0	492.2	-492.2	0.0
Central Storeroom for Generation Parts	*0.0*	*0.0*	*0.0*	0.0	0.0	*0.0*	*0.0*	0.0
P126 Building Renovation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Digger	0.0	0.0	0.0	0.0	0.0	453.5	-453.5	0.0
SCADA Upgrade Program	0.0	18.8	-18.8	0.0	0.0	18.3	-18.3	0.0
Computer Replacements	0.0	61.4	-61.4	0.0	0.0	138.3	-138.3	0.0
Other Projects with <$400k Spending	154.3	1,272.1	-1,410.9	15.5	15.5	1,293.0	-1,091.8	216.7
Subtotal	**339.6**	**2,534.7**	**-2,842.3**	**32.0**	**32.0**	**3,652.2**	**-3,199.4**	**484.8**
Overhaul								
MBH2 Overhaul	0.0	0.0	0.0	0.0	0.0	96.9	0.0	96.9
MBH1 Overhaul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WG1 30,000 Hour Overhaul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WG3 30,000 Hour Overhaul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DD4 Overhaul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WG0 Major Plant Overhaul	0.0	0.0	0.0	0.0	0.0	60.2	0.0	60.2
WG3 Overhaul	0.0	0.0	0.0	0.0	0.0	453.2	-453.2	0.0
Other Projects with <$400k Spending	0.0	690.5	-690.5	0.0	0.0	0.0	0.0	0.0
Subtotal	**0.0**	**690.5**	**-690.5**	**0.0**	**0.0**	**610.3**	**-453.2**	**157.1**
Intangible Assets – Projects $400,000 to $2 million								
Gate Certification Program	0.0	0.0	0.0	0.0	0.0	177.8	0.0	177.8
Tailrace Gate Certifications	0.0	266.2	0.0	266.2	266.2	286.1	-552.4	0.0
ERP Replacement	99.8	18.4	0.0	118.2	118.2	0.0	0.0	118.2
Other Projects with <$400k Spending	6.1	143.0	-86.9	62.2	62.2	746.1	-340.4	467.9
Subtotal	**105.9**	**427.7**	**-86.9**	**446.7**	**446.7**	**1,210.0**	**-892.7**	**763.9**

YEC 2025-27 GRA
WORK IN PROGRESS CONTINUITY SCHEDULE
($000S)

Table 5.8
MAY 2025

	2025				2026				2027			
Category of capital project	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Transmission												
Load Bank and Transformers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Protection, Control and SCADA Upgrade - WH4	13.0	450.0	0.0	463.0	463.0	870.0	-1,333.0	0.0	0.0	0.0	0.0	0.0
Protection, Control and SCADA Upgrade - S150	0.0	0.0	0.0	0.0	0.0	600.0	0.0	600.0	600.0	700.0	-1,300.0	0.0
Transmission Line Test and Treat Program	163.0	300.0	-463.0	0.0	0.0	300.0	-300.0	0.0	0.0	200.0	-200.0	0.0
T250-30 Silver King Transformer Replacement	0.0	80.0	0.0	80.0	80.0	800.0	-880.0	0.0	0.0	0.0	0.0	0.0
AH0 Switchgear and Breaker Replacement	0.0	0.0	0.0	0.0	0.0	100.0	0.0	100.0	100.0	680.0	-780.0	0.0
Transmission Structure Replacements	0.0	200.0	0.0	200.0	200.0	300.0	-500.0	0.0	0.0	250.0	-250.0	0.0
L177 Re Route	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Protection and Control - S170	18.6	434.0	0.0	452.6	452.6	0.0	0.0	452.6	452.6	0.0	0.0	452.6
Protection and Control Upgrade S249 Breaking Resist	0.0	0.0	0.0	0.0	0.0	450.0	-450.0	0.0	0.0	0.0	0.0	0.0
Protection and Control - WD0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	400.0	0.0	400.0
T9 Transformer Critical Spare	58.2	75.0	0.0	133.2	133.2	325.0	0.0	458.2	458.2	1.4	0.0	459.6
Other Projects with <$400k Spending	504.2	670.0	-772.2	402.0	402.0	900.7	-705.6	597.1	597.1	1,091.4	-990.0	698.5
Subtotal	**756.9**	**2,209.0**	**-1,235.2**	**1,730.7**	**1,730.7**	**4,645.7**	**-4,168.5**	**2,207.9**	**2,207.9**	**3,322.8**	**-3,520.0**	**2,010.7**
Distribution												
Customer Extensions	0.0	600.0	-600.0	0.0	0.0	600.0	-600.0	0.0	0.0	600.0	-600.0	0.0
Synchronous Condenser Overhaul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dawson Distribution 3 Phase Loop	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distribution Pole and Transformer Replacement Progr	0.0	350.0	-350.0	0.0	0.0	350.0	-350.0	0.0	0.0	350.0	-350.0	0.0
Grid Modernization Program	0.0	50.0	0.0	50.0	50.0	375.0	0.0	425.0	425.0	275.0	-700.0	0.0
South Fox Lake PT Upgrades	457.8	0.0	-457.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EV Infrastructure Transition	0.0	35.0	0.0	35.0	35.0	125.0	0.0	160.0	160.0	500.0	0.0	660.0
Distribution Upgrades	0.0	150.0	-150.0	0.0	0.0	150.0	-150.0	0.0	0.0	150.0	-150.0	0.0
Mendenhall PT	399.9	0.0	-399.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Projects with <$400k Spending	0.0	25.0	-25.0	0.0	0.0	25.0	-25.0	0.0	0.0	25.0	-25.0	0.0
Subtotal	**857.8**	**1,210.0**	**-1,982.8**	**85.0**	**85.0**	**1,625.0**	**-1,125.0**	**585.0**	**585.0**	**1,900.0**	**-1,825.0**	**660.0**
General Plant												
Vehicle Purchases	0.0	675.0	-675.0	0.0	0.0	600.0	-600.0	0.0	0.0	600.0	-600.0	0.0
Crane Refurbishment Program	0.0	400.0	-400.0	0.0	0.0	450.0	-450.0	0.0	0.0	300.0	-300.0	0.0
Building Condition Report Refurbishments	0.0	400.0	-400.0	0.0	0.0	400.0	-400.0	0.0	0.0	400.0	-400.0	0.0
New Mobile Office Unit - IT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fish Ladder TWG Recommendations Implementation	268.1	275.0	-543.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HQ Datacenter Server Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Central Storeroom for Generation Parts	0.0	200.0	0.0	200.0	200.0	200.0	-400.0	0.0	0.0	0.0	0.0	0.0
P126 Building Renovation	0.0	0.0	0.0	0.0	0.0	100.0	0.0	100.0	100.0	500.0	0.0	600.0
Mayo Digger	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCADA Upgrade Program	0.0	10.0	-10.0	0.0	0.0	10.0	-10.0	0.0	0.0	510.0	-510.0	0.0
Computer Replacements	0.0	160.0	-160.0	0.0	0.0	160.0	-160.0	0.0	0.0	160.0	-160.0	0.0
Other Projects with <$400k Spending	216.7	1,015.0	-952.2	279.6	279.6	1,415.0	-1,590.0	104.6	104.6	1,060.0	-1,024.6	140.0
Subtotal	**484.8**	**3,135.0**	**-3,140.2**	**479.6**	**479.6**	**3,335.0**	**-3,610.0**	**204.6**	**204.6**	**3,530.0**	**-2,994.6**	**740.0**
Overhaul												
MBH2 Overhaul	96.9	1,500.0	-1,596.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MBH1 Overhaul	0.0	75.0	0.0	75.0	75.0	1,525.0	-1,600.0	0.0	0.0	0.0	0.0	0.0
WG1 30,000 Hour Overhaul	0.0	1,520.0	-1,520.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WG3 30,000 Hour Overhaul	0.0	0.0	0.0	0.0	0.0	1,520.0	-1,520.0	0.0	0.0	0.0	0.0	0.0
DD4 Overhaul	0.0	975.0	-975.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WG0 Major Plant Overhaul	60.2	500.0	-560.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WG3 Overhaul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Projects with <$400k Spending	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	**157.1**	**4,570.0**	**-4,652.1**	**75.0**	**75.0**	**3,045.0**	**-3,120.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Intangible Assets – Projects $400,000 to $2 million												
Gate Certification Program	177.8	450.0	-627.8	0.0	0.0	300.0	-300.0	0.0	0.0	300.0	-300.0	0.0
Tailrace Gate Certifications	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ERP Replacement	118.2	500.0	0.0	618.2	618.2	0.0	0.0	618.2	618.2	0.0	0.0	618.2
Other Projects with <$400k Spending	467.9	1,035.0	-1,402.9	100.0	100.0	590.0	-610.0	80.0	80.0	540.0	-370.0	250.0
Subtotal	**763.9**	**1,985.0**	**-2,030.7**	**718.2**	**718.2**	**890.0**	**-910.0**	**698.2**	**698.2**	**840.0**	**-670.0**	**868.2**

YEC 2025-27 GRA — **Table 5.8**
WORK IN PROGRESS CONTINUITY SCHEDULE — **MAY 2025**
($000S)

	2023				2024			
Category of capital project	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Deferred Costs – Projects $400,000 to $2 million								
AGS 5-Year Fisheries Act Authorization	575.4	0.0	0.0	575.4	575.4	138.9	0.0	714.2
DSM Program 2022-2030	0.0	1,289.2	-1,289.2	0.0	0.0	1,101.6	-1,101.6	0.0
Atlin Hydro SIS and EPA	1,474.2	134.5	0.0	1,608.7	1,608.7	73.4	0.0	1,682.1
GRA 2023-2024 (Hearing Reserve Acct)	0.0	337.4	0.0	337.4	337.4	524.1	0.0	861.6
GRA 2025-27 (Hearing Reserve Acct)	*0.0*	*0.0*	*0.0*	0.0	0.0	*7.4*	*0.0*	7.4
GRA 2028/29 (Hearing Reserve Acct)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Projects with <$400k Spending	663.5	1,431.4	-994.5	1,100.4	1,100.4	1,240.7	-952.1	1,389.1
Subtotal	**2,713.0**	**3,192.6**	**-2,283.7**	**3,621.8**	**3,621.8**	**3,086.1**	**-2,053.6**	**4,654.3**
Total	**53,402.5**	**76,273.9**	**-36,749.0**	**92,927.5**	**92,927.5**	**55,618.3**	**-29,937.3**	**118,608.5**
Capital Projects Contributions – Major projects > $2 million								
Battery Energy Storage System Contributions	-7,026.1	-3,847.9	0.0	-10,874.0	-10,874.0	-1,889.2	0.0	-12,763.2
IPP Connections Customer Contributions	-4,900.9	-1,822.4	500.4	-6,222.9	-6,222.9	66.5	6,156.4	0.0
Lewes River Boat Lock Contributions	0.0	-4,520.5	4,520.5	0.0	0.0	0.0	0.0	0.0
Subtotal	-11,927.0	-10,190.8	5,020.9	-17,096.9	-17,096.9	-1,822.7	6,156.4	-12,763.2
Capital Projects Contributions – Projects $400,000 to $2 million								
Customer Extensions Customer Contributions	-860.7	-466.9	88.0	-1,239.6	-1,239.6	-1,019.3	2,258.9	0.0
L177 Re Route Contributions	0.0	-524.4	524.4	0.0	0.0	0.0	0.0	0.0
Alexco (Hecla) Keno Hill Minesite - Substation Upgrade Cc	0.0	0.0	0.0	0.0	0.0	-169.7	0.0	-169.7
Subtotal	-860.7	-991.3	612.4	-1,239.6	-1,239.6	-1,189.0	2,258.9	-169.7
Deferred Costs Contributions								
DSM Program Development Contributions	0.0	-385.6	385.6	0.0	0.0	-457.9	457.9	0.0
Atlin Hydro SIS and EPA Contributions	-288.5	-67.2	0.0	-355.8	-355.8	0.0	0.0	-355.8
Grid Modernization Study Contributions	0.0	0.0	0.0	0.0	0.0	-62.5	0.0	-62.5
Subtotal	-288.5	-452.9	385.6	-355.8	-355.8	-520.4	457.9	-418.3
Total	**-13,076.3**	**-11,635.0**	**6,018.9**	**-18,692.3**	**-18,692.3**	**-3,532.1**	**8,873.2**	**-13,351.2**
Total Major Projects > $2 million	34,000.5	58,039.7	-26,678.5	65,361.7	65,361.7	34,297.0	-12,828.2	86,830.5
Capital Projects – Projects $400,000 to $2 million								
Total Generation	1,890.5	2,166.4	-1,575.4	2,481.5	2,481.5	3,075.8	-3,290.2	2,267.1
Total Transmission	319.1	490.0	-736.1	73.0	73.0	2,787.6	-2,103.7	756.9
Total Distribution	1,543.3	1,934.1	-1,855.5	1,621.9	1,621.9	2,084.9	-2,849.0	857.8
Total General Plant & Equipment	339.6	2,534.7	-2,842.3	32.0	32.0	3,652.2	-3,199.4	484.8
Overhaul	0.0	690.5	-690.5	0.0	0.0	610.3	-453.2	157.1
Total Intangible Assets	105.9	427.7	-86.9	446.7	446.7	1,210.0	-892.7	763.9
Total Capital Projects	38,198.9	66,283.0	-34,465.2	70,016.7	70,016.7	47,717.8	-25,616.5	92,118.1
Total Deferred Costs	15,203.6	9,990.9	-2,283.7	22,910.7	22,910.7	7,900.5	-4,320.8	26,490.4
Total Contributions								
Total Capital Contributions	-12,787.7	-11,182.1	5,633.3	-18,336.5	-18,336.5	-3,011.7	8,415.3	-12,932.9
Total Deferred Cost Contributions	-288.5	-452.9	385.6	-355.8	-355.8	-520.4	457.9	-418.3
RFID								
RFID	345.9	554.8	-900.7	0.0	0.0	9,581.0	0.0	9,581.0
RFID Contributions	0.0	0.0	0.0	0.0	0.0	-7,161.4	0.0	-7,161.4
Total Net RFID	**345.9**	**554.8**	**-900.7**	**0.0**	**0.0**	**2,419.6**	**0.0**	**2,419.6**
Reserve for Site Restoration								
Reserve for Site Restoration Bucket	40.1	605.1	-645.2	0.0	0.0	0.0	0.0	0.0
Total Net RFSR	**40.1**	**605.1**	**-645.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

YEC 2025-27 GRA
WORK IN PROGRESS CONTINUITY SCHEDULE
($000S)

Table 5.8
MAY 2025

	2025				2026				2027			
Category of capital project	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**	**Opening WIP**	**Capital Expen**	**Completed Projects**	**Closing WIP**
Deferred Costs – Projects $400,000 to $2 million												
AGS 5-Year Fisheries Act Authorization	714.2	0.0	-714.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM Program 2022-2030	0.0	747.0	-747.0	0.0	0.0	484.0	-484.0	0.0	0.0	444.0	-444.0	0.0
Atlin Hydro SIS and EPA	1,682.1	100.0	0.0	1,782.1	1,782.1	0.0	0.0	1,782.1	1,782.1	0.0	0.0	1,782.1
GRA 2023-2024 (Hearing Reserve Acct)	861.6	405.0	0.0	1,266.6	1,266.6	0.0	0.0	1,266.6	1,266.6	0.0	0.0	1,266.6
GRA 2025-27 (Hearing Reserve Acct)	7.4	*400.0*	*0.0*	407.4	407.4	*350.0*	*0.0*	757.4	757.4	*0.0*	*0.0*	757.4
GRA 2028/29 (Hearing Reserve Acct)	0.0	0.0	0.0	0.0	0.0	25.0	0.0	25.0	25.0	400.0	0.0	425.0
Other Projects with <$400k Spending	1,389.1	820.0	-2,209.1	0.0	0.0	350.0	0.0	350.0	350.0	0.0	0.0	350.0
Subtotal	**4,654.3**	**2,472.0**	**-3,670.3**	**3,456.0**	**3,456.0**	**1,209.0**	**-484.0**	**4,181.0**	**4,181.0**	**844.0**	**-444.0**	**4,581.0**
Total	**118,608.5**	**112,347.2**	**-111,381.7**	**119,574.0**	**119,574.0**	**123,715.3**	**-162,759.1**	**80,530.3**	**80,530.3**	**124,036.9**	**-109,832.4**	**94,734.8**
Capital Projects Contributions – Major projects > $2 million												
Battery Energy Storage System Contributions	-12,763.2	-3,736.8	0.0	-16,500.0	-16,500.0	0.0	16,500.0	0.0	0.0	0.0	0.0	0.0
IPP Connections Customer Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lewes River Boat Lock Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	-12,763.2	-3,736.8	0.0	-16,500.0	-16,500.0	0.0	16,500.0	0.0	0.0	0.0	0.0	0.0
Capital Projects Contributions – Projects $400,000 to $2 million												
Customer Extensions Customer Contributions	0.0	-400.0	400.0	0.0	0.0	-400.0	400.0	0.0	0.0	-400.0	400.0	0.0
L177 Re Route Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Alexco (Hecla) Keno Hill Minesite - Substation Upgrad	-169.7	0.0	0.0	-169.7	-169.7	0.0	0.0	-169.7	-169.7	0.0	0.0	-169.7
Subtotal	-169.7	-400.0	400.0	-169.7	-169.7	-400.0	400.0	-169.7	-169.7	-400.0	400.0	-169.7
Deferred Costs Contributions												
DSM Program Development Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Atlin Hydro SIS and EPA Contributions	-355.8	0.0	0.0	-355.8	-355.8	0.0	0.0	-355.8	-355.8	0.0	0.0	-355.8
Grid Modernization Study Contributions	-62.5	0.0	62.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	-418.3	0.0	62.5	-355.8	-355.8	0.0	0.0	-355.8	-355.8	0.0	0.0	-355.8
Total	**-13,351.2**	**-4,136.8**	**462.5**	**-17,025.5**	**-17,025.5**	**-400.0**	**16,900.0**	**-525.5**	**-525.5**	**-400.0**	**400.0**	**-525.5**
Total Major Projects > $2 million	86,830.5	88,304.2	-72,018.1	103,116.6	103,116.6	103,386.6	-143,583.2	62,920.0	62,920.0	108,450.1	-87,199.1	84,171.0
Capital Projects – Projects $400,000 to $2 million												
Total Generation	2,267.1	3,649.0	-4,749.5	1,166.6	1,166.6	3,129.0	-3,426.8	868.8	868.8	4,245.0	-3,410.0	1,703.8
Total Transmission	756.9	2,209.0	-1,235.2	1,730.7	1,730.7	4,645.7	-4,168.5	2,207.9	2,207.9	3,322.8	-3,520.0	2,010.7
Total Distribution	857.8	1,210.0	-1,982.8	85.0	85.0	1,625.0	-1,125.0	585.0	585.0	1,900.0	-1,825.0	660.0
Total General Plant & Equipment	484.8	3,135.0	-3,140.2	479.6	479.6	3,335.0	-3,610.0	204.6	204.6	3,530.0	-2,994.6	740.0
Overhaul	157.1	4,570.0	-4,652.1	75.0	75.0	3,045.0	-3,120.0	0.0	0.0	0.0	0.0	0.0
Total Intangible Assets	763.9	1,985.0	-2,030.7	718.2	718.2	890.0	-910.0	698.2	698.2	840.0	-670.0	868.2
Total Capital Projects	92,118.1	105,062.2	-89,808.6	107,371.7	107,371.7	120,056.3	-159,943.5	67,484.5	67,484.5	122,287.9	-99,618.7	90,153.7
Total Deferred Costs	26,490.4	7,285.0	-21,573.0	12,202.4	12,202.4	3,659.0	-2,815.6	13,045.8	13,045.8	1,749.0	-10,213.8	4,581.0
Total Contributions												
Total Capital Contributions	-12,932.9	-4,136.8	400.0	-16,669.7	-16,669.7	-400.0	16,900.0	-169.7	-169.7	-400.0	400.0	-169.7
Total Deferred Cost Contributions	-418.3	0.0	62.5	-355.8	-355.8	0.0	0.0	-355.8	-355.8	0.0	0.0	-355.8
RFID												
RFID	9,581.0	554.0	-10,135.0	0.0	0.0	554.0	-554.0	0.0	0.0	554.0	-554.0	0.0
RFID Contributions	-7,161.4	0.0	7,161.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net RFID	**2,419.6**	**554.0**	**-2,973.6**	**0.0**	**0.0**	**554.0**	**-554.0**	**0.0**	**0.0**	**554.0**	**-554.0**	**0.0**
Reserve for Site Restoration												
Reserve for Site Restoration Bucket	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net RFSR	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Notes:
*) The 2023/24 GRA assumed $18.18 million to be closed and included in rate base in 2024.
**) The initial phase of the Dawson Voltage Conversion was approved in the 2023/24 GRA. Forecast costs of $1.872 million were added to rate base in 2024.
***) The 2023/24 GRA assumed $1.0 million of the Whitehorse Spillway Stoplog Refurbishment project was to be closed and included in rate base in 2024.

APPENDIX 5.1A
CAPITAL PROJECTS >$2 MILLION ADDED TO RATE BASE

APPENDIX 5.1A: CAPITAL PROJECTS >$2 MILLION ADDED TO RATE BASE

5.1A-1: THERMAL REPLACEMENT (16.5 MW)

Table 5.1A-1: Thermal Replacement (16.5 MW) Costs Added to Rate Base

Approved Opening WIP	2024 Adjustments	2025	2026	2027	Total Additions
$39,329,000	($18,176,000)	$62,220,000	$0	$0	$44,044,000

Project Description

The Thermal Replacement project involves the replacement of 12.5 MW of retiring diesel units in Whitehorse, Faro and Dawson (which was a key component of Yukon Energy's 10-Year Renewable Electricity Plan), as well as the installation of an additional 4 MW diesel expansion in Dawson, yielding an overall planned diesel installation of 16.5 MW.

More particularly, Yukon Energy previously summarized this project in its response to YUB-YEC-1-65 in the 2023/24 YEC GRA as including:

- 5 MW diesel replacement in Faro (originally planned for in-service in 2024, and included in GRA test year rate base for 2024);
- 5 MW diesel replacement in Whitehorse (not included in GRA test year rate base for 2024); and
- 6.5 MW diesel in Dawson (not included in GRA test year rate base for 2024), including:
  - One 3.25 MW unit replacing two end-of-life diesel engines at Dawson downtown plant with one new engine at the Callison substation; and
  - A second 3.25 MW diesel generator at the Callison substation to prevent prolonged outages during emergencies.

The dependable capacity from this project helps to address the existing and forecast Yukon Integrated System dependable capacity shortfall under the N-1 planning criteria, while also retaining dependable capacity as needed for retail customers in Dawson.

The diesel replacement in Faro involves the installation of two 2.5 MW US Environmental Protection Agency (EPA) Tier 4 modular diesel units (total of 5 MW) at the Faro diesel plant in 2024 – which, at the time of the 2023/24 Yukon Energy GRA proceeding, were expected to be in-service in late 2024 – to replace the 2023 retirement of Faro Diesel 1 (FD1) (5.1 MW). This new 5 MW of thermal dependable capacity added approximately $18.2 million to Yukon Energy's 2024 year-end ratebase as approved in the 2023/24 GRA.

Due to issues identified during commissioning, however, the in-service date of the two new Faro units, FD8 and FD9, was delayed, and those units were not considered in-service until early 2025. As a result, the entire Thermal Replacement project was kept in WIP at the end of 2024, rather than treating the Faro portion as completed and approved as per the 2023/24 GRA.

The table below compares the status as approved in the 2023/24 GRA and actual 2024 preliminary results and updated forecasts.

Table 5.1A-2: 2023/24 GRA Costs, 2024 Preliminary Results and Updated Forecasts

	WIP	In-Service	2024	2025 Forecast	Project Total
Approved 2023/24 GRA	$39.329M	$18.176M	$57.505 M	$3.061M	$60.566M
Preliminary 2024 Actuals	$51.740M	$0M	$51.704 M	$10.516M	$62.220M

In addition to the Faro units approved in the 2023/24 GRA, the Thermal Replacement project also includes:

- Installation of two 2.5 MW EPA Tier 4 modular units at the Whitehorse Rapids Generating Station (WRGS) (total of 5 MW) that will replace the previously retired Whitehorse Diesel 3 (WD3) (5.15 MW) – a feasibility study completed in 2021, determined that modular units were a more cost effective option than installing the diesel replacement units in the existing P126 diesel plant which requires costly upgrades.

- Installation of two 3.25 MW EPA Tier 4 modular units at the S250 Callison Substation near Dawson City (total of 6.5 MW) to replace planned retirements of Dawson Diesel units DD2 and DD5 (total 2.5 MWs) while also addressing identified concerns about anticipated load growth in Dawson and the insufficiency of currently installed thermal capacity to supply the town in the event of 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.

Project Justification and Alternatives

As explained previously in the 2023/24 GRA, in addition to assessing added thermal requirements at Dawson City as reviewed above, Yukon Energy examined the following non-rental alternatives to providing the planned thermal replacements in 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, EPA Tier 4 diesel engines were selected for all three locations to provide reduced particulate and nitrous oxide/sulfur oxide (NOx/SOx) air emissions, with resulting positive environmental benefits for the local communities. It is anticipated that the selection of Tier 4 engines will assist with the renewal of the air emissions permit for maximum applied-for diesel capacity at both WRGS and Faro. In particular, as part of the permitting of 15.5 MW of thermal generation at the Faro site, Yukon government raised concerns about 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** – Yukon Energy 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. (Wildstone) 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 as well as an optional natural gas engine option for Whitehorse. Based on the outcome of this procurement process, Yukon Energy entered into a fixed price contract with Wildstone/Finning to complete the thermal replacements at the three locations with Tier 4 rate diesel engines.

- **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 Yukon Energy 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 oxides and sulfur 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 either ~$3.0 million higher (with 5 MW permanent capacity) or ~$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).[1] Added supply chain risks were also noted for the natural gas option unless offsite system storage were to be established in the Whitehorse area.

Yukon Energy's assessment concluded that it would 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 5 MW thermal replacement currently planned for Whitehorse 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 approximately $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 about 11 years with the 5 MW permanent natural gas option with added 5 MW gas rental capability, or about 7.5 years with the only the 5 MW permanent natural gas option.

[1] 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 that the existing odorant system currently in P126 diesel plant must also be replaced with a bigger odorant system at the LNG the plant. Excluding the need for a new vaporizer and a bigger odorant system, 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 sufficient for the above referenced natural gas options.

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;
    - Geotechnical investigations; and
    - 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; and
    - Arc flash study for each site.
- Design, manufacturing, delivery, installation, testing and commissioning of two 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 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.

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

Specific scope for the Whitehorse component of the project includes the following:

- Installation of two complete diesel generator sets, Local Engine Control Panel (LECP) and auxiliary systems (radiator, stack and silencer kit), switchgear, selective catalytic reduction (SCR) system for EPA Tier 4 engines.

- Tie-in of the existing bulk fuel tank, including a new underground fuel line and transition sumps.

- Interconnection to existing electrical, instrumentation, controls, communications and SCADA infrastructure.

- Removal and relocation of the substation fence.

- Addressing deficiencies to the Whitehorse grounding.

- Stack and exhaust heights considering clearances required for existing lightning arrestors in the substation.

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

Specific scope for the Callison component of the project includes the following:

- Installation of two complete diesel generator sets, and auxiliary systems (radiator, stack and silencer kit), switchgear, selective catalytic reduction (SCR) system for EPA Tier 4 engines.

- Installation of an e-House equipped with Local Engine Control Panels (LECP), switchgear, communication and protection systems.

- Installation of two 100,000-liter fuel storage tanks, including a new underground fuel distribution line and installation of submersible fuel pumps.

- Interconnection to existing electrical, instrumentation, controls, communications and SCADA infrastructure.

- Construction and installation of a Power Plant perimeter fence surrounding the new power plant for enhanced security and compliance with safety standards.

Project Schedule and Budget

As noted earlier, Yukon Energy selected Wildstone through a competitive tender process as the Generator EPC contractor for the replacement projects at all three locations. The Wildstone team worked closely with Yukon Energy'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. Faro was commissioned in late 2024 and determined to be in-service in early 2025. Callison commissioning commenced in March 2025 and Whitehorse commissioning is currently scheduled for August 2025.

The following table shows major cost components for the complete Thermal Replacement Project providing 16.5MW.

Table 5.1A-3: Major Costs Components for the Thermal Replacement Project

Item	Forecast
EPC Contractor - Faro	$16.065M
EPC Contractor – Dawson	$22.498M
EPC Contractor – Whitehorse	$14.740M
Station Service Supply (Faro & Dawson)	$0.877M
Yukon Energy Internal Cost	$1.157M
Owner’s Engineer (BBA)	$1.169M
Feasibility and Engineering	$1.603M
Assessment and Permitting	$0.619M
Communication and Public Engagement	$0.216M
First Nation Engagement	$0.031M
Fuel (Onsite Commissioning)	$0.801M
AFUDC	$2.444M
Contingency	$0
Total	**$62.220M**
Capital Cost per MW	$3.771M
LCOC ($/kw-yr)[2]	$228.8

Conclusion

The Levelized Cost of Capacity (LCOC) over a 40-year life for the 16.5 MW diesel replacements at Faro, Dawson and Whitehorse of $228.8 per kW-yr (2025$) is comparable to the LCOC for rental diesel costs ranging between $207.6 per kW-yr and of $279.4 per kW-yr for all YEC 2025 diesel rental costs (assuming 40-years of rentals and excluding rental capital infrastructure costs) for 2%/year and 4%/year rental cost escalation scenarios, respectively.[3]

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. Regardless, the assessments show that the LCOC for the diesel replacements is comparable to diesel rental costs and will result in cost savings when compared to the diesel rental LCOC with 3%/year and 4%/year diesel rental cost escalation.

[2] LCOC is assessed assuming $62.2 million capital cost, year 1 operating cost of $18.8 per kW with escalation at 2%/yr, 40 year project life and Yukon Energy Weighted Average Cost of Capital (WACC) for new rate base of 6.390%/year per 2025-27 GRA (60% new debt financed at 4.55% and 40% equity financed at 9.15% per the current Application). The LCOC calculations assume 96% Effective Load Carrying Capacity, taking into account the Forced Outage Rate factor of 4% (the dependable capacity of 15.84 MW).

[3] LCOC is assessed assuming 2025 rental cost for all YEC diesel rentals based on total rental cost of $7 million, 40-year project life and YEC WACC for new rate base of 6.390%/year per 2025-27 GRA (60% new debt financed at 4.55% and 40% equity financed at 9.15% per the current Application). The LCOC calculations assume 85% Effective Load Carrying Capacity, taking into account the Forced Outage Rate factor of 15% (the dependable capacity of 1.53 MW for each diesel rental unit). The diesel rental cost escalation in range of 2% to 4%/yr (LCOC of $207.6 per kW-yr for 2%/year rental cost escalation, LCOC of $239.6 per kW-yr for 3%/year rental cost escalation and LCOC of $279.4 per kW-yr for 4%/year rental cost escalation).

5.1A-2: BATTERY ENERGY STORAGE SYSTEM

Table 5.1A-4: Battery Energy Storage System Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$20,656,000	$14,301,000	$0	$0	$34,957,000

Project Description

The Battery Energy Storage System (BESS) project, initiated by Yukon Energy with an approved budget of $34,957,900 (before total contributions of $16.5 million), is designed to significantly enhance the reliability and capacity of the Yukon Energy system through the establishment of a 37 MWh battery energy storage facility with a power output capability of 17.5 MW that provides 5.5 MW of additional dependable capacity.

The project is progressing through critical phases, including detailed engineering design, procurement, and construction, aiming for completion in Q4 of 2025. The BESS project's scope involves developing comprehensive engineering packages, procuring necessary materials, and executing on-site construction work. This endeavour aims to bolster the energy system’s efficiency and reliability and facilitate the seamless integration of renewable energy sources by providing substantial storage capacity and power output to meet peak demand and stabilize the grid.

The BESS project is undertaken to provide dependable capacity to the Yukon Energy system, addressing critical needs for enhanced reliability and efficiency in energy storage and distribution. It aims to support Yukon's renewable energy goals by facilitating the integration of renewable energy sources, improving grid stability, and reducing reliance on fossil fuels. The project is expected to deliver significant net present value savings to ratepayers, estimated at $9 million over a 20-year lifespan, highlighting its economic and environmental benefits.

Implementing the BESS project now is crucial due to the growing demand for renewable energy solutions and the need to improve energy system resilience amid increasing energy consumption and climate change challenges. The timely development of the BESS project allows for the immediate enhancement of grid stability and the securement of a reliable integration of renewable energy, ensuring Yukon Energy can efficiently meet current and future energy demands. Additionally, leveraging current technological advancements and funding opportunities, such as the Federal Government's Investing in Canada Infrastructure Program (ICIP), makes the project timely and economically viable.

The strategic approach to executing the BESS project is fundamentally designed to maximize grid stabilization benefits, substantially reduce emissions from fossil fuel generation, and address the critical requirement to connect Independent Power Producers (IPP) of renewable energy, such as solar and wind, into the grid. By implementing a 40 MWh battery storage system with a 20 MW power output, the project enables Yukon Energy to manage energy supply and demand fluctuations more effectively, thereby enhancing grid stability. This capability would assist with safe and efficient integration of variable renewable energy sources, which are essential for reducing reliance on fossil fuels and achieving sustainability goals. The chosen method emphasizes not only the immediate benefits of improved grid management and reduced carbon emissions but also the long-term strategic importance of facilitating a smoother transition to renewable energy sources. This approach ensures that the BESS project directly contributes to a cleaner, more resilient, and future-proof energy infrastructure, making it an integral part of Yukon's energy transition strategy.

Part 3 Application

In January 2021, Yukon Energy applied to the Minister of Justice (the "Minister") for an energy project certificate and an energy operation certificate (the "Certificates") for the proposed Battery Energy Storage System Project. The Project has been designated by OIC 2020/180 as a "regulated project" under Part 3 of the *Public Utilities Act*. The Minister referred this Application for the Certificates to the Yukon Utilities Board for a review.

The Yukon Utilities Board review highlighted the following key points:

- The Board found that a need for the BESS Project in the near term had been established.

- While the Board found that there is a public need for the BESS Project, the ratepayer savings proposed by Yukon Energy were less persuasive to the Board. This was because the BESS Project was finishing the planning phase and moving to the procurement process stage, meaning that project costs were not firm.

- Given the early stage of the project and the significant +/- range to the engineering estimates, the Board found that there were too many uncertainties for it to make a recommendation on the effect of the BESS Project on the final rates of customers. As noted throughout the report, the final costs to be included in rates would be subject to a prudency review in Yukon Energy's future GRA.

- Consistent with the Board's views provided in Sections 3.1 and 3.2 of the report, the Board found there is a need for the BESS Project. In addition, Yukon Energy's funding procured from the federal government for the BESS Project makes it more affordable for ratepayers.

- Any comment or recommendation the Board may make about the prudence of the BESS Project at that time could, in effect, prejudge what is statutorily required to be considered at GRAs. Therefore, the Board declined the opportunity to make any such comments at that time.

The original justifcation and cost-benefit assessents as reviewed in the Part 3 Application are addressed later in this business case prior to review of update adjustments.

2023/24 General Rate Application

Yukon Energy did not present a business case in the 2023/24 GRA as the project was not proposed to be added to rate base by the end of 2024. However, Yukon Energy did respond to several interogatories.

In response to YUB-YEC-1-41(b), Yukon Energy noted that the BESS project experienced significant delays, primarily due to a confluence of factors that extended beyond the initial timelines. A key reason for the postponement was the prolonged process in finalizing the terms and conditions following the contract award signing with the EPC contractor. This delay was further exacerbated by supply chain disruptions and a rapid escalation in material costs, a consequence of post-COVID inflationary pressures. These economic changes significantly impacted the cost structure of the project, leading to increased expenses for raw materials and subcontracting services. To address these unforeseen challenges, a change order was issued to extend the contract duration. This revision was necessary to accommodate the additional time needed to navigate the complex landscape of increased costs and supply chain hurdles, ensuring that the project could proceed despite the existing challenges faced by the main EPC contractor. The cumulative effect of these factors played a pivotal role in pushing the project's completion timeline beyond its original schedule.

In the response to YUB-YEC-1-44, Yukon Energy noted that the estimated completion date for the BESS project was Q3 2024. The status of work completed to date was:

- Detailed design (50% complete);
- Foundation work (75% complete); and
- Container manufacturing (40% complete).

In response to YUB-YEC-1-42, Yukon Energy noted that during the oral hearing of the Part 3 Application, Ms. Zuliani, Yukon Energy Panel member from Hatch, stated the following regarding the BESS cost estimate: "Class 4 estimate, which is where this project sits, is we've done a basic engineering phase, defined the project, and based our costs based on site specific considerations, benchmarks, and any other information, as we pointed out, based on past projects and discussions with vendors of major components."

In response to YUB-YEC-1-62, Yukon Energy noted that project expenditures to the end of September 30, 2023, and the updated project forecast at completion, were as provided in the table below.

Table 5.1A-5: BESS Project Expenditures to September 30, 2023 and Updated Forecast to Completion

Category	Costs to End Quarter ($000's)	Forecast at Completion ($000's)
EPC Contractor	$11,069	$30,427
Engineering	$754	$755
Project Management	$485	$1,019
YEC Internal	$357	$845
Owners Engineer	$429	$890
Assessment and Permitting	$204	$243
Transmission Line	$136	$160
Engagement	$138	$288
AFUDC	$406	$895
Subtotal	**$13,978**	**$35,522**
Contingency	$0	$325
Total	**$13,978**	**$35,847**

Project Update

As of Q4 2024, the total project expenses were $20.7 Million.

From the award of this BESS project, Sungrid has been unable to achieve significant contractual obligations ranging from the completion of design packages to maintaining work on schedule. One of the most significant obstacles has been Sungrid's inability to provide a design that meets the contract requirement of 20 MW at the point of interconnection. On April 5, 2024, Sungrid proposed amending the contract to adjust pricing, capacity, and schedule. The following was proposed:

- Revised substantial completion date of January 3, 2024 to December 10, 2024; and
- Amended contract value from $27,333,594.68 for 20 MW to $23,916,895.35 for 17.5 MW based on $1,366,679.73 per MW.

Engineering work in 2024 focused on further developing engineering design packages, with several packages requiring re-submittals. During Q4 2024, the project team completed reviews of the Pre-IFC Container Electrical package and relay settings calculations and approved the stamped IFC Electrical

Balance of Plant (BoP). Additional engineering efforts and work completed in Q4 2024 included the following:

- Review the IFC Container Electrical and IFC Container Mechanical and Fire Protection design, with re-submittals required;
- Review of the Cable Ampacity Report, submitted by a new third party who will be stamping/sealing the final Container Electrical package;
- Ongoing meetings between the Energy Management System (EMS) and Power Conversion System (PCS) provider to resolve open design items; and
- Completion of Power Systems Computer Aided Design system modelling.

The project Engineering team focused on reviewing the revised submissions of the Site Safety Plan, Site Quality Plan, and Site Commissioning Plan. They were also overseeing overall project management and engineering support by reviewing designs, controlling schedules, and scope, and communicating with stakeholders. The remaining engineering design packages to be submitted by the Contractor and approved are as follows:

- BESS enclosure (Container Electrical, Mechanical & Fire Protection);
- Networking/EMS; and
- Protection and Control/SCADA.

The project includes the following primary components that are installed:

- **Battery Energy Storage System**: Battery Modules (5280); Battery Racks (220); and Battery Management System (BMS).
- **Power Conversion System (PCS) (16)**: Converters; Transformers (8 plus 1 spare); and Switchgear.
- **Containerized Buildings (16)**: Non-combustible container; Fire suppression system; HVAC system; and Lighting system.
- **Electrical Balance of Plant (EBOP)**: E-house; Transformers; Switchgear; Cables; Grounding systems; and Gantry.

- **Civil Balance of Plant (CBOP)**: Foundations; Fencing; and Access roads.

Schedule

The project schedule has undergone significant revisions since its initial development. The most recent update, provided by SunGrid on December 5, 2024, shifted the final completion to August 7, 2025. It should be noted that the most recent schedule already includes multiple missed target dates. The revised dates are based on SunGrid's proposed schedule which Yukon Energy has not accepted. SunGrid is actively collaborating with Yukon Energy, the Owner's Engineer, and third-party engineers to mitigate the impact of these challenges on the project schedule. Progress towards key project milestones is presented below.

Table 5.1A-6: BESS Project Schedule

Milestone / Deliverable	Original	Revised	Actual	Status
Limited Notice to Proceed (LNTP) Agreement with Vendor*	Feb 11, 2022	-	Q1 2022	Complete
Contract Negotiation with Preferred Battery Vendor	Feb 11, 2022	-	Q3 2022	Complete
Issue PO for Battery Vendor and EPC Contractor	Feb 14, 2022	-	Q3 2022	Complete
Access road development and site grading	Apr 29, 2022	-	Q3 2022	Complete
Fall Civil Work (helical pile foundation)	Sep 30, 2022	-	Q3 2023	Complete
BESS and BoP IFC Drawings Issued	Jul 22, 2022	Q4, 2024*	-	In Progress
Delivery of BESS and long lead items	Nov 7, 2022	Q2, 2025	-	In Progress
34.5 kV line construction complete	Jan 13, 2023	Q1, 2025*	-	In Progress
Construction completed	Mar 3, 2023	Q3, 2025	-	In Progress
Integration, Site Acceptance Testing, and commissioning	Mar 15, 2023	Q4, 2025	-	In Progress
Training	Mar 28, 2023	Q4, 2025	-	Not Started
BESS In-service	Mar 29, 2023	Q4, 2025	-	Not Started

** Target date has passed*

The significant revisions to the project schedule stem from several key factors:

- **Container design non-compliance:** Addressing these issues is essential for the timely progression of various project activities. Non-compliance has resulted in design packages not receiving approval, leading to time wasted on resubmissions.

- **Uncertain Schedule for Completion:** The current schedule primarily focuses on tasks assigned to the prime contractor. However, there is uncertainty regarding any additional work that may be required due to the constantly evolving design solutions being provided.

- **BESS Electrical Engineer of Record (EoR):** SunGrid has confirmed the party responsible for stamping and sealing the container electrical package and the cable ampacity report. Yukon Energy and the Owners Engineer have reviewed both documents and identified unresolved issues. They have requested meetings with the EoR multiple times, but SunGrid has not yet accepted these requests, resulting in delays in addressing key concerns.

Budget Update

The Yukon Energy Board in its Part 3 Application review examined a total project budget of $34,957,000, which initially included a risk-based contingency of $4,631,000. The Table below outlines the project's budgeted and actual expenditures through Q4 of 2024, showing that the project is on track to meet its budget, including the adjusted contingency.

Table 5.1A-7: BESS Budgeted and Actual Expenditures Through Q4 of 2024 ($000)

Category	Costs to End of December 31, 2024	Forecast at Completion	Board Approved Budget	Variance
Owner's Engineer	893	1050	438	-612
Feasibility & Engineering	822	834	754	-80
Project Management	952	1020	327	-693
Permitting & Assessment	193	207	223	16
Public Engagement & Communications	100	151	124	-27
First Nations Engagement	43	353	156	-197
YEC Internal Labor	648	802	500	-302
EPC Contractor	15,932	26,932	27,128	196
34.5 kV Line Construction	146	146	150	4
AFUDC	971	1,276	526	-750
Subtotal	**20,700**	**32,771**	**30,326**	**-2,445**
Contingency	0	2,186	4,631	2,445
Project Total	**20,700**	**34,957**	**34,957**	**0**

The currently forecasted variances between the approved budget and the forecast is as follows:

- **Project Management/Owners Engineering/YEC Internal Labor:** The overspending in these areas is due to additional work required to address challenges in the main EPC contractor's progress. However, this additional spending is offset by savings in other areas, resulting in an overall project forecast that remains within the approved budget.

- **EPC Contractor:** The variance here stems from a few factors.

  - **Raw Materials Index (RMI) Clause Payment to SunGrid**: A significant payment of approximately $2.5 million under the RMI clause.

  - **Multiple SunGrid Change Orders**: Anticipated change orders amounting to around $445,000, which were previously identified in the risk register.

  - **Contract Amendment Due to Technical Issues**: Due to the contractor's inability to meet technical requirements, SunGrid and Yukon Energy agreed to develop an amendment, settlement, and release agreement that will reduce the contract by $4.7 million and extend the project completion to December 31, 2024. The negotiation of this agreement is ongoing. The value of the settlement has been added to the contingency.

  - **Emergency Backup Generation**: Yukon Energy is procuring two 570 kW mobil backup gensets to power the BESS site in an emergency to avoid the risk of battery degradation. This cost is reflected under the EPC contractor cost line.

Contingency planning: The initial contingency of $4,631,000 has been utilized for the project activities to date. Yukon Energy and SunGrid are currently negotiating a contract amendment, settlement and release agreement that will reduce the contract by $4.7 million. The agreed-upon $4.7 million contract decrease that is under negotiation will be utilized to increase the contingency, ensuring sufficient funds are available to address any further risks that may arise.

Table 5.1A-8: Summary of BESS Contingency Balance

Contingency Event	Amount	Declining Balance
Contingency Event		$4,631,000
Addition of $4.7M for 2025 Contract Amendment	($4,700,000)	$9,331,000
Surveying and Civil Work (Little Rivers/Challenger Geomatics)	$220,000	$9,111,000
SunGrid CO#4: Battery Price Adjustment (50% RMI)	$2,550,000	$6,561,000
SunGrid CO#1 to 9	$445,000	$6,116,000
AFUDC Increase due to Schedule Extension	$730,000	$5,386,000
Additional Engineering and PM Services (Project Extension)	$1,400,000	$3,986,000
Legal Fees (Conflict Resolution/Contract Support)	$400,000	$3,586,000
Purchase of 2 Emergency Gensets	$1,100,000	$2,486,000
First Nation Payment at the end of the project	$300,000	$2,186,000
Contingency Balance		**$2,186,000**

The following table shows major cost components for the BESS on an annual basis.

Table 5.1A-9: Summary of BESS Expenditures by Component (2021- 2024)

Category ($000's)	2021	2022	2023	2024	Forecast 2025
Owner's Engineer	0	192	420	281	157
Engineering	447	69	238	68	12
Project Management	292	196	110	354	68
Permitting & Assessment	65	45	94	-11	14
Public Engagement & Communications	6	26	63	5	51
First Nations Engagement	0	0	43	0	310
YEC Internal Labor	45	122	232	249	154
EPC Contractor	0	8,068	4,368	3,496	11,000
34.5 kV Line Construction	0	130	6	10	0
AFUDC	0	0	501	470	305
Subtotal	**855**	**8,848**	**6,075**	**4,922**	**12,071**
Contingency	0	0	0	0	2,186
Project Total	**855**	**8,848**	**6,075**	**4,922**	**14,257**

Contributions

Through a Federal Government Program, Yukon Energy has a Transfer Payment Agreement with Yukon Government for funding of the Battery Energy Storage System in the amount of $16,500,000. At the time of filing this application, Yukon Energy had received proceeds of $11.9 million, representing collection of all claims submitted for the period ending September 30, 2024.

Project Justification – Part 3 Application

Yukon Energy provided detailed information on project justification and economics in the Part 3 Application.

The original project justification included the current need for dependable capacity to address the N-1 dependable capacity shortfall that requires reliance on rented mobile diesel units to meet Yukon Integrated System reliability requirements. The BESS was to provide 7.2 MW dependable capacity [reduction of four diesel rentals] to reduce Yukon Energy's need to rely on rental of diesel generators during the winter months to address N-1 capacity shortfalls. The BESS was also to provide other benefits, including: an operating reserve that reduces thermal generation requirements; enhanced blackstart capability; opportunities for diesel-peak shifting; and other system benefits. These benefits result in net ratepayer savings when compared to the use of diesel rentals which would be necessary should the Project not proceed. The BESS was expected to assist in YIS grid stability and reduce thermal generation and GHGs – benefiting both the environment and Yukon ratepayers.

The proposed BESS energy and power capacity sizing [20 MW/40 MWh] was to provide 7.2 MW of dependable capacity. Based on displacing winter 2022/23 diesel rental costs of approximately $168,900/MW, the estimated year 1 (2022) annual savings in diesel rental costs approximated $1.216 million per year and these cost savings were assumed to escalate at 4% per year over the 20-year project.

The Hatch August 2020 Report concluded that use of the BESS to provide operating reserve has the greatest economic benefit among the identified additional use cases with benefits of BESS use for operating reserve noted to be two-fold:

- A direct reduction in diesel and natural gas genset operation hours and energy generation; and
- Improved efficiency of the hydro-turbines by operating them at their most efficient output more frequently, leading to more energy production with the same amount of water flow.

When the 20 MW/40 MWh BESS project is used as operating reserve it was estimated to save up to 1,837 MWh of diesel and 17,043 MWh of LNG, or $3.374 million annually, based on 2021 GRA fuel prices. It was also noted that these estimates may not be fully realized due to water storage savings with the existing operations, and that net thermal generation reduction from BESS operating reserve use is approximately one-third of estimates, i.e., the operating reserve annual net fuel cost saving was reduced to approximately $1.125 million (2022$).

As shown in the Part 3 Application, over the life of the project the net present value (2022$) of the costs was estimated at $27.751 million was compared to the net present value of benefits of $40.426 million. This indicated that the Project will benefit Yukon ratepayers (present value savings of $12.676 million).

Project Justification – Updated

Due to the change in the proposed BESS energy and power capacity sizing from 20 MW/40 MWh to 17.5 MW/37 MWh, the amount of dependable capacity provided by the BESS project is expected to be reduced from 7.2 MW to 5.5 MW of dependable capacity. Since the Part 3 Application, other costs and benefits have also changed. The table below shows an updated analysis that over the life of the project the net present value (2025$) of the costs is $30.234 million compared to the net present value of benefits of $40.647 million. This indicates the Project will benefit Yukon ratepayers (updated net present value savings of $10.413 million).

Table 5.1A-10: Updated Cost Benefit Analysis for the BESS

	BESS Annual Costs ($000)				BESS Annual Savings ($000)				
$000	Annual Capital Cost	Annual Operating Cost [excl. recharging]	Annual Net Recharging Cost [15% return loss plus 3% idling loss]	Total Annual Costs	Avoided Diesel Rental Costs	Annual Savings from Operating Reserve Use	Annual Savings from Peak Shifting	Total Annual Savings	Net Annual Ratepayer Savings (Costs) ($000)
	A	B	C	D=A+B+C	E	F	G	H=E+F+G	I=H-D
Year 1	$2,073	$678	$120	$2,870	$1,142	$1,576	$25	$2,742	-$128
Year 2	$2,014	$691	$122	$2,826	$1,187	$1,607	$25	$2,820	-$7
Year 3	$1,955	$704	$125	$2,783	$1,235	$1,639	$26	$2,900	$117
Year 4	$1,896	$717	$127	$2,740	$1,284	$1,672	$26	$2,983	$242
Year 5	$1,837	$731	$130	$2,698	$1,336	$1,706	$27	$3,068	$370
Year 6	$1,778	$745	$132	$2,655	$1,389	$1,740	$27	$3,156	$501
Year 7	$1,719	$759	$135	$2,613	$1,445	$1,774	$28	$3,247	$634
Year 8	$1,660	$774	$137	$2,572	$1,502	$1,810	$28	$3,341	$769
Year 9	$1,601	$789	$140	$2,530	$1,562	$1,846	$29	$3,438	$907
Year 10	$1,542	$804	$143	$2,489	$1,625	$1,883	$30	$3,538	$1,048
Year 11	$1,483	$820	$146	$2,449	$1,690	$1,921	$30	$3,641	$1,192
Year 12	$1,424	$835	$149	$2,408	$1,758	$1,959	$31	$3,747	$1,339
Year 13	$1,365	$851	$152	$2,368	$1,828	$1,998	$31	$3,858	$1,489
Year 14	$1,306	$868	$155	$2,329	$1,901	$2,038	$32	$3,971	$1,642
Year 15	$1,247	$885	$158	$2,290	$1,977	$2,079	$33	$4,089	$1,799
Year 16	$1,188	$902	$161	$2,251	$2,056	$2,121	$33	$4,210	$1,959
Year 17	$1,129	$919	$164	$2,213	$2,138	$2,163	$34	$4,335	$2,123
Year 18	$1,070	$937	$168	$2,175	$2,224	$2,206	$35	$4,465	$2,290
Year 19	$1,011	$955	$171	$2,137	$2,313	$2,250	$35	$4,599	$2,461
Year 20	$952	$973	$174	$2,100	$2,405	$2,295	$36	$4,737	$2,637
NPV	**$19,289**	**$9,293**	**$1,652**	**$30,234**	**$18,559**	**$21,746**	**$342**	**$40,647**	**$10,413**

Notes:

1 Capital costs at $34.9 million offset by a $16.5 million grant. Column A shows annual depreciation and return on rate base.

2 YEC WACC at 6.39% based on the assumption in the upcoming 2025-27 GRA with a new debt rate.

3 Avoided Diesel Rental Costs assume $208k/MW based on total diesel rental cost of $7.0 million and 5.5 MW of dependable capacity for BESS.

4 Annual Savings from Operating Reserve Use and Peak Shifting are based on BESS Part 3 Hearing estimates updated with the most recent fuel costs [LNG at $0.2482/kWh and diesel at $0.3219/kWh based on the assumptions for the upcoming 2025-27 GRA].

Project In-Service

In the context of financial reporting and impacts on YEC's net rate base, the in-service date is impacted by when the asset is capable of being used as intended. Commissioning is a part of the process that verifies this readiness. Until commissioning is complete, the asset is not considered available for use, and its in-service date (which triggers depreciation) would be delayed. Further, as described below, Yukon Energy expects additional activities to be required after commissioning before the BESS can be available to provide dependable capacity that reduces the need for diesel rentals.

As part of the 2023/24 GRA, in response to JM-YEC-1-5, Yukon Energy noted that it expects that at least one winter season of testing is required to fully understand the BESS capabilities to provide dependable capacity and other ancillary services such as spinning/operating reserve.

In response to NY-YEC-1-5 in the 2023/24 GRA, Yukon Energy noted that the project is not currently in the projected costs for test year revenue requirements due to delays that to date prevent the BESS from displacing diesel rental requirements during the test years.

The BESS is now scheduled by the contractor to be commissioned in Q4 2025. The project schedule has undergone significant revisions since its initial development. The most recent update, provided by SunGrid on December 5, 2024, shifted the final completion to August 7, 2025. It should be noted that the most recent schedule already includes multiple missed target dates. SunGrid's latest schedule lacks details on further construction due to design changes, suggesting additional delays are likely.

When SunGrid's work is complete, Yukon Energy is expecting to take over a site that most likely will need improvements and upgrades to make up for all the non-critical deficiencies, such as structural, communication, and protection and control changes that are expected. In addition, this is a new type of asset for Yukon Energy. It will take some testing on the Operations side to get comfortable using it. In summary, the project will not reduce the number of mobile diesel rental units required in winter 2025-26.

In summary, consistent with the reasons provided in the 2023/24 GRA, the BESS will not be considered in-service as of December 31, 2025 as it is not yet ready for its intended use and significant further commissioning and testing is required and the facility will not be fully functional or providing the expected benefits. The current GRA forecasts actual in-service and resulting reduction of diesel rentals in winter 2026/27.

5.1A-3: MH0 ROCKSLIDE STABILIZATION AND REMEDIATION

Table 5.1A-11: MH0 Rockslide and Stabilization and Remediation Costs Added to Ratebase

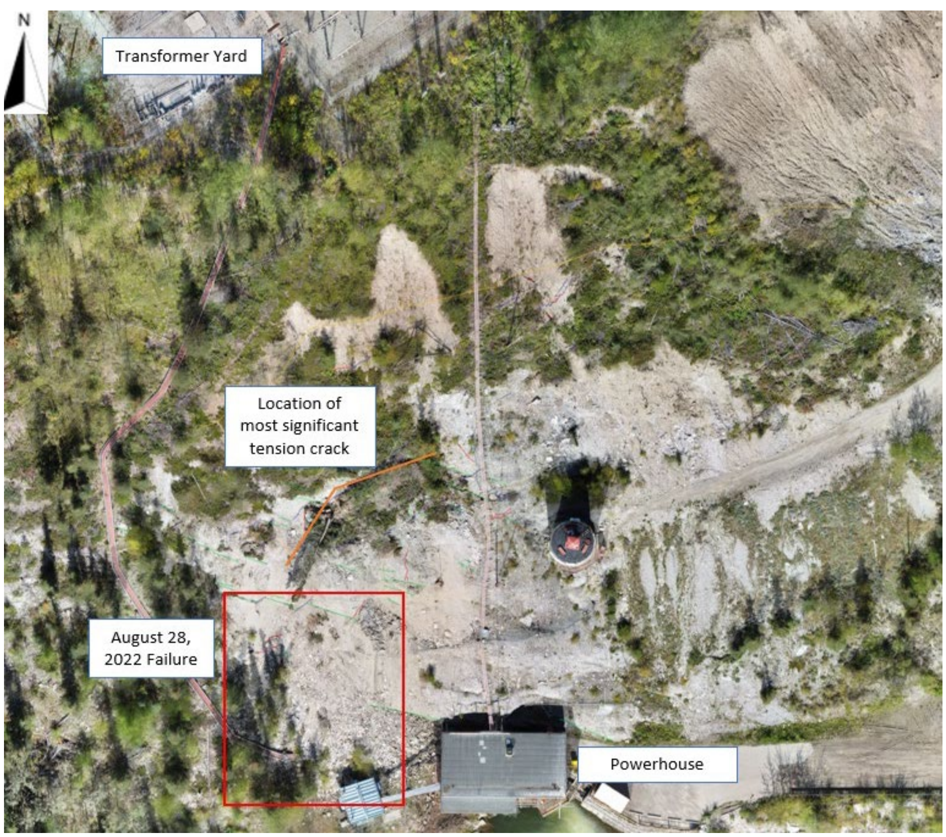
Opening WIP	2025	2026	2027	Total Additions
$3,187,900	$42,242,100	$33,214,600	$0	$78,644,600

Project Description

The project stabilizes and remediates the rock slope above the Mayo 0 (Mayo A) powerhouse by the end of 2026, providing protection for an expected life of 100 years against the near-term risk of rockslides that would severely impact both Mayo A and Mayo B hydro facilities and also adversely affect required flows for the water license and fish passage.

Figure 5.1A-1 provides an overview of the relevant Mayo A facilities affected by the current near-term rockslide risk, including the powerhouse at the bottom of the slope (with the penstock supplying water to both Mayo A and Mayo B powerhouses), the Mayo A surge chamber located mid-way up the slope to the right above the powerhouse, and the substation yard for Mayo A and Mayo B at the top of the rock slope.

Figure 5.1A-1: Overview of Mayo A Facilities affected by Slope Instability



Need for the Project Today

The Mayo Rock slope is a 75 m high rock slope located above the MH0 plant and below Substation S249. The slope has been deteriorating for several years as evidenced by the ongoing rockfall and localized instability events. The recent rockslide events are outlined below.

- A rockslide event occurred in 2015, and the powerhouse was damaged by falling rocks. In response to this, Yukon Energy installed energy barriers on the slope in 2016/17.

- On August 28, 2022, there was another rockslide event with a debris volume of around 1000 m^3. The energy barriers helped protect the powerhouse, however, they were partially destroyed by the event and the switching shack was damaged. At this time, the plant was shut down and the slope was assessed.

- In June 2023, another rockslide event occurred. The powerhouse was impacted with debris but did not sustain damage.

Several hazard analyses have been completed on the slope, and some remediations have been implemented to address the low and medium hazard items. Remediations include the installation of rock fall containment, mesh system, and monitoring prisms.

Following rock slides above the Mayo A powerhouse in 2022 and 2023, an assessment of the slope revealed a high potential for catastrophic failure in the near future that would severely impact both the Mayo A and Mayo B hydro facilities. A large failure event has the potential to cover the Mayo A plant, damage the Mayo A surge chamber, the substation for both Mayo A and Mayo B, and the Mayo A penstock, and block the Mayo River.

Closure of the Mayo A plant due to further rock slides would also affect regulatory requirements, as Yukon Energy would be unable to maintain the required flows for the water licence and fish passage.[4] Temporary rock slope mitigations were put in place in 2023 to protect the Mayo A plant from the risk of rock fall. Full slope stabilization is required as soon as feasible to protect the plant from a global failure which could be catastrophic.

[4] Yukon Energy is required to pass water through the Wareham Dam Structure or the Mayo A plant to meet water licence requirements and ensure that the upper portion of the river has fish flows. The Wareham Dam is not currently able to pass flows during the winter, so flows during winter must be passed through the Mayo A plant. Spray from the spillway can freeze during winter operation, with ice buildup potentially becoming heavy enough to cause the spillway structure and access bridge to fail.

When the temporary mitigations were put in place, Tetra Tech performed a slope investigation to establish the risk and prepared a design for the permanent mitigation. The estimated Factor of Safety (FoS) of the rock slope, as calculated by Tetra Tech, is near 1.0, indicating that the rock slope has a high potential for a failure in the near future.

Tetra Tech's risk assessment in 2023 looked at the risk of delaying the permanent rock slope mitigation for 1 year (2025) or three years (2027). Table 5.1A-12 below shows that the risk of delaying the work until 2027 is high in all categories, except for global slope failure which is a medium risk.

Table 5.1A-12: Mayo Rockslide Risk Assessment Matrix for One & Three Years Delay

	Scenario 1 – 1 Year Delay (to 2025)				Scenario 2 – 3 Year Delay (to 2027)			
Risk	Likelihood	Consequence		Risk Rank	Likelihood	Consequence		Risk Rank
		Cost	Outage Duration			Cost	Outage Duration	
Risk 1 – Global Slope Failure	Low	Very High	Very High	Medium	Low	Very High	Very High	Medium
Risk 2 – Local Scale Rockslide	Low	High	Very High	Medium	Medium	High	Very High	High
Risk 3 – Rockfall (Area without support)	Very High	Low	Medium	High	Very High	Low	Medium	High
Risk 4 – Rockfall (Area with support)	Medium	Medium	High	Medium	Very High	Medium	High	High

Tetra Tech collected the latest slope monitoring data in March 2025. This data was used to update the probability of failure. The updated probability is outlined below in Table 5.1A-13. If work is delayed for 12 months the probability of a large failure, that would shut the facility down, is nearly 6%, this increases to almost 11% after 18 months.

Table 5.1A-13: Probability of Failure Based on March 2025 Data Collection

Failure Scale	~Volume (m3)	Probability of Collapse in Months				
		6	12	18	24	36
Overall	30,000	0.0%	0.0%	0.0%	0.1%	0.3%
Large	15,000	2.3%	5.6%	10.8%	17.9%	35.1%
Spider Mesh	1,500	1.2%	26.9%	82.5%	100.0%	100.0%
Small	500	41.8%	99.9%	100.0%	100.0%	100.0%

A cost benefit assessment of Mayo A rock slope remediation combined with Mayo A surge chamber replacement and Mayo A powerhouse replacement (see below) confirms the overall net benefit of retaining Mayo A powerhouse capabilities for the next 75+ years versus the option of measures to replace Mayo A with thermal generation and retain ongoing Mayo B operation without Mayo A rockslide stabilization and remediation.[5] Based on the above, it is prudent that Yukon Energy design and implement a permanent solution to the rock slope failure as soon as possible to provide protection for operations of the overall Mayo Generating Station facility.

Options Assessment

Six slope mitigation design options were evaluated through a Multiple Account Analysis (MAA) framework that considered factors such as safety, cost, environmental impact, and technical feasibility. Following the MAA, two options were advanced for more detailed assessment and consideration.

For each option, a brief material take-off (MTO) was developed, which included the type and approximate number of necessary anchors, the estimated cut and fill volumes, and necessary ancillary work. Work that was common to all options (site preparation and clean up, for example) was not considered. The brief MTO was used to inform a Class V cost estimate that was developed for each option.

The MAA considered the resulting construction cost for each option, along with 11 other variables related to construction, potential for adverse impacts to other infrastructure, long-term costs, and risks related to construction and long-term performance.[6]

- From the MAA the two options selected were:

[5] In order to retain Mayo B operation without Mayo A rockslide stabilization and remediation, it would be necessary to move or otherwise protect the substation facilities from rockslide instabilities, decommission Mayo A, and plug the Mayo A penstock upstream of the surge chamber.

[6] Details regarding the methods, components, ratings, and scoring of the MAA can be found in Technical Report No. "5954051-002000-40-ERA-0002" provided by BBA on January 26, 2024.

- **Extensive Bolting (the selected option)**

  This option involved scaling the loose material from the surface of the slope above the powerhouse, installing dowels on a 3m x 3m spacing to stabilize the potentially unstable mass by anchoring it to deeper stable rock and installing mesh on the surface of the slope. In this design the rockfall control fences that were installed during the temporary protections are retained to provide an additional layer of protection.

- **Hybrid Tie-back and MSE Wall at the Toe**

  This option involved scaling some of the loose material from the upper half of the slope above the powerhouse to reduce long term potential for debris flows and installing a wall at the toe of the slope. The design included a tie-back wall that would be constructed behind the powerhouse and on the eastern side of the powerhouse. Additionally, an MSE wall would be constructed on the western side of the powerhouse. A minor anchoring scope was also included in this option.

- These designs were brought to 20% design with class 4 cost estimates. The MAA was updated for these two options and extensive bolting was selected as it had a better overall score. This is in part to a lower estimated cost and a shorter estimated construction schedule. Additionally, the potential risks associated with the tie-back wall contributed to the decision to proceed with the Bolting option. The risks of the tie-back wall included the risk of installing piles near the penstock and the risk of encountering constructability challenges.[7]

The primary option was taken to 100% design and tendered with the surge chamber work in 2024. Three bids were received. Only two submissions met the minimum technical compliance score. Tender submission review is completed, and the final contract award is proceeding at the time that the 2025-2027 GRA is being finalized. The proposed budget and project cost assessments in the 2025-2027 GRA reflect the submission that received the highest overall evaluation score with a binding price which provides a clear and firm commitment to Yukon Energy.

Rockslide Stabilization and Remediation Project Expected Capital Costs and In-Service Date

Table 5.1A-14 below provides details on the MH0 Rockslide Stabilization and Remediation Project expected capital cost of $78.645 million for planned in-service in 2026.

[7] Details regarding the methods, components, ratings, and scoring of the updated MAA and final option selection can be found in Technical Report No. "5954051-002000-40-ERA-0003 " provided by BBA on April 04, 2024.

Table 5.1A-14: Expected Capital Costs for MH0 Rockslide Stabilization and Remediation Project – Includes Tariff Contingency

Items	2023-2024 ($000's)	2025 ($000's)	2026 ($000's)	Total ($000's)
Contractor	1,332	35,000	25,000	61,332
Consultant	1,580	550	575	2,705
YEC Internal Cost	189	175	200	563
Materials	9			9
Subtotal	**3,110**	**35,725**	**25,775**	**64,610**
AFUDC	78	536	1,458	2,072
Contingency		5,981	5,981	11,963
Total	**3,188**	**42,242**	**33,215**	**78,645**

Award of construction for the project is expected in April 2025. Construction is to be completed in 2025 and 2026 construction seasons. Project in-service is expected in fall 2026, following completion of construction.

All the construction work is planned to occur on Yukon Energy property and out of the water. No permitting is required for this work. The contractor will be responsible for complying with all applicable Territorial and Federal regulations, including tree clearing regulations.

Project Justification and Cost – Benefit Assessment

The MH0 Rockslide Stabilization and Remediation Project, along with the MH0 Surge Chamber Replacement, are required to retain the future operation of MH0 plant generation versus removal or relocation of this plant and returning the site to near greenfield condition. The project justification assessment has therefore looked at this broad range of overall options.

Yukon Energy has developed business cases over the years to plan for the replacement of MH0 and related assets. As the rock stabilization work and surge chamber replacement became more urgent this work has been prioritized, and a cost benefit analysis has been developed.

Previous condition assessments of the MH0 plant have identified a significant amount of deterioration as well as obsolete equipment and infrastructure. The hydro-mechanical equipment, balance of plant systems, power plant building, tailrace structure, surge chamber and both horizontal Francis hydro generators are nearing the end of life and Yukon Energy has begun to look at potential future options to replace or refurbish the MH0 plant.

In 2016, Yukon Energy commissioned KGS Group (KGS) to write a report to investigate options to replace or refurbish the MH0 plant and rank them in terms of net present value to Yukon Energy. This report included slope stabilization measures and surge chamber replacement costs. In 2019, this report was updated to reflect the latest condition information collected during the 2018 overhaul and updated options and costs.

In 2024, this report was further updated to reflect the recent volatility in the market, and the understanding that the surge chamber replacement and slope stabilization would have to be conducted before other work could take place.

The reports examined several options including the following:

- Replacing the MH0 station;
- Refurbish MH0 and replace Unit 2;
- Refurbish MH0, refurbish Unit 2 now, and replace the unit in 2036;
- Refurbish MH0 and Replace both units;
- Refurbish MH0 refurbish both units now, and replace the units in 2036;
- Remove the plant and return the site to near greenfield; and
- Abandon the plan in-situ.

The results of this report were combined with the updated surge chamber and rock stabilization costs to develop a cost benefit analysis. The cost benefit analysis examines the benefit of carrying out the slope stabilization work, the surge chamber replacement work and replacement of MH0 in some capacity vs. abandonment of the plant and slope and re-location of the substation. The results of the cost benefit are outlined below in Table 5.1A-15 (see Attachment 5.1A-1 for added details).

Table 5.1A-15: Total NPV of Cost Benefits over 75 years ($000; 2025$)

	Costs	Avoided Costs	Net Benefits
Total NPV (15.7 GWh)	$165,082	$228,998	$63,916
Total NPV (9.2 GWh winter generation)	$165,082	$180,227	$15,145

Based on the cost benefit, the financial viability of the rock slope and surge chamber projects, along with the Mayo A plant replacement, depends heavily on annual thermal displacement and substation relocation assumptions.

The MH0 plant produces 15.7 GWh annually based on the base load of the plant and the amount of water that must be passed to meet the water licence requirements. If the plant is replaced Yukon Energy would anticipate that this generation rate would continue or expand. There is currently work underway to examine the possibility of allowing more flow through the penstock, which would increase the MH0 power production. Based on this rate of generation and accounting for avoided costs like a new diesel plant and substation relocation the project results in a NPV of $63.9 million.

If only the winter generation of MH0 is replaced with thermal the NPV is $15.1 million. This assumes Yukon Energy can continue in the future (as is the case today) to replace the MH0 summer generation with other sources such as surplus hydro generation from other Yukon Energy facilities and from renewable IPPs. However, the summer generation of MH0 could be required in the future as more demand comes online for the YIS, summer demand increases, and Yukon Energy looks at the possibility of hydro backed pump storage.

The decision to retain or abandon the MH0 hydro plant extends beyond cost considerations, with significant implications for energy reliability, environmental sustainability, and grid stability. MH0 plays a crucial role in providing reliable and green energy to the Yukon grid, particularly for the north. Given the current infrastructure and resource limitations, it is highly unlikely that this hydro generation could be replaced elsewhere in the system with green energy in the foreseeable future. The small units at MH0 offer vital operational flexibility, helping to balance fluctuations in energy demand and ensuring consistent power supply.

Since its addition to the grid in the 1950s, MH0 has been a dependable energy source, running almost continuously to support the Yukon's electricity needs. Hydropower forms the backbone of winter electricity supply, making legacy hydro facilities, like MH0, essential. These facilities have enabled the Yukon to produce an average of over 90% of its electricity from hydro over the last 25 years. Maintaining this level of renewable energy generation requires proactive investment in infrastructure to ensure ongoing efficiency and reliability while minimizing environmental and social impacts. Preserving MH0 is an investment in the Yukon's energy future.

MH0 is also a critical resource in restoring service to the northern grid in the event of outages. If the northern part of the grid becomes islanded, MH0's power can be directed to support communities such as

Mayo and Dawson, playing a key role in frequency control and overall grid stability. The plant's robust design and decades of consistent operation demonstrate its value to the Yukon's energy system.

Water management is also a crucial factor in this decision. Under the conditions outlined in the water licence, flow must be maintained between MH0 and Mayo B. This can be achieved by passing water through MH0, generating power or by spilling the water. If MH0 were abandoned, all water would have to be spilled, resulting in the loss of a renewable energy source. Rather than wasting this resource, continued operation of MH0 allows for optimal use of available water while contributing to the Yukon's clean energy goals.

Conclusion

In summary, the retention of MH0 is essential for maintaining energy security, ensuring environmental responsibility, and supporting the long-term sustainability of the Yukon's hydroelectric system. Investing in its continued operation will safeguard the region's energy resilience and uphold the legacy of hydropower that has served Yukoners for decades.

Attachment 5.1A-1: MH0 Rockslide Stabilization and Remediation Cost Benefit Assessment of Retaining Mayo A Powerhouse Capabilities

Cost Benefit:

Alternatives Considered:

- Completing the rock slope remediation, plant replacement, surge chamber replacement; and
- Moving the substation (in part or full), abandoning the plant and replacing the generation with new diesel.

Table A-1: Cost Benefit Analysis

	($000; 2025$)	Costs	Avoided Costs	Net Benefits (Costs)
	NPV of Rock Slope and Surge Chamber	*$112,332*		
	NPV of Mayo A Replacement [2.5 MW]	*$52,750*		
	NPV of Avoided New 2.5 MW Diesel Plant Capital Cost		*$9,123*	
	NPV of Avoided Diesel Fuel Cost over 75-years [9.2 GWh with 2% inflation]		*$68,704*	
	NPV of Avoided Substation Relocation		*$77,830*	
	NPV of Avoided Abandoning of Mayo A in Situ Costs		*$24,569*	
A	**Total NPV of Costs/Benefits over 75 Years**	**$165,082**	**$180,227**	**$15,145**
	Sensitivity Analysis			
B	Total NPV with higher Thermal Displacement *[at 15.7 GWh vs 9.2 GWh]*	$165,082	$228,998	$63,916

Notes:

- The MH0 Rock Slide Remediation work will protect the MH0 plant, the surge chamber and the substation.
- The surge chamber is only required for Mayo A. However, as both penstocks are connected and there is no way to isolate the penstocks. A failure of the surge chamber today would require a closure of both plants. If Mayo A is abandoned, the surge chamber will need to be decommissioned and the Mayo A penstock permanently plugged. This will not have a negative impact on Mayo B.

The sources for the costs used in the cost benefit are:

- **Slope Remediation and Surge Chamber Replacement**: Cost is based on actual costs from the Yukon Energy RFP Submittals received in December 2024.

- **MH0 Plant Renewal**: Cost is based on the net present value for replacing the MH0 plant and one unit. This was estimated to cost $50 million (Class 4) (KGS 2024).

- **S249 Substation Re-location**: Cost is based on the Class 5 estimate to relocate the substation that was prepared by KGS and their 3rd party cost estimator. They estimated a cost of $74 million.

- **MH0 Plant Abandonment**: Cost is based on the capital cost for abandoning the MH0 plant in-situ based on KGS's 2024 estimate and $20 million in costs to provide some stabilization of the slope above the abandoned plant.

- **Cost of a new 2.5M Diesel Plant**: Capital cost of $8 million is based on recent diesel generator projects Yukon Energy conducted.

Assumptions:

- Mayo A hydro generation at 15.7 GWh based on the base load of the plant and the amount of water that must be passed to meet the water licence requirements.

- Mayo A hydro generation at 9.2 GWh based on the base load of the plant and the amount of water that must be passed to meet the water licence requirements in the winter months.

- Fuel costs were assumed to be $311/MWh based on approved fuel price for Mayo in the 2023/24 GRA.

- Weighted Average Cost of Capital 6.2%.

Risks:

- Construction costs for the rock slope and surge chamber increase during construction.

- Estimated costs are higher than estimated:

    - The cost to replace the MH0 plant is higher than estimated;

    - Abandonment costs are higher than estimated; and

    - Thermal cost fluctuates in the future.

- Yukon Energy will be required to replace thermal generation with renewable generation in the future, which will require further investment.
- Rock slope failure damages the substation.
- Rock slope failure impacts the river and causes environmental damage or blocks flow.
- Loss of reliable capacity and frequency control causes power production or distribution issues.

5.1A-4: WAREHAM DAM SPILLWAY – TUNNEL

Table 5.1A-16: Wareham Dam Spillway – Tunnel Costs Added to Rate Base

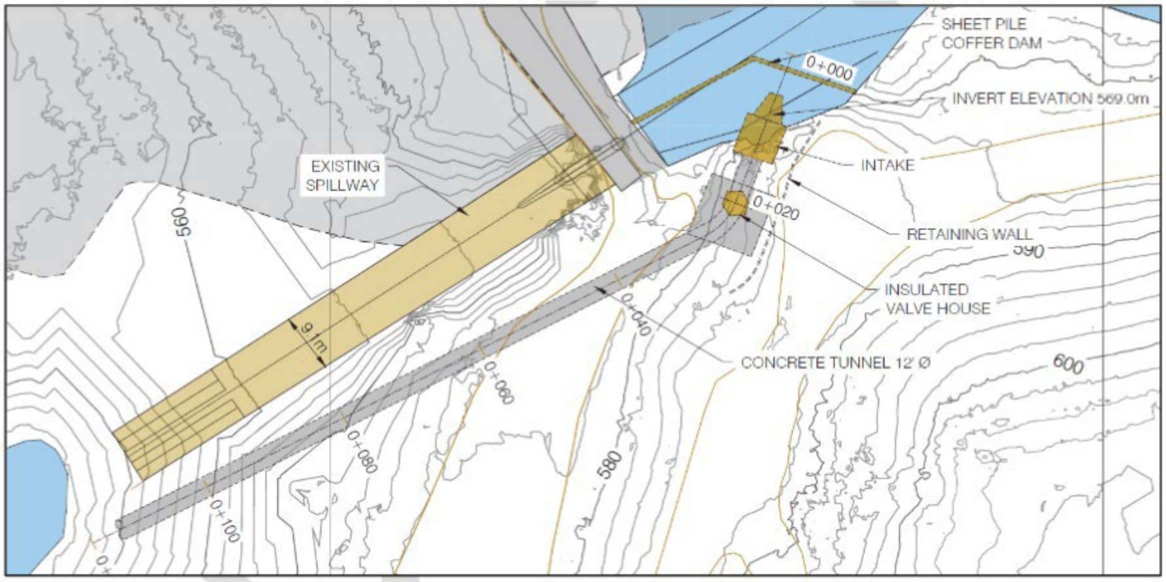
Opening WIP	2025	2026	2027	Total Additions
$3,712,000	$5,221,400	$35,914,800	$29,076,000	$73,924,100

Project Description

The project provides a new permanent Wareham spillway tunnel with an expected life of 75 years to facilitate the safe passage of water over the Wareham Dam facility to meet Inflow Design Flood (IDF) requirement at the Mayo Generating Station. A tunnel spillway will be constructed within bedrock on the left abutment (looking downstream). This structure will be used to convey water during a subsequent second permanent repair project to replace the existing spillway by 2029, and thereafter the tunnel will serve as the primary operational spillway for the Wareham Dam (the replaced existing spillway will function as the secondary or auxiliary spillway). The new permanent spillway repair will be sufficient for the Wareham Dam's updated IDF of 590 m^3/s versus the 425 m^3/s design capacity for the current spillway. Additional infrastructure improvements with both new permanent spillway structures include plunge pool enhancement (included with current GRA to improve energy dissipation and reduce erosion) and downstream fish passage improvements.

Figure 5.1A-2 shows the existing Wareham spillway and the Wareham Dam Spillway tunnel project to be installed on the left abutment.

Figure 5.1A-2: Wareham Dam Spillway Project Tunnel



Need for the Project Today

The Wareham spillway was originally commissioned in 1952. It provides the IDF capacity to the Wareham Lake system required for operation of the Mayo Generating Station (both the original Mayo A [or Mayo 0] facility commissioned in 1952, and the new Mayo B facility commissioned in 2011). 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 it is the main failure mode of earthfill dams. Therefore, the inoperability of the spillway during flood increases the risk profile of the Wareham Dam significantly.

As reviewed in Yukon Energy's 2023/24 GRA, interim concrete repairs have been required at the Wareham spillway for many years until the spillway could be permanently repaired.[8] Following the gates being deemed at the end of life in 2019 and failure of the concrete overlapping slab in 2020,[9] the subsequent need was established for annual interim repairs to maintain operation of a chute at its end of life.

[8] The 2023/24 GRA resulted in $1.845 million costs being added to rate base for interim repairs to the spillway between 2020 and 2023. Interim repair with a 5-year life and monitoring were implemented before the 2021 spring freshet to avoid further damage and manage failure risk until permanent repairs can be completed. The 2023/24 GRA business case for these repairs reviewed relevant spillway history, including: issues arising from a summer 2020 project to rehabilitate one of the spillway gates; the 2002 Dam Safety Review that identified requirements for concrete overtopping over the spillway chute (and subsequent issues arising from the hoarding and construction techniques implemented); issues identified over the 1960s through the 1980s regarding erosion of the foundation under the chute, wearing of the concrete surface, constant repairs of the spillway chute (five projects executed from 1970 to 1987 to gout cracks), and movement of the spillway walls noted in 1970 and addressed in 1976.

[9] A concrete overtopping project was initiated in 2004 based on recommendations from the 2002 Dam Safety Report.

The need for a permanent solution as soon as possible has also been recognized for many years - aside from significant annual costs with a very limited lifespan and inability to address a range of structural risks inherent in end of life facilities[10], annual repairs cannot address the need to increase the Wareham Dam's original design capacity from its existing 425 m^3/s to the updated required IDF of 590 m^3/s.[11]

Yukon Energy has been actively working towards a permanent solution as soon as possible, undertaking conceptual option development, multiple account analysis of options, and site investigations to determine the most effective, cost-conscious, and timely solutions. Commitment to proceed also required regulatory planning and securing approvals and funding.

The Wareham spillway tunnel project (Stage 1 of 2) now initiates the implementation of the needed permanent solution. The tunnel will provide the opportunity to pass water when the existing spillway is being replaced during Stage 2 and, when combined with Stage 2 replacement of the existing spillway, will provide for the required increase in IDF.

Options Assessment – Rationale for Selected Permanent Solution

Eight conceptual options were initially developed for the permanent spillway solution. These options were evaluated through a Multiple Account Analysis (MAA) framework that considered factors such as safety, cost, environmental impact, and technical feasibility. Following the MAA, two options were advanced to the 30% design stage with the development of a Class 3 cost estimate (-20%/+30%):

- **Option 3** – Consisting of a buried pipe on the right abutment with full replacement of the existing spillway; and

- **Option 7** – Consisting of a tunnel within bedrock on the left abutment with full replacement of the existing spillway.

Option 7 was selected as the preferred solution, offering the most favourable balance of safety, feasibility, and cost effectiveness[12]. Below is a high-level summary comparing the two options.

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[10] Stantec provided a 2023 memo to Yukon Energy highlighting the risk exposure to Yukon Energy from deferral of permanent Wareham Spillway repairs/replacement, and the suggested urgency to proceed with the permanent solution.
[11] While the spillway was initially designed to accommodate a flow of 425 m^3/s, recent studies suggest that the probable maximum flood (PMF) could reach as high as 599 m^3/s (WSP-2022). Additionally, the updated IDF now stands at 590 m^3/s (including climate change impact), exceeding the original design capacity. With the spillway's discharge capacity estimated at approximately 400 to 430 m^3/s, there is a clear discrepancy between its capabilities and the anticipated flood discharge.
[12] BBA Letter Report, "Owner's Engineer's position on the preferred option for the Wareham Dam Spillway Project", February 2025.

Table 5.1A-17: Comparison of Option 3 and Option 7

	Option 3	Option 7
Cost Estimate – Class 3	This option carries an estimated additional cost of approximately $30 million.	
Fish Passage Improvement	Similar opportunities.	Similar opportunities.
Associated Risks	• Slop stability. • Groundwater ingress. • Potential deformation around the intake and pipeline. • Construction near the core of the dam. • Excavation at the dam downstream toe. • Access to the furthest point of the facility for the construction.	• Steep tunnel gradients. • Face/crown collapse of the tunnel. • Challenges in managing groundwater ingress.
While both options require extensive risk management, the risks in Option 7 are generally more manageable and easier to mitigate due to the standardized and mature methodologies available for tunneling and rock support.		
Schedule	Similar timeline.	Similar timeline.

In recognition of the significant expected overall capital cost for the selected permanent solution for the Wareham Dam spillway (i.e., costs approaching $150 million for all stages), Yukon Energy also looked at costs for decommissioning the Mayo Generating Station as this would be the only feasible option to not proceeding with a permanent solution for the spillway. Ignoring costs to provide replacement power for the Mayo A and Mayo B hydro that would be decommissioned (and the time needed to develop equivalent new renewable generation), the cost of simply decommissioning the Mayo Generating Station and restoring Wareham Lake and the Mayo River has been estimated at up to $440 million.[13] Yukon Energy concluded that the selected spillway permanent solution project was clearly preferable to the option of having to decommission the Mayo Generating Station.

The selected spillway permanent solution is to be developed in three phases, with costs for the spillway tunnel and plunge pool being included in the current 2025-2027 GRA:

- **Phase 1 – Design & Procurement (2025)** – Completed detailed design for tunnel and replacement spillway; procure general contractors for the construction of spillway tunnel and

[13] Stantec memo, "Conceptual Screening Study – Cost of Decommissioning the Mayo Generating Station", February 2024. Stantec memo provides an estimate of $80 to 200 million for the decommissioning of the MGS and restoring Wareham Lake and the Mayo River. It is important to note that the cost estimate is class 5 which carries a high level of uncertainty (range of -20% to -50% at low end and +30% to +100% at the high end). Additionally that cost does not account for the replacement of the renewable generation and does not account for the complexity of executing such a project in the remote northern environment of Mayo (>20-25%). Furthermore, there is limited information or precedent available regarding the full decommissioning of a facility like MGS, adding to the complexity and uncertainty of this option and the cost presented within the memo.

plunge pool; and procurement for design, fabrication, supply and technical support for the gates of both spillways.

- **Phase 2 – Project Execution – Spillway Tunnel & Plunge Pool (2026-2027)** – Construction of the spillway tunnel and the plunge pool, and installation of spillway gates for safe and controlled water conveyance at the tunnel spillway.

- **Phase 3 – Project Execution – Replacement of the Existing Spillway (2028-2029)** – Procurement and construction of the replacement spillway, including gates, and ensuring all final integrations align with long-term operational and safety requirements.

Spillway Tunnel Project Expected Capital Costs and In-Service Date

Table 5.1A-18 below provides details on the Wareham Dam Spillway Tunnel Project (including plunge pool) expected capital cost of $73.924 million for planned in-service in 2027.

Table 5.1A-18: Expected Capital Costs for Wareham Dam Spillway Project - Tunnel

Items	2024 ($000's)	2025 ($000's)	2026 ($000's)	2027 ($000's)	Total ($000's)
Contractor		750	23,515	23,000	47,265
Consultant	2,743	3,345	534	489	7,111
YEC Internal Cost	303	150	150	150	753
Materials	640		5,000		5,640
Subtotal	**3,686**	**4,245**	**29,199**	**23,639**	**60,769**
AFUDC	26	127	876	709	1,738
Contingency	0	849	5,840	4,728	11,417
Total	**3,712**	**5,221**	**35,915**	**29,076**	**73,924**

Final design and procurement for the spillway tunnel project is planned to be concluded in 2025. With respect to regulatory processes, Yukon Energy is moving the project forward as an emergency (i.e., urgency requirements) and is therefore submitting a request for amendment to the existing authorizations. Construction is targeted to commence in Q1-Q2 of 2026, following design completion in Q3 of 2025 and selection of contractor and award of contract in Q4 2025. Planned construction completion and commissioning is in Q4 of 2027.

5.1A-5: MH0 SURGE CHAMBER REPLACEMENT

Table 5.1A-19: MH0 Surge Chamber Replacement Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$1,211,500	$2,624,000	$23,995,300	$0	$27,830,700

Project Description

The project replaces, before the end of 2026, the MH0 (Mayo A) surge chamber located on the rock slope above the Mayo A powerhouse, with a new facility having an expected life of 75 years. The new facility will be a "like for like" replacement in the same location, carried out concurrently with the MH0 Rockslide Stabilization and Remediation Project by the same contractor for both projects. A mechanical plug will be used to isolate the surge chamber, allowing it to be removed and replaced in the dry, ensuring constructability and safety while allowing the joint penstocks to remain full and Mayo B to continue to operate while the surge chamber is replaced.

Need for the Project Today and Project Justification

The Mayo A surge chamber was originally commissioned in 1952 and has been assessed to be at the end of its life with significant corrosion, coating failure, and leakage. Recent failures have been addressed using temporary repairs to avoid unplanned outages. Multiple areas on the external shell of the Surge Chamber have been identified that are only 1-2 mm thick and could fail and cause leakage without warning. The MH0 Surge Chamber is located above the MH0 powerhouse and has a free surface of water that is maintained at a similar elevation to Wareham Lake. Therefore, there is a large amount of pressure at the base of the Surge Chamber when Mayo Hydro is in service. Repairs when either MH0 or Mayo B are in service may not be possible due to the water pressure which creates a large risk of a forced outage if any failures occur.

The surge tank protects the Mayo A plant from sudden changes in pressure in the system. As both the Mayo A and Mayo B systems are connected through a shared intake and there is today no way to isolate the systems, a failure of the Mayo A surge chamber would lead to a complete loss of generation from all Mayo hydro facilities, until repairs are made, or a plug can be installed in the penstock portion supplying the Mayo A plant. Closure of the Mayo A plant due to surge tank failure could also affect regulatory requirements, as Yukon Energy may be unable to maintain the required flows for the water licence and fish passage.[14]

A cost benefit assessment of Mayo A surge chamber replacement combined with Mayo A rock slope remediation and Mayo A powerhouse replacement (see Mayo 0 Rockslide Stabilization and Remediation Project business case, cost-benefit assessment and Attachment 5.1A-1) confirms the overall net benefit of retaining Mayo A powerhouse capabilities for the next 75 years versus the option of measures solely to retain ongoing Mayo B operation without Mayo A rockslide stabilization and remediation.[15]

Based on the above, it is therefore prudent that Yukon Energy design and implement a replacement for the surge chamber as soon as possible to provide protection for operations of the overall Mayo Generating Station facility.

Surge Chamber Options Assessment

A like for like replacement of the surge chamber with consideration for any future changes in flow was selected as:

- Re-locating the surge chamber would have required a substantial amount of tunnelling and blasting; and
- Replacing the surge chamber 'like for like' reduced the required outages and allowed a plug solution to be used for construction isolation.

Manufacturing a plug for the surge chamber allows the surge chamber to be replaced while the joint penstocks are still 'watered up' and Mayo B is still generating.

[14] Yukon Energy is required to pass water through the Wareham Dam Structure or the Mayo A plant to meet water licence requirements and ensure that the upper portion of the river has fish flows. The Wareham Dam is not currently able to pass flows during the winter, so flows during winter must be passed through the Mayo A plant. Spray from the spillway can freeze during winter operation, with ice buildup potentially becoming heavy enough to cause the spillway structure and access bridge to fail. Yukon Energy has recently received a winter spill pipe that can be installed in the event of an emergency and will allow Yukon Energy to pass water over the spillway in the winter.

[15] In order to retain Mayo B operation without MHO rockslide stabilization and remediation, it would be necessary to move or otherwise protect the substation facilities from rockslide instabilities, decommission MH0, and plug the MH0 penstock upstream of the surge chamber (with separate measures to enable winter flows in the upper portion of the Mayo River downstream of the Wareham Dam). Yukon Energy has recently received a winter spill pipe that can be installed in the event of an emergency and will allow Yukon Energy to pass water over the spillway in the winter. This was constructed for temporary use; a permanent winter spill solution would have to be investigated if the MH0 plant was abandoned.

- The surge chamber plug will isolate the surge chamber. This will allow the surge chamber to be removed and replaced in the dry, ensuring constructability, safety and allowing the penstocks to remain full. This will allow Mayo B to continue to operate while the surge chamber is replaced.

- A few options were considered for the penstock plug:

  - Pneumatic (inflatable), this type of plug couldn't be securely anchored, and these plugs are not proven for the types of pressures that are expected. It was uncertain if this type of plug could receive the Single Device Isolation Certification (SDIC) that would be required for construction.

  - A mechanical plug was selected as it was more widely available and a more proven technology in similar applications. The mechanical plug was the only option that met the SDIC requirements and could be temporarily installed.

The selected option was tendered with the Rockslide Stabilization and Remediation work in 2024. Three bids were received. The tender submission review is ongoing.

Surge Chamber Replacement Project Expected Capital Costs and In-Service Date

Table 5.1A-20 below provides details on the Surge Chamber Replacement Project expected capital cost of $27.831 million for planned in-service in 2026.

Table 5.1A-20: MH0 Surge Chamber Replacement Budget – Accounting for Tariff Risk

Items	2022-2024 ($000's)	2025 ($000's)	2026 ($000's)	Total ($000's)
Contractor			20,250	20,250
Consultant	448	130	275	823
YEC Internal Cost	110	20	105	236
Materials	623	1,200	300	2,123
Subtotal	**1,182**	**1,350**	**20,930**	**23,432**
AFUDC	29	24	358	411
Contingency		1,000	2,987	3,988
Total	**1,211**	**2,624**	**23,995**	**27,831**

Award of construction for the project is expected in April 2025. Construction is to be completed in 2025 and 2026 construction seasons. Project in-service is expected in fall 2026, following completion of construction.

All the construction work is planned to occur on Yukon Energy property and out of the water. No permitting is required for this work. The contractor will be responsible for complying with all applicable Territorial and Federal regulations, including tree clearing regulations.

5.1A-6: TRANSMISSION LINE REFURBISHMENT L178

Table 5.1A-21: Transmission Line Refurbishment L178 Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$932,000	$2,400,000	$1,584,000	$1,584,000	$6,500,000

Project Description

This project is a continuation of the project previously reported in both Yukon Energy's 2021 General Rate Application and Yukon Energy's 2023/24 General Rate Application. The project is expected to be completed in 2027.

The objective of the remaining project work is to refurbish the Carmacks to Faro (L178) transmission line like the other sections previously completed. Key structures, cross arms and insulators are being replaced as identified by the L178 specific Detailed Line Assessment performed in 2018 by Chimax Engineering (Chimax) and supported by studies completed by PowerTech in 2014 and 2015 on specific classes of insulators and cross-arms. By the end of the project, the following items will be replaced:

- All end-of-life insulators and cross-arms; and
- All components identified in the Detailed Line Assessment as being in poor condition and recommended for replacement within 5 years.

The Detailed Line Assessment completed in 2018 by Chimax established the scope of work for the multi-year refurbishment of L178. A portion of this work was completed between 2021 and 2024 while the remainder is planned for 2025-2027.

Project Justification

The 138 kV Whitehorse-Aishihik-Faro (WAF) transmission system which is a transmission 'backbone' was constructed in the late 1960's and early 1970's to serve the development of the Faro mine. The aging lines are reaching the end of their useful life. Prior to this project, maintenance on these lines was on a "spot repair" basis, under the annual Transmission Maintenance Program to repair broken or weakening structures and to perform maintenance as prioritized by test and treat inspections. It is essential to maintain the reliability of the system and therefore the recommended refurbishment needed to be completed.

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 grid to maintain supply to all customers.

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.

Based on the report from PowerTech in 2016, Yukon Energy operations replaced some insulators and high priority crossarms in conjunction with the replacement of transmission structures in the annual Transmission Maintenance Program. However, given the number of end-of-life insulators, cross-arms, and snowshed crossarms identified for replacement, it became clear that the work could not be completed within a reasonable timeframe under the annual Transmission Maintenance Program, which historically was only able to replace approximately 34 structures, with associated insulators and crossarms, per year. Therefore, a stand-alone capital project was required to complete the full scope of refurbishment work.

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.

Project Schedule and Budget

The cost for work completed through 2024 is $6.016 million. In the 2023/24 GRA, Yukon Energy showed 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. As a result, the amount previously approved and included in rate base through 2024 is $11.084 million. Yukon Energy indicated in the 2023/24 GRA the forecast to complete the project beyond 2024 was $8.55 million, resulting in a total forecast project cost of $19.63 million.

The reason for the variance between 2024 actual to 2024 approved is due to a change in plans and limited spending in 2024. In 2024, Yukon Energy's initial plan was to newly construct or substantially upgrade 48 access trails connecting the Campbell Highway to the transmission line right-of-way. These trails were originally expected to be upgraded to engineered highway standards as required by Highways and Public Works (HPW). However, after further analysis, Yukon Energy proposed a more cost-effective and sustainable approach to HPW: maintaining and clearing the 131 existing access trails in the L178 section (Carmacks to Faro) wherever possible.

This revised strategy avoids new construction, aligns better with First Nations perspectives, reduces the likelihood of increased public access to unsafe terrain and critical wildlife habitats, and is significantly more economical. HPW ultimately agreed with this approach, approving clearing, brushing, and ongoing maintenance of the existing trails. Permitting is now underway, including First Nation consultations, and the YESAB proposal is currently in the adequacy review stage. This strategic shift explains the limited construction activity in 2024.

Condition assessments were performed in 2018, 2021, and most recently during the "test and treat" program in 2024. In early 2025, Chimax, in collaboration with the T&D group, was finalizing the schedule and quantities for project spending and completion, looking at the option of completion by 2027 or deferring spending to have less of an impact on financing requirements in the test years. As reviewed below, under either scenario, as a result of the revised strategy the total project costs over the life of the project is now forecast at $16.366 million as compared to the previous estimate in the 2023/24 GRA of $19.63 million, a savings of $3.264 million.

The forecasts if the project was to be completed in 2027 are as follows:

Table 5.1A-22: Forecast Costs for Completion of Project in 2027

Work Description	Updated Assessment- 2024	Completed through 2024	Planned 2025-2027
Full Structure replacement	164	52	112
Cross Arm replacement	102	38	64
Insulator replacement	549	162	387
Total Structures replacement	815	252	563
No maintenance required	19		
Total Structures	**834**		

The project budget for the 2025, 2026 and 2027 test years totals $10.350 million if the project was to be completed in 2027 (see Table 5.1A-23 below).

Table 5.1A-23: Project Costs for 2025-27 Test Years (assuming 2027 Completion)

Item	2025	2026	2027
Yukon Energy Internal Cost	$192,000	$332,000	$304,000
Consultant	$75,000	$50,000	$50,000
Contractor and Material	$2,013,000	$3,560,500	$3,256,000
AFUDC	$0	$0	$0
Contingency	$120,000	$207,500	$190,000
Total	**$2,400,000**	**$4,150,000**	**$3,800,000**

If the project is decelerated and is not fully completed by 2027, the project budget for the 2025, 2026 and 2027 test years totals $5.568 million, with an expected $4.782 million to be completed after 2027, for a total post 2024 cost of $10.350 million (see Table 5.1A-24 below).

Table 5.1A-24: Project Costs for 2025-27 Test Years (assuming Post-2027 Completion)

Item	2025	2026	2027	After 2027
Yukon Energy Internal Cost	$192,000	$127,000	$127,000	$383,000
Consultant	$75,000	$20,000	$20,000	$60,000
Contractor and Material	$2,013,000	$1,358,000	$1,358,000	$4,100,000
AFUDC	$0	$0	$0	$0
Contingency	$120,000	$79,000	$79,000	$239,000
Total	**$2,400,000**	**$1,584,000**	**$1,584,000**	**$4,782,000**

Under either scenario, these costs would be added to ratebase as the work is completed, reflecting the fact that each refurbishment becomes used and useful upon its completion.

Due to financing constraints at the time of GRA submission, Yukon Energy has opted for the decelerated plan. This option continues to address accelerated refurbishment compared to the annual Transmission Maintenance Program.

In accordance with Yukon Energy's amortization policy for transmission poles and fixtures, these project costs will be amortized over 65 years commencing after completion of each structure.

5.1A-7: DAWSON VOLTAGE CONVERSION

Table 5.1A-25: Dawson Voltage Conversion Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$4,782,700	$1,010,000	$0	$0	$5,792,700

Project Description

The objective of the complete Dawson City Voltage Conversion project was to upgrade the Dawson distribution system to improve reliability, stability, and ensure appropriate capacity for a 25-year lifespan. It will include upgrades required to support the voltage conversion, as well as anticipated load growth and increased electrification.

According to the Yukon Energy appointed engineering consultant who performed an assessment on the Dawson distribution system in 2018, 4.16 kV systems are best suited to urban residential distribution with limited electrical heat and shorter feeder lengths. Dawson City's residential population, housing density, and commercial development have grown rapidly in recent years, exceeding the practical operating limits of the 4.16 kV system. Customers report that fluorescent lights flicker, and LED lights turn off prior to a power outage. These brownouts have been increasing in frequency according to information collected by the consultant and are a symptom of a system reaching its operating limit. The consultant's report recommended increasing the distribution system voltage from 4.16 kV to 12.5 kV.

Teshmont Consultants LP (Teshmont) 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 Yukon Energy'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.

- Poor voltage at the end of each feeder limiting secondary conductor lengths and forcing underutilization of the transformer capacity.

Project Status

The Dawson Voltage Conversion project was approved in the 2023/24 GRA, with forecast costs of $1.872 million added to approved rate base in 2024. The solution to be implemented was for a voltage conversion to 12.5 kV to relieve the load on the Dawson Dome area.

A thorough review of the project scope and existing site conditions in early 2024 resulted in refinements to the scope and the inclusion of a system rebuild. The additional work focused on replacing old poles and raising lines to provide adequate clearances. The estimate for the budget was refined and Yukon Energy Board approved an adjusted budget of 5,870,000 over two years.

The increased cost resulted from an increased scope of work. This also extended the project by a year. The adjusted scope included completing the re-build and all preparation work for the voltage conversion. It included increased engineering work, creation of design drawings, staking list, bill of materials, and an updated construction plan. The project preparation works included activities such as tree trimming and brushing, outage scheduling, setting new poles, replacement of distribution transformers, salvaging old units, primary and secondary conductor transfers, and re-insulating. In 2024, the top portion of these replacement poles were removed to allow NorthWestel to transfer their equipment/cable to the new poles which will happen during 2025.

Actual 2024 outcomes resulted in $4.783 million being included in WIP at year end and no addition to actual rate base.

The plan for 2025 is to complete the voltage conversion from 4.16 kV to 12.5 kV and the total completion of the project. The 2025 scope includes sectionalizing by installing openers, gang switches, inline switches, salvage old poles, re-sags, general mopping up, protection and control settings. In addition, NWTEL will complete transferring all their equipment/cables to the new poles. Once the transfer is complete, Yukon Energy will remove the remaining portion of the old poles.

Project Justification

Operational concerns in Dawson, including frequent power outages, constant voltage flicker, and longer fault clearing times, prompted Yukon Energy to proceed with the project based on the engineering assessment of the Dawson distribution system.

Teshmont recommended converting the operating voltage of the Dawson City distribution system from 4.16 kV to 12.5 kV in a single stage, including the implementation of revised protection coordination, at a total cost of $833,000 (with a 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.

The selected approach will upgrade the Dawson distribution system to improve reliability, stability, and ensure appropriate capacity for a 25-year lifespan. It will include upgrades required to support the voltage conversion, as well as anticipated load growth and increased electrification. The population is expected to increase in the Dawson area, leading to increased housing demand and community infrastructure. Electrification and increased electrical vehicle uptake will also place additional demands on the electrical grid.

Not addressing the issue would result in reliability and safety concerns if protective devices fail to operate, damage to customer equipment, and potential for minor fines related to not meeting CEA voltage requirements.

Project Schedule and Budget

The project is now scheduled to be completed in 2025 with a forecast cost of $5.793 million proposed to be added to rate base. Full costs of the project, including the initial work done prior to 2025, are detailed in the table below. Total rate base impact of $5.793 million includes $4.792 million in 2024 WIP and $1.010 million added costs in 2025.

Table 5.1A-26: Dawson Voltage Conversion Project Cost Breakdown

Item	Cost
Yukon Energy Internal Cost	$0.605M
Consultant	$0.295M
Construction	$2.000M
Materials	$2.050M
AFUDC	$0.170M
Contingency	$0.673M
Total	**$5,793,000**

In accordance with Yukon Energy’s amortization policy for distribution system overhead conductors, these project costs will be amortized over 35 years commencing after completion of the project.

5.1A-8: TRANSMISSION LINE HAZARD TREE REDUCTION AND RIGHT-OF-WAY WIDENING PROGRAM

Table 5.1A-27: Transmission Line Hazard Tree Reduction and Right-of-Way Widening Program Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$949,900	$949,900	$949,900	$2,849,700

Project Description

This project aims to mitigate the risks associated with tree-caused outages on transmission lines. The objectives include reducing the occurrence of outages caused by hazard trees and danger trees falling on conductors or within flashover distance. The project is forecast to incur $949,900 costs each test year, which will be closed and added to rate base on an annual basis.

Yukon Energy enlisted ATCO Power (2010) Ltd. (ATCO) to prepare a 10-year vegetation management plan based on best practices to minimize unscheduled maintenance and effectively manage rights of way (ROWs) according to regulation (see Appendix 3.4). One of the most critical aspects of integrated vegetation management (IVM) is obtaining an accurate spatial inventory of vegetation along the entire ROW. To develop a program for Yukon Energy, ATCO undertook a ground-based spatial inventory patrol of the approximately 1,116 km ROW to understand the scope of mechanical vegetation management work that would be required in the next 10 years. The data gathered during the ground-based inventory patrol helps inform key decisions on the current and future state of Yukon Energy's vegetation management program. Using the data gathered from the inventory patrol, ATCO developed a 10-year plan for activities to manage grow-in and fall-in risks on Yukon Energy's entire transmission system, including short- and long-term forecasts for mechanical treatments and inventory capture planning costs.

The scope encompasses a combination of two methodologies to accomplish the above objectives.

- **Selective tree removal** – Where only a select number of hazard and danger trees are present, individual tree removal will take place. 1,366 trees have been identified on these three most critical transmissions lines.

- **Mechanical Widen** – This methodology will be used in areas where most, or all the trees, in a condensed area are, or will be, hazard or danger trees. This methodology will utilize heavy equipment to perform bulk tree removals.

Project Justification

Transmission lines are essential to the integrity and reliability of the Yukon power system. Hazard trees predisposed to falling onto conductors, and danger trees that are susceptible to causing outages during adverse weather events, pose significant risks to the electrical system's reliability and public safety, especially during periods of cold weather, when the power system requires all sources of capacity. Additionally, dense trees near powerlines increase the likelihood of significant damage during forest fire activity, and trees falling on energized lines can cause forest fires. Addressing these risks is imperative to minimize service disruptions, minimize restoration costs, and mitigating the risk of a severe unplanned outage event.

A strong vegetation management program pays dividends in the long term. From wildfire prevention to bolstering public and worker safety to strengthening system reliability and operational integrity, the benefits of vegetation management are numerous. A properly maintained right of way helps asset owners locate issues more easily from the air and improves access for pole replacements and general maintenance work and patrol activities.

Project Schedule and Budget

This project is considered urgent as reliability is a strategic priority of Yukon Energy. This project will mitigate the likelihood of a sever outage event being caused by a tree contacting a transmission line. Delaying mitigation efforts increases the likelihood of outages and associated public safety hazards. Addressing these risks promptly improves the resilience of the transmission system.

ATCO’s plan includes a 1-year schedule based on the actual vegetation inventory information obtained between July 2023 and September 2024.

The majority (92.1%) of the current ROW (O&M) work is the mow operation, which is not surprising, as this is consistent with most northern Canadian utility system ROWs. The next biggest component on ROW vegetation management is slash (7.8%). Slash is a much more labour-intensive treatment than mow, so it is only prescribed on sites where mowing is not possible due to factors such as steep slopes, too much rock, and wet ground. Lastly, the trim task comprises less that 0.1% of the ROW inventory. This is to be expected, as trim should not occur on a ROW unless very good growing seasons cause “cycle buster” sites, a landowner refuses complete removal of a site or funding levels and the VM program do not allow for proper risk-based management.

Most of the current off ROW (capital) work is made up of the mechanical widen task. This again is not surprising for a northern Canadian utility system ROW, as when the ROW is built and maintained, governments require permits for the removal of live trees that are classified as danger trees. Danger trees are defined as trees that are completely healthy but if they do come over in a storm or similar event, will fall within flashover distance of the powerline conductors. Because of the approval constraints on mechanical widen programs, it is logical to see over 3,800 danger trees identified in the inventory. This is natural in forested landscapes where mechanical widen programs have been absent. Lastly, just over 1,200 hazard trees were identified during this inventory capture. Hazard trees are defined as trees that are predisposed to fall within flashover distance of the conductor because they are dead, dying or have a significant lean. Hazard trees will likely fall onto the conductor or within flashover distance at some point if they are not removed.

During the initial inventory capture, ATCO identified several critical clearance sites. Critical clearance locations are defined as areas where the vegetation is 1 m or less from the conductor at the time of patrol. All critical sites identified during the initial inventory patrol were completed in 2023. All work planned for 2024 was executed using the workplans derived from the initial inventory capture, ensuring that starting in 2024, Yukon Energy's ROWs can be fully managed using a risk-based approach.

2025 Action Plan

Based on the vegetation inventory obtained, ATCO recommends that in 2025, the only capital maintenance program planned for off-ROW vegetation is to complete the mechanical widening on L171 and to start this program on L170. The table below outlines the expected mechanical widening program costs in 2025.

Table 5.1A-28: Expected Mechanical Widening Program Costs (2025)

Project – Line #	Hazard Tree - #of Trees	Hazard Tree ($)	Danger Tree - # of Trees	Danger Tree ($)	Mechanical Widen (m^2)	Mechanical Widen ($)
L171	0	0	0	0	240,372	841,302
L170	0	0	0	0	31,208	108,598
Total	**0**	**0**	**0**	**0**	**271,400**	**949,900**

2026 Action Plan

Based on the vegetation inventory obtained, ATCO recommends that in 2026, the only capital maintenance program planned is a portion of L170 to be mechanically widened. 5.1A-29 below, outlines the forecast capital costs for 2026.

Table 5.1A-29: Forecast Capital Costs for 2026

Project – Line #	Hazard Tree - #of Trees	Hazard Tree ($)	Danger Tree - # of Trees	Danger Tree ($)	Mechanical Widen (m^2)	Mechanical Widen ($)
L170	0	0	0	0	271,400	949,900
Total	**0**	**0**	**0**	**0**	**271,400**	**949,900**

2027 Action Plan

Based on the vegetation inventory obtained, ATCO recommends that in 2027, the only capital maintenance program planned is on another portion of L170 to be mechanically widened. The table below outlines the forecast capital costs for 2027.

Table 5.1A-30: Forecast Capital Costs for 2027

Project – Line #	Hazard Tree - #of Trees	Hazard Tree ($)	Danger Tree - # of Trees	Danger Tree ($)	Mechanical Widen (m^2)	Mechanical Widen ($)
L170	0	0	0	0	271,400	949,900
Total	**0**	**0**	**0**	**0**	**271,400**	**949,900**

These project costs will be amortized over 40 years commencing after completion of each section of line.

Why do this project this way?

This scope of this work has been identified by ATCO based on the FAC-003 transmission vegetation management standard.

ATCO incorporated considerations such as Yukon Energy's available budget and the desire to meet FAC-003 level standards, focus more on the reduction of wildfire risks and implement a risk-based vegetation management program across the entire system. ATCO then combined these considerations with criteria such as vegetation management patrol and mechanical treatment cycle requirements for each project line, the growth rate of tree species in the area, and potential access and resource constraints.

Yukon Energy's ROWs are to be fully managed using a risk-based approach.

Performing this work allows Yukon Energy to be in compliance with FAC-OO3 and address the off-ROW hazards that have been identified. The plan provided by the consultant is a 10-year plan that addresses all aspects of transmission line vegetation management. This will enhance short and long-term reliability and resilience of these transmission lines. Methods of removal will align with industry best practices.

5.1A-9: SPARE POWER TRANSFORMER PROGRAM

Table 5.1A-31: Spare Power Transformer Program Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$75,000	$275,000	$2,325,000	$2,675,000

Project Description

This project is for the procurement of critical spare transformers to ensure network spares are in stock in the event of transformer failure. The project proposes identification of, prioritization of, specification development, and procurement of power transformer spare equipment, including Power PT transformers for PT stepdown substations, and HV transformer bushings.

Yukon Energy operates 36 high voltage oil filled substation Power Transformers, which either function as a GSU (Generator Step Up) transformer or as a power transformer to transfer grid energy to the distribution system (up to 34.5kV). Installing redundant transformers to protect against failure is costly and not justifiable in all situations.

A common utility practice to manage the risk of a transformer failure is to maintain a stock of spare power transformers which can be installed in the case of an unrepairable failure. The best practice is to stock common standard sizes of transformer which can be deployed in various failure scenarios, thus minimizing the number of spares held in stock.

Another method of managing the risk is develop loop paths in the grid to enable routing of power flow around the failure. Yukon Energy's grid is largely radial, and in most cases has few or limited options for re-routing of power flow without additional development of transmission lines and distribution feeders, which are large, long-term projects. The size and configuration of the existing grid thus presents inherent limitations to reliability which are not easily changed. The purchase of spare power transformers is one step to reduce these risks.

A transformer failure would result in one of the following scenarios:

- Unable to connect hydro plant to the grid;
- Unable to connect distribution district to the grid;
- Unable to transfer load to, or from, transmission line; and

- Unable to connect thermal plant to the grid.

The lead time to procure a large oil filled power transformer is currently between 2-4 years. Thus, if a power transformer were to fail with no redundancy or spare unit available, Yukon Energy would face a lengthy outage and would likely need make up for the transformer with additional generation or thermal run.

If a spare unit is available, it would be possible to reduce the consequence of that outage to a matter of weeks or less. This is a significant reduction in the potential consequence of failure.

Although Yukon Energy tests power transformers regularly (annual oil test, 5 year maintenance test cycle), it is possible that even if a potential failure is detected during maintenance inspection and testing, it may not be possible to replace the transformer (if repair is not feasible) in a reasonable timeframe because of the long procurement lead times involved, risking a potential in-service failure rather than a more economical planned and scheduled replacement with lower impact to customers. Holding a fleet of spare transformers in stock allows Yukon Energy to plan a justified replacement based on actual condition of the transformer in a timeframe which reduces the risk of in-service failure.

Yukon Energy's practice is to replace transformers based on condition, so that the capital cost of replacement is justified by the known risk of poor condition of the power transformer. The other side of this practice is that in the fleet of aging transformers, some units are older and in poorer condition than others and present a higher risk of failure. Even newer transformers are not immune to internal failures. Although a capital replacement may be planned, because of the long lead times involved, there is the risk of premature in-service failure before replacement can occur. This risk can be managed through holding a stock of spare power transformers.

The scope of this project is to determine an appropriate set of transformers of standard size which best meets Yukon Energy's need for spare units, balancing quantity and cost with flexibility of application. The project includes developing procurement specifications and technical requirements for those transformers, and the purchase of the required number of transformers.

Project Justification

This project is required for several reasons:

- Yukon Energy does not have spare transformer coverage for many power transformers in the system.

- Redundancy has not been built into Yukon Energy's power system. A power transformer failure would result in a long-term critical outage.

- As the load increases, the previous ability to re-route power is no longer available due to capacity limits.

- Lead times for power transformers are in the range of years; Yukon Energy cannot procure a transformer quickly after a failure.

- Having a spare on hand reduces the impact of failure for power transformers to a manageable level, but still not as well as planned, condition-based replacement.

- Condition of power transformers is monitored through testing and maintenance. If a pending failure is detected through condition monitoring and Yukon Energy has a spare on hand, Yukon Energy would be able to plan replacement of the failing transformer before an in-service failure occurs.

- Although Yukon Energy monitors condition of power transformers, failures do still occur under fault or unexpected operating conditions, and Yukon Energy has much aging equipment which is deteriorating but not yet justified for replacement.

Project Schedule and Budget

Yukon Energy is developing awareness of the risk involved in operating a radial grid power system without reddundancy. Insurance spares in the form of critical spare equipment mitigates the risk of failure and extended outage, although that risk mitigation comes at the cost of additional capital purchase and expense.

In summary, for reliability assurance, procurement of additional spare transformers is required. Once Yukon Energy has a list of spare transformers required, options can be considered for partnership with another utility (e.g. ATCO) to share capital spares, or how best to procure units. Based on current information, Yukon Energy expects that it will join the ATCO procurement process to take advantage of economies of scale. The asset management program is assisting Yukon Energy in being more aware of asset risk considerations.

The alternative to doing the project this way is to:

- Include purchase of critical spare parts as part of major capital projects to ensure that they are able to operate reliably in the case of unexpected failure. Example projects are 2003 Mayo-Dawson powerline and substation construction.

- Include redundancy in the design of the project. Examples include S176 Aishihik substation with dual, redundant power transformers in service.

In 2025, the work plan is to develop a list of spare transformers to procure which will:

- Align with future needs and growth plans (the transformers we need for the future);

- Identify common sizes and technical requirements;

- Develop a technical specification for transformer procurement; and

- Determine a viable method of procurement, whether through competitive bidding or through partnership.

2026 is for selection and award of contract for purchase of units.

2027 anticipates delivery of the first unit on an optimistic lead time of less than 2 years.

The project budget for the 2025, 2026 and 2027 GRA test years totals $2.675 million. These costs will be added to ratebase in 2027, reflecting the first year spare transformers are forecast to be purchased and on-hand.

Table 5.1A-32: Spare Power Transformer Program Costs Breakdown

Item	2025	2026	2027	Total
Yukon Energy Internal Cost	$25,000	$25,000	$0	$50,000
Consultant	50,000	0	0	50,000
Contractor	0	250,000	2,325,000	2,575,000
Total	**$75,000**	**$275,000**	**$2,325,000**	**$2,675,000**

The current forecast to complete the project beyond 2027 is $12.675 million, resulting in a total forecast project cost of $15.350 million. However, future costs (especially 2028 and on) are subject to more uncertainty and will be updated once these unknowns are clarified. Variables include the required number and size of spares, and unit pricing and lead times.

In accordance with Yukon Energy's amortization policy for critical spares, these project costs will be not be amortized until the spare goes into service.

5.1A-10: DAM SAFETY REVIEW MITIGATIONS

Table 5.1A-33: Dam Safety Review Mitigations Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$300,000	$1,200,000	$1,100,000	$2,600,000

Project Description

The purpose of this mitigation project is to address the deficiencies noted in the Dam Safety Reviews (DSR). Total forecast cost for the GRA test years is $2.6 million, with $0.3 million net rate base impact in 2025, $1.2 million net rate base impact in 2026, and $1.1 million net rate base impact in 2027.

A 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 Yukon Energy 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 addressed 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 Yukon Energy assets. This project was reviewed as part of the 2021 GRA.

Project Justification

Yukon Energy's water use licences require a full DSR to be performed every 5 years by an external consultant as recommended by the Canadian Dam Association (CDA). Reporting on mitigation action outcomes of this review is required by each Yukon Energy generating facility water use licence.

Project Schedule and Budget

The 2025 spending is to finish the last few mitigation projects from the 2020 DSR that require completion. The projects are all located within the WRGS facilities.

Mitigation projects for 2026 to 2029 shall be defined as per the Dam Safety Review to be completed in 2025. Higher spending is expected as the newly identified high priority items will be addressed first.

Table 5.1A-34: Dam Safety Review Mitigations Cost Breakdown

Item	2025	2026	2027
Yukon Energy Internal Cost	$75,000	$125,000	$125,000
Consultant & Contractor	$225,000	$1,075,000	$975,000
Total	**$300,000**	**$1,200,000**	**$1,100,000**

The project budget for the 2025, 2026 and 2027 test years totals $2.6 million. These costs will be added to ratebase as the work is completed, reflecting the fact that each sub-project becomes used and useful upon its completion.

In accordance with Yukon Energy's amortization policy, these project costs will be amortized over the number of years of the undetermined applicable asset class, commencing after completion of the project.

5.1A-11: WH3 HEADGATE REPLACEMENT

Table 5.1A-35: WH3 Headgate Replacement Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$85,500	$2,450,000	$0	$0	$2,535,500

Project Description

The project is to achieve the following outcomes for in service in 2025 at a forecast cost of approximately $2.535 million:

- Replace WH3 headgate and controls with a new headgate and controls that can be certified for single device isolation;
- Replace relay-based control system with a PLC control panel w/HMI;
- Refurbish headgate guides, embedded parts and hoist;
- Replace wire rope; and
- Integrate with WH3 unit protection, alarms and status (WH3 control cell /M3/ connects to SEL 2505 device at intake via fibre to transfer trips).

Specifications for replacement have been written by AtkinsRealis (formerly SNC Lavalin). The following is a high-level summary of the Contractor's scope of work:

- Supply and install of new WH3 headgate that is certified for single device isolation;
- Refurbishment of headgate embedded parts;
- Refurbishment of headgate hoist and replacement of hoist controls;
- As built drawings;
- Operation and Maintenance Manual;
- Spare parts for trouble free operation and maintenance for five years;

- Any special tools required to install, operate, maintain and repair the headgate and hoist;
- Inspection and test plans; and
- Commissioning report.

All deliverables must meet the specifications written by AtkinsRealis.

Project Justification

Yukon Energy's P125 Hydroelectric Generating Station (P125) consists of three generating units (WH1, WH2 and WH3) and was originally constructed in 1958. The intake structure consists of three separate intakes, each with a trashrack, stoplog slot and headgate. The three headgates are fixed-wheel vertical lift gates. WH3 headgate is the focus of this project. It was fabricated and installed in 1969.

It was determined back in 2010 that the WH0 headgates cannot be certified as is. Evaluations were done in the past to determine the best solution for certifying the headgates and replacement was the option chosen.

WH1 and WH2 headgates have been replaced and are now SDI certified. Yukon Energy plans to do the same with WH3 so the stoplogs no longer need to be used when underside work is completed on WH3. Using the stoplogs adds significant time and cost as the WH3 PMs are completed in the winter which requires steaming the stoplog guides and a mobile crane to install/remove the stoplogs. This will also give better control functionality and add additional protections to the headgate controls.

The current WH3 headgate is the original headgate from 1969. A structural inspection by SNC Lavalin in 2019 found that the gate needed repair or refurbishment to receive an SDI certificate. The SNC Lavalin assessment concluded that while the refurbishment estimate was 5% lower than the replacement cost, there was additional risk with refurbishment as only 25% of the gate was accessible for inspection. Therefore, it was determined to proceed with replacement rather than refurbishment. The replacement of the headgate will also provide a longer service life and reduce outage time of the WH3 plant. The gate also has been found to not fully close reliably when water is flowing through the unit.

Project Schedule and Budget

This project was scheduled to start in 2024 with a plan for construction in spring 2025. Based on the water levels in the reservoir upstream of P125 and winter conditions in Whitehorse the construction window has been identified as September to November 2025. Key milestones are as follows:

- RFP Closing: February 2025.
- Project Award: March 2025.
- Design: March to April 2025.
- Manufacturing and Delivery: April to August 2025.
- Site Construction and Commissioning: September to November 2025.

The following table shows major cost components for the project.

Table 5.1A-36: WH3 Headgate Replacement Cost Breakdown

Item	Cost
Yukon Energy Internal Cost	$160,000
Contractor	$2,200,000
AFUDC	$25,000
Contingency	$150,500
Total	**$2,535,500**

In accordance with Yukon Energy’s amortization policy for hydro structures and improvements, these project costs will be amortized over 72 years commencing after completion of the project.

5.1A-12: WH3 10-YEAR OVERHAUL

Table 5.1A-37: WH3 10-Year Overhaul Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$0	$50,000	$2,000,000	$2,050,000

Project Description

This project is to perform an overhaul on WH3. The scope of the WH3 10-year overhaul 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.

Project Schedule and Budget

All hydro units require a major overhaul after a certain number of years. The last overhaul for this unit was in 2013. To keep aligned with Yukon Energy past practice and industry standards the unit should be inspected and overhauled every ten years to maintain reliability. Looking ahead at future hydro overhaul planning, and trying to keep overhauls at one per year, 2027 was the first year available. Inspection, scoping and planning work will be done in 2026 with the overhaul performed in 2027. Yukon Energy's experience indicates that starting and completing an overhaul within one year has been too rushed, and having a year to inspect and plan an overhaul is much more manageable and better planned out. This is consistent with how Yukon Energy has performed recent hydro overhauls.

This work is required to ensure safe and reliable operation of the unit. Not performing a comprehensive major overhaul would raise the risk of an unplanned equipment failure beyond an acceptable level, with the consequence and downstream impact risks that include the following:

- In-service failure and additional collateral engine or facility damage;
- Poor reliability or not available to run when needed;
- Increased engine wear and more costly overhaul if performed later than scheduled; and

- Unplanned emergency callouts, unneeded overtime, and disruption to other planned work schedules.

The table that follows shows major cost components for the project.

Table 5.1A-38: WH3 10-Year Overhaul Costs Breakdown

Item	Cost
Yukon Energy Internal Cost	$150,000
Owner's Engineer	$100,000
Feasibility and Engineering	$100,000
Materials	$450,000
Construction	$1,100,000
AFUDC	$30,000
Contingency	$120,000
Total	**$2,050,000**

In accordance with Yukon Energy's amortization policy for hydro overhauls, these project costs will be amortized over ten years commencing after completion of the project.

APPENDIX 5.1B

CAPITAL PROJECTS >$400,000 AND UP TO $2 MILLION ADDED TO RATE BASE

APPENDIX 5.1B: CAPITAL PROJECTS >$400,000 AND UP TO $2 MILLION ADDED TO RATE BASE

5.1B-1: GENERATION PROJECTS

5.1B-1.1: Lewes River Boat Lock

Table 5.1B-1: Lewes River Boat Lock Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$1,440,100	$200,000	$0	$0	$1,640,100

Project Description

The Lewes River Boat Lock (the boat lock) is currently out of service until the gates can be replaced. Stage 1 project activities to date have provided a detailed review of options to repair the boat lock, and in 2025 a 30% construction package for the boat lock and road will be provided. Proceeding to Stage 2 with construction is deferred until resources and financing are available. While the project is a requirement by Transport Canada, no deadline or direction has been issued by Transport Canada.

Yukon Energy has deferred further work on this project to beyond the GRA test years. To avoid incurring significant AFUDC for several years, Yukon Energy considers Stage 1 of the project to be complete and is requesting that the Stage 1 project costs forecast to the end of 2025 be approved and added to rate base in 2025. As the project costs are over $1 million, Yukon Energy proposes amortization of the costs over a ten year period. Stage 2 construction of a new, fully operational boat lock will be undertaken as a separate project in the future with $0 starting work-in-progress costs.

Background

The boat lock was constructed in 1976 with the third (and current) Lewes River control structure. The boat lock serves the purpose of allowing small water-borne vessels to traverse the control structure for access along the Yukon River. On-going operation of the boat lock is a regulatory requirement under the Transport Canada *Navigable Waters Act* (the Act). The boat lock consists of a sheet pile channel with two sets of two manually operated gates.

The largest recorded flooding event along the Yukon River occurred in the summer of 2021. This caused many operational and logistical challenges in protecting the Lewes River control structure, including the boat lock. During the summer of 2021, the boat lock gates were welded in the open position to allow additional flow to help mitigate upstream flooding. The welds were broken, and the gates were damaged by high flows through the lock. The gates were removed to prevent further damage to the boat lock. Mega bags were placed around the boat lock to mitigate any potential erosion from the high-water levels. While flood waters overtopped the sheet piling of the boat lock, the mega bags were largely successful in preventing significant erosion.

After the flood levels receded in the fall of 2021, the boat lock gates were not re-installed due to their damaged state. When several of the flow control gates of the Lewes Control Structure were closed in the fall, a significant volume of water flowed through the open boat lock. Following this, serious erosion was identified on the downstream, shoreline end of the boat lock during a routine inspection in mid-October 2021. The shoreline quickly eroded and caused damage to the sheet piling of the boat lock. Temporary measures, including construction of a rip rap coffer dam and sluice gate, were quickly installed to prevent any further erosion. The boat lock is currently out of service until it can be replaced.

During the 2021 flooding event, the boat lock access road located on the upstream bank also experienced erosion and was taken out of service. Due to the level of erosion that occurred this road could not safely be reinstated. Following the flooding event, an existing trail high above the river, upstream of the lock, was upgraded for temporary access to the boat lock. This trail will need to be upgraded further to ensure future access to the boat lock and the right abutment of the Lewes Control Structure.

Project Justification

The project is necessary to maintain the functionality of the boat lock, which is a regulatory requirement of Transport Canada under the *Navigable Waters Act*. The Act defines navigable waters as “a body of water…, that is used or where there is a reasonable likelihood that it will be used by vessels”. The boat lock allows users to navigate the Yukon River from Schwatka Lake to Marsh Lake and beyond.

Project Schedule and Budget

Shoreline erosion of the area surrounding the boat lock was identified during a routine inspection on October 18, 2021. By October 20, 2021, the erosion had progressed further upstream, both on the eastern shoreline and within the sheet pile island. The mega bags had fallen in, and the sheet piles were severely damaged. Emergency measures were implemented in the fall of 2021 to prevent further erosion of the boat lock structures, and to temporarily secure the structure for the winter 2021/22. These temporary measures consisted of constructing a rip rap cofferdam upstream of the boat lock, installation of a sluice gate across the boat lock, and installing a rip rap cover on the eroded shoreline downstream of the lock.

The coffer dam and sluice gate are intended to slow the flows through the boat lock, while the downstream rip rap serves to stabilize the shoreline. These temporary repair works commenced on October 30, 2021, and were completed by November 24, 2021.

On February 9, 2022, the Yukon Energy Board of Directors approved proceeding with Stage 1 (the design phase, of the boat lock replacement).

Key projects activities completed in Q1 2022 following the project approval included:

- Issuance of the Request for Proposals (RFP) for the EPC contractor;
- Purchasing signage and buoys required under the *Navigable Waters Act*; and
- Communications to public about boat lock closure.

Only one RFP bid response was received, with a total bid price of $11 million. The bid was not technically strong, consequently, Yukon Energy did not recommend awarding the tender to the bidder. The recommended approach was to cancel the RFP and work with Stantec, the Owner's Engineer (OE), to develop a revised strategy for development of a design and pricing for the boat lock repair.

Two proposals were evaluated to determine the best value in determining the like-for-like replacement costs of the boat lock. One proposal was submitted from the OE (Stantec) describing the process of gathering all the information required to restore the boat lock back to its original condition (like-for-like replacement costs). This included a site inspection of the current conditions, an engineering review of the design drawings, and engaging with a 3rd party sheet piling company for a procurement and construction plan. The proposal also included utilizing a Remote Operated Vehicle (ROV) to collect 2D scans, pictures, and bathymetry data for the insurance claim.

An additional proposal was received from Ellis Don (not solicited by Yukon Energy). The insurance adjuster reached out to Ellis Don requesting that they submit a proposal for preparing a like-for-like replacement costs plan. Ellis Don submitted a like-for-like estimate without any cost to Yukon Energy. Therefore, the Ellis Don estimate was utilized for the like-for-like replacement costs. The estimate was approximately $10,500,000.

From an engineering perspective, Stantec was retained to prepare three different concept sketches to present to the public in Q4 2022. A public engagement was held in December 2022 to present the three concepts as prepared by Stantec. The following options were outlined:

1. Replace the existing boat lock with a like-for-like replacement;

2. Replace the existing boat lock in-kind; and remove the sheet pile island and replace it with two additional gates (to help mitigate flooding upstream in the Marsh Lake area); and

3. Excavate into the hillside, add several gates to the Lewes Control Structure and construct a new boat lock.

Key project activities in 2022 included installation of signage buoys as directed by Transport Canada under the *Navigable Waters Act*.

The project will generate public interest throughout the stages of planning and construction. Several public engagement meetings were held in Q1 2023 to gather input on the revised boat lock/control structure design. Public input was supportive in allowing for greater control over the flow of water through the addition of gates, as well as improving use and access when repairing the boat lock and selecting a cost-effective solution. Yukon Energy proceeded with investigating Option 2. A public RFP for a design engineer was issued in May 2023.

Three proponents submitted a proposal for the engineering phase of the boat lock project: BBA, AtkinsRealis, and WSP. AtkinsRealis was the successful proponent and scored the highest.

During the RFP process several gaps were identified.

- The first gap was the need to complete hydrotechnical analysis to confirm that the addition of two gates would have an impact on flood control, and that two gates was the appropriate number of gates.

- The other gap was an assessment of the remainder of the control structure's overall condition. The assessment of the overall condition of the structure was deemed to be important so the need for refurbishment or retrofitting work could be assessed, and if needed be, included in a construction contract for the boat lock replacement.

This additional scope was included in the project. In October 2023, the Engineering team updated the project's scope with support from the owner's engineer, and the budget was revised to include a more comprehensive examination of the structure to inform the tender process.

AtkinsRealis started the design phase of the project with a kick-off meeting in early October 2023 which included the Yukon Energy Civil Department and the OE (Stantec). Other work completed during 2023 included: site surveying, bathymetry, geotechnical investigation, and diving inspections. This provided the basis for the engineering design.

The primary activity during the first half of 2024 was the preliminary design of the access road and the engineering assessment of the flooding of the Yukon River to determine the impact on the structure and Marsh Lake. AtkinsRealis completed the hydraulic study to assess various boat lock configurations and Schwatka Lake levels on Marsh Lake flooding; the study examined the inclusion of two additional gates, the construction of a boat lock designed to convey flow, and the removal of an old dam sill, focusing on the 2021 flood event and a 1 in 100-year event in a future climate scenario. An assessment was submitted by AtkinsRealis that indicated that the two additional gates and flow conveyance through the lock would not provide a significant benefit to reducing the flooding on Marsh Lake, but these changes would come at an additional cost.

The Class 5 cost estimate for replacing the boat lock in kind is $11 million. Additional costs for structure or boat lock upgrades and road reconstruction are separate. Installing the additional gates is estimated at $3.38 million, with minimal annual power generation benefits of $116,000. Constructing the boat lock to convey flow is estimated at $500,000 and would come with additional operational maintenance requirements and risk. Given the negligible reduction in flooding relative to the significant cost, Atkins Realis and Stantec recommended proceeding with a scope that only includes the replacement of the boat lock. Yukon Energy decided to engage with the Yukon government representatives from Water Resources and Community Services to share study findings and receive comments prior to advancing detailed engineering.

The Yukon government Hydrologists reviewed the hydraulic study and were in general agreement with the study findings. In meetings with Yukon government to go over the removal of the two additional gates from the scope, Yukon Energy found that Yukon government was supportive.

The 2025 spending is for preparation of the 30% construction package for the boat lock and road. Progressing the boat lock to 30% design will allow it to be picked up quickly in the future and allows the possibility of design build in the future. The hydraulic, geotechnical and structural studies that have been prepared so far as part of this project will support the future design, as well as ongoing operations, water level management and other projects at the Lewes Control Structure.

The timing of Stage 2 of the project is highly dependent on guidance from Transport Canada.

The project budget for 2025 is $200,000. Total costs to date on this project are $1.440 million. The forecast to the end of 2025 is $1.640 million.

Table 5.1B-2: Lewes River Boat Lock Costs to Date and Forecast for 2025

Item	Cost
Yukon Energy Internal Cost	$160,000
Owner’s Engineer	$225,000
Permitting	$50,000
Engineering, Procurement and Construction Contractor	$1,185,000
AFUDC	$20,000
Contingency	$0
Total	**$1,640,000**

Why do this project this way?

Given the initial timeline, an EPC contract was originally explored as the plan for executing the project. However, due to the quality of the bid and some unknowns around the design, a design engineer was hired. This approach has allowed us to conduct more studies at the structure, and to fully understand the geotechnical, hydraulic and structural conditions at the site. These studies will inform the boat lock design as well as other Yukon Energy work and communications. Completing the design to 30% in Stage 1 ensures that options for the future of the project remain open for consideration.

Stage 2 of the project will consist of completing the design and constructing the boat lock and road. The timing of Stage 2 is flexible and can commence as funding becomes available and pending direction from Transport Canada. Once Stage 2 begins Yukon Energy can use the 30% design to either hire an EPC contractor or hire a designer to complete the design and a contractor to complete the construction.

Conclusion

Based on the high cost of the project and the risk ranking as compared to other high-cost projects, it was determined that Stage 2 of this project must be deferred until resources and financing are available. While the project is a requirement by Transport Canada, no specific deadline or direction has been issued. Yukon Energy has deferred further work on this project beyond the GRA test years. To avoid incurring significant AFUDC for several years, Yukon Energy considers Stage 1 of the project to be complete and is requesting the Stage 1 project costs forecast to the end of 2025 be approved and added to rate base in 2025. As the project costs are over $1 million, Yukon Energy proposes amortization of the costs over a ten year period.

Stage 2, construction of a new, fully operational boat lock will be a separate project in the future with $0 starting work-in-progress costs.

5.1B-1.2: Critical Spare Parts – Hydro Generation Units

Table 5.1B-3: Critical Spare Parts – Hydro Generation Units Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$650,000	$600,000	$400,000	$1,650,000

Project Description

This project is a multi-year program for the identification and purchase of critical spare parts required for reliable operation of Yukon Energy's Hydroelectric generators. The critical spare parts are parts that if they fail will cause a long and expensive generation outage. The likelihood of failure is managed through inspection and maintenance. However, the lead time for parts is such that an unplanned outage is expected to occur between initial failure detection and the delivery of parts on-demand.

The scope of this project is limited to the generator and turbine assembly, and does not include auxiliary of BOP systems such as governor, compressed air, protection and control, etc. To be defined a critical spare, the item must meet all the following criteria:

- The item is unique to the asset it supports (substitutes are not available and/or cannot be readily fabricated);
- The absence of this item would cause a significant loss of asset service;
- Can have a significant negative impact on safety, environment;
- Regulatory requirements;
- The item has a long lead time for procurement; and
- There is an expectation of use of the item for more than one period.

For this project, Yukon Energy will evaluate each hydro generating unit for critical spare parts as part of each 10-year unit overhaul in the years 2023 through 2029. The overhaul team will find and evaluate the existing critical spare parts already owned for each unit as part of the overhaul project and determine if any additions are required to the list considering overhaul findings and failure history. The spare parts purchase recommendation for AH1 and AH2 was developed in this way and is the basis for the first procurement of critical spare parts in 2025.[1] At the end of each overhaul Yukon Energy will have a list of critical spare parts for each unit that are currently inventoried, a list of parts that should be purchased, and a justification for why those parts are needed.

Recommendations will be developed as follows:

- AH1&2 (overhaul 2022-2023; recommend required critical spare parts purchase for 2025);
- AH3 (overhaul 2024; recommend required critical spare parts purchase for 2026);
- MBH1&2 (overhaul 2025-2026; recommend required critical spare parts purchase for 2027);
- WH3 (overhaul 2027; recommend required critical spare parts purchase for 2028);
- WH1 (overhaul or uprate 2028; recommend required critical spare parts purchase for 2029);
- WH4 (overhaul 2029; recommend required critical spare parts purchase for 2030); and
- WH2 (overhaul 2030; recommend required critical spare parts purchase for 2031).

Why do this project now?

Stocking and ensuring availability of critical spare parts will reduce outage time if a critical part fails. Having a critical spare part on-hand also helps to de-risk the completion of major unit overhauls. For example, if upon disassembly of the unit it is discovered that a component replacement is required, but that the lead time is outside of the planned overhaul outage window, if a critical spare part is available in inventory, then the use of the critical spare part could allow the project to be completed as per its planned schedule. The stocked spare can then be replenished as the delivery schedule permits.

Why do this project this way?

It is an opportune time to assess existing critical spare parts stock and review the need for replacing or adding parts based on conceivable failures as the overhauls are performed.

[1] Due to procurement lead times, delivery of initial critical spare part not anticipated to be received by Yukon Energy until 2026, so a rate base addition does not occur until 2026.

5.1B-1.3: WHS West Gate Refurbishment

Table 5.1B-4: WHS West Gate Refurbishment Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$0	$200,000	$900,000	$1,100,000

Project Description

The project will refurbish the Whitehorse hydro plant west spillway gate.

Both Whitehorse hydro plant spillway gates have had issues with moving up and down and stalling; consequently, SCC has had issues controlling the gates. Having proper control of the gates is critical. Yukon Energy mechanics and electricians have done what they can to fix the gates while they are in service, but more significant refurbishment is required. There are numerous known issues with the gates that must be addressed. The spillway gates at the Whitehorse dam are critical infrastructure required to allow controlled spill of water and management of reservoir storage levels, as well as a safety feature to allow downstream flow which protects the dam from the risk of overtopping in flood years, or should generation at Whitehorse Rapids trip off in an outage.

The East Gate is being addressed first as it is having more problems. Repairs to the West Gate are expected to be similar in scope and process to the East gate.

The East Gate project started in 2024 by gathering background information on previous gate repairs, inspecting the gate while it is in-place, identifying issues with the gate from the operations department, and obtaining an owners engineer for the project.

Currently the gate has had operational issues and shows signs of deterioration, including the following:

- Gate jamming and not moving as required;
- Water leaking into the inside of the gate;
- Staunching rods require inspection;
- Rollers require inspection and suspect refurbishment work required;
- Reported signs of wear on gains; and

- Would like improved level sensors; previous ones were damaged by ice.

In 2025, it is expected that the Whitehorse Spillway Stoplog project will be completed. Once the spillway stop logs are returned to service, the spillway gates can be fully exercised and raised allowing for de-watered inspection of the gates and embedded parts.

The East Gate will be inspected in 2025, and a plan and estimate developed to complete the required corrective work. In 2026, the East Gate repairs are planned to be performed. The West Gate will also be raised and inspected in 2026, and a scope and plan for West Gate developed in the same year.

In 2027, the West Gate refurbishment is planned to be performed. The true cost will not be clear until the scope of work is defined based on the inspection. The 2027 costs are currently a budgetary placeholder.

Why do this project now?

It has been over ten years since the gates were last inspected and had maintenance work performed on them. If the work is deferred, there is a good chance that an emergency project will be required at additional expense and safety risk. Installing the stoplogs and working on a spillway gate is one of the more high-risk activities performed at Yukon Energy. To reduce safety risk it is best to plan this work ahead rather than wait for a failure to occur.

Fully exercising the spillway gates periodically for inspection and to ensure they operate as designed is a required component of the dam safety program and completing the inspections and repairs as planned and scheduled helps support compliance with dam safety regulatory activities.

Why do this project this way?

This project requires installing the stoplogs so the gate can be isolated from Schwatka Lake. A gate inspection will be performed first in 2026, then a repair plan developed, and the refurbishment work performed in 2027. Performing an inspection of the spillway gate first will allow for a better work plan to be developed and proper parts ordered ahead of time so the repair window with the gate out of service will be minimized. Doing only one gate at a time allows for the hydro plant to continue to be in-service while the other gate is not available.

5.1B-1.4: Whitehorse Spillway Stoplog Refurbishment

Table 5.1B-5: Whitehorse Spillway Stoplog Refurbishment Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$453,000	$1,499,000	$0	$0	$1,952,000

Project Description

The project will refurbish the Whitehorse hydro plant spillway stoplogs, which currently cannot be certified for maintenance on the spillway gate.

The Whitehorse Spillway stoplogs are used at the Whitehorse Dam to hold back Schwatka Lake upstream of the spillway gates so one gate at a time can be isolated for inspections, testing, maintenance and/or repairs. The stoplogs are the original stoplogs from 1958. The set consists of ten stoplogs that are installed in a specific stacking order upstream of the spillway gates. The stoplogs need to be certified and effectively seal to allow workers to work downstream of them on the spillway gates and spillway structure. The spillway gates need inspections and repairs as they have started showing reliability issues during operation. The stoplogs are installed using the dedicated WHS stoplog crane, which travels under a monorail beam that spans the two spillway bays and the stoplog storage area.

The Whitehorse Spillway Stoplogs currently do not seal properly and cannot be certified for single device isolation (SDI). Maintenance on the spillway gate is not possible without SDI certified stoplogs. It was recently discovered that the side guiding bumpers on the stoplogs have been cut off in the past and there is now too much play in the stoplogs side to side that they can easily be misaligned and the stoplog crane runs the risk of picking up a stoplog on only one side. These side bumpers need to be reinstalled. The project consists of the following:

- Replace existing timber seals on the stoplogs with rubber seals;
- Minor repairs and recoating the steel structure of the stoplogs; and
- Replace side guiding bumpers on stoplogs.

The 2023/24 GRA assumed $1.0 million of the Whitehorse Spillway Stoplog Refurbishment project was to be closed and included in rate base in 2024. As Yukon Energy did not complete the project by the end of 2024, it was not closed or added to rate base. The total $1.952 million cost is an increase of $0.952 million compared to the 2023/24 GRA amount.

The increase in project costs was primarily due to unforeseen conditions and additional work that was discovered:

1. **Unexpected Deterioration and Structural Issues**: After abrasive blasting and Non-Destructive Examination (NDE), extensive cracking in the welds of the stoplogs was identified. There were also concerns about steel delamination, which required additional testing and repairs. Furthermore, the ends of the stoplogs had previously been cut on-site using a torch, necessitating machining and build-up to restore proper dimensions.

2. **Deformation Requiring Machining**: Several stoplogs were found to be warped. This deformation required machining to create a level interface suitable for mounting the new rubber seals.

3. **Design Variation in Stoplog #10**: Stoplog #10 was discovered to be different in design compared to the others. This required a redesign and additional rework to accommodate the unique seal arrangement on this unit.

Why do this project now?

The following business advantages justify timely commencement of the WHS Stoplog Refurbishment project:

1. **Spillway gate inspection, testing, maintenance and repairs**

   The spillway gates are the original gates from 1958. They were last inspected in 2013and had minor repairs completed at that time. They are overdue for an inspection and have had reliability issues during operation over the past few months. There is limited ability to inspect, operate and test the gates without isolating them from Schwatka Lake with the stoplogs.

2. **Compliance with YEC's Whitehorse Dam Safety Program**

   Yukon Energy identified in the latest revision of the Whitehorse Dam Safety Program that the spillway gates should be fully exercised every five years. Before a gate can be fully exercised, the stoplogs need to be installed upstream. Completing this activity provides confirmation that the gates can fully operate if needed in an emergency. The Whitehorse Dam is in a very critical location, so Yukon Energy needs to have confidence that the gates will operate as needed. The gates are well overdue for this testing.

3. **Reliable installation of the stoplogs during the new stoplog crane commissioning**

   Without the side bumpers reinstalled, the stoplogs are more susceptible to jamming in the guides during installation or removal. Yukon Energy has had stoplogs jam in the past and this is a very expensive and high-risk situation to mitigate as divers are required to help unjam the stoplog. Jammed stoplogs also put extra stress on the entire spillway structure.

Why do this project this way?

The condition of the stoplogs was assessed by Klohn Crippen Berger (KCB) in 2021. The stoplogs require new seals, coating repairs and reinstallation of the side bumpers, which are missing. The stoplogs, themselves, passed their structural analysis modelling tests, so do not need to be replaced as the main structures are in acceptable condition.

5.1B-1.5: WHS East Gate Refurbishment

Table 5.1B-6: WHS East Gate Refurbishment Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$7,800	$200,000	$700,000	$0	$907,800

Project Description

The project will refurbish the Whitehorse hydro plant east spillway gate.

Both Whitehorse spillway gates have had issues with moving up and down as well as stalling; and SCC has consequently had issues controlling the gates. Having proper control of the gates is critical. Yukon Energy mechanics and electricians have done what they can to fix the gates while they are in service, but more significant refurbishment must be performed. There are numerous known issues with the gates that must be addressed. The East Gate is being addressed first as it is having more problems. The spillway gates at the Whitehorse dam are critical infrastructure required to allow controlled spill of water and management of reservoir storage levels. They are also a safety feature that allows downstream flow which protects the dam from the risk of overtopping in flood years or should generation at Whitehorse Rapids trip off in an outage.

The East Gate is being addressed first as it is having more problems. Repairs to the West gate are expected to be similar in scope and process to the East gate, however, each gate has a separate project submission.

The East Gate project started in 2024 by gathering background information on previous gate repairs, inspecting the gate while it is in-place, identifying issues with the gate from the operations department and obtaining an owners engineer for the project. The gate has had operational issues and shows signs of deterioration, including the following:

- Gate jamming and not moving as required;
- Water leaking into the inside of the gate;
- Staunching rods require inspection;
- Rollers require inspection and it is suspected that refurbishment work is required;
- Reported signs of wear on gains; and

- Would like improved level sensors; previous ones were damaged by ice.

In 2025, it is expected that the WH Spillway Stoplog project will be completed. Once the spillway stop logs are returned to service, the spillway gates can be fully exercised and raised allowing for de-watered inspection of the gates and embedded parts. The East Gate will be inspected in 2025, with a plan and estimate developed to complete the required corrective work. In 2026, the East Gate refurbishment is planned to be performed.

Why do this project now?

It has been over ten years since the gates were last inspected and had maintenance work performed on them. If the work is deferred, there is a good chance that an emergency project will be required at additional expense and safety risk. Installing the stoplogs and working on a spillway gate is one of the more high-risk activities performed at Yukon Energy. To reduce safety risk it is best to plan this work ahead rather than wait for a failure to occur.

The work to inspect the East Gate will be planned to follow the replacement of the Whitehorse Spillway Gate Stoplogs in 2025. The completion of the stoplog project in 2024 was delayed until 2025 because of difficulties in finding a qualified competitive bid proposal to produce this equipment. Once the new stoplog gates are available for use, they can be installed, and the East Gate can be fully exercised or an engineering inspection performed.

Fully exercising the spillway gates periodically for inspection, and to ensure they operate as designed, is a required component of the dam safety program. Completing the inspections and repairs as planned and scheduled helps support compliance with dam safety regulatory activities.

Why do this project this way?

This project requires installing the stoplogs so the gate can be isolated from Schwatka Lake. A gate inspection will be performed first in 2025, then a repair plan developed, and the refurbishment work performed in 2026. Performing an inspection of the spillway gate first will allow for a better work plan to be developed and proper parts ordered ahead of time so the repair window with the gate out of service will be minimized. Doing only one gate at a time allows for the ability to spill water if necessary to avoid the risk of overtopping the dam while the other gate is not available.

5.1B-1.6: Aishihik Canyon Control Structure Instrumentation, Control and Communications

Table 5.1B-7: Aishihik Canyon Control Structure Instrumentation, Control and Communications Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$150,000	$500,000	$0	$650,000

Project Description

This project will install fiber to the Aishihik Generating Station Canyon Control Structure and automate the valves to reduce in-person maintenance required and add continuous remote water level monitoring capability. This gives Yukon Energy the ability to remotely monitor and communicate with the control structure, to more accurately track reservoir water levels, and the ability to more closely control water spill into the Aishihik river drainage by remotely changing the valve settings to pass more (or less) water to better manage storage levels. The project also improves operator safety and efficiency, removing the requirement for an operator to travel solo to the Canyon Lake Control Structure to record lake levels, or to change valve settings during adverse weather conditions.

This project is already needed as an upgrade to water management. The reduction of possible flooding impacts elevates the importance of this project. Remote control of the Canyon Control Structure valves and fiber connection allows for quicker response and communications with the structure during flood events or high water. Flood events are forecasted to be very likely (4 out of 5) in 2023-2050. Flooding at Aishihik that could impact the Canyon Control Structure has been ranked in the severe category of all climate-related risks to Yukon Energy. In 2022, Yukon Energy saw water levels nearing the top of the Canyon Control Structure. If the structure was overtopped with significant amounts of water, damage could occur to the earthen parts of the dam, potentially washing away these areas, and making the dam itself more vulnerable. Automating valves gives Yukon Energy greater control and ability to react more quickly in times of high water. Quick response can reduce potential high-water impacts. There can also be impacts that could prevent staff from reaching the Canyon valves to set them, or where it is unsafe to access them preventing any adjustment to them.

Why do this project now?

High water events and flooding has occurred twice in recent years and is forecast to be very likely to occur from 2020-2050. Therefore, getting this automation and communication to the structure will give Yukon Energy the ability to monitor and react to higher water levels in the near term, reducing infrastructure and financial impacts of flooding, and to more closely control the management of the water levels in the reservoir to balance stakeholder needs and energy storage supply.

Why do this project this way?

Operations has identified that communication and automation of valves would reduce impacts of high water and reduce staff time and safety concerns.

5.1B-1.7: MBH0 Cooling Circuit

Table 5.1B-8: MBH0 Cooling Circuit Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$0	$60,000	$400,000	$460,000

Project Description

This project will provide an indoor radiator/cooling circuit for the Mayo B hydro plant to help lower plant temperatures.

The MBH0 plant experiences very hot indoor ambient operating temperatures through the summer months. Temperatures of +30°C to +40°C can be reached through many summer days. Ventilation fans have been installed but this system is not adequate to bring down the plant temperatures. Workers are at risk and must stay observant for signs of heat stroke while in the plant. An indoor radiator/cooling circuit would help lower plant temperatures.

Why do this project now?

This project will improve worker safety and the ability of Yukon Energy and contractors to complete planned maintenance and capital project work on schedule in the MBH0 plant. Some consequences of not correcting the problem are:

- Risk to worker health and safety;
- Potential work delays and additional maintenance or capital project cost in the summer months because people are unable to complete planned work as expected;
- Shortened life span of equipment due to operating outside of thermal limits. For example, station backup battery system's life expectancy goes down as the operating temperature goes up; and
- Potential impact on plant reliability. For example, electronic devices may overheat internally if ambient temperatures are too high.

Yukon Energy plans to correct the problem of the plant overheating before the problem causes additional reliability of cost issues.

Why do this project this way?

The first year of the project will result in detailed design allowing for construction in the second year.

5.1B-1.8: Aishihik Elevator Modernization

Table 5.1B-9: Aishihik Elevator Modernization Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$0	$0	$400,000	$400,000

Project Description

This project provides a complete modernization of the Aishihik Generating Station elevator.

The Aishihik elevator was originally manufactured and installed by Otis in 1974. A partial modernization was performed by Thyssen Krupp in 2000. An elevator condition and planning report was completed by Apex Elevator in September 2020. Part of the findings for future works (3-5 years) was a complete modernization (significant overhaul including replacement of the control system with necessary code retrofits associated with that of the elevator). The scope of work includes the following:

- Machine room equipment;
- Hoistway and top of car equipment;
- Hoistway door equipment;
- Cab interior;
- Pit equipment; and
- Elevator lobbies.

This elevator is required for staff to access the generating equipment in the plant, which is located 110 meters underground. If the elevator is not functioning or safe to operate, it would compromise Yukon Energy's ability to operate and maintain the plant and could delay or increase the cost of other planned capital improvements or operational requirements.

Why do this project now?

The external consultant report indicates there are significant deficiencies that need to be addressed. The timeframe is based on the elevator operation not deteriorating to a point where the work needs to be completed sooner.

Why do this project this way?

Performing a complete modernization rather than emergency fixes will result in a lower overall cost and allow for scheduled down times rather than uncontrollable and unexpected down time that could shut down hydro generation when it is needed most.

5.1B-2: TRANSMISSION PROJECTS

5.1B-2.1: Protection, Control and SCADA Upgrade: WH4

Table 5.1B-10: Protection, Control and SCADA Upgrade: WH4 Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$13,000	$450,000	$870,000	$0	$1,333,000

Project Description

The project will upgrade protection, control and SCADA at WH4.

Yukon Energy engaged SNC Lavalin in 2020 to complete a system wide assessment of its protection, control and SCADA assets as part of the Physical Asset Management Managed System (PAMMS) implementation. The assessment included site visit, data collection of assets, and evaluation of equipment asset health indices (AHI) based on age, obsolescence, physical condition and type. SNC has developed a 20-year asset management plan to replace protection and control assets in the Yukon Energy electrical grid.

The WH4 protection and control assets were installed in 2002 and are recommended to be upgraded before they start to fail. This upgrade will also include the addition of a unit programmable logic controller (PLC) for the full automation and monitoring of the hydroelectric generating unit.

The analog gauges and instrumentation at WH4 have been in service since 1983 and are at the end of life. Replacement parts are no longer available. Surface water, air cooler temperatures, flow, stator temperatures, creep detection and fire alarms are systems that can benefit from this upgrade. Digital monitoring will allow SCADA access and improved remote monitoring and control. The upgrade will reduce associated labour for manual meter reads and improve system reliability. The project will replace the WH4 governor control PLC cabinet which has been the cause of a number of WH4 trips.

Why do this project now?

WH4 hydro generating unit and plant is very critical to Yukon Energy's year-round operation so it would be beneficial to perform the upgrade before asset failure.

Why do this project this way?

This is consistent with Yukon Energy’s 20-year asset management plan for protection and control devices, as developed by SNC Lavalin in 2020.

The project will be executed over three years as follows:

- 2024: preliminary engineering and design; and
- 2025 & 2026: execution phase.

Atkins Realis has been selected as the owner's engineer per competitive tender and will be proceeding with the design basis memo and pre-engineering.

5.1B-2.2: Protection, Control and SCADA Upgrade: S150 Whitehorse Hydro

Table 5.1B-11: Protection, Control and SCADA Upgrade: S150 Whitehorse Hydro Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$0	$600,000	$700,000	$1,300,000

Project Description

The project will upgrade protection, control and SCADA at the Whitehorse Hydro substation (S150).

Yukon Energy engaged SNC Lavalin in 2020 to complete a system wide assessment of its protection, control and SCADA assets as part of the PAMMS implementation. The assessment included site visit, data collection of assets, and evaluation of equipment asset health indices (AHI) based on age, obsolescence, physical condition and type. SNC has developed a 20-year asset management plan to replace protection and control assets in the Yukon Energy electrical grid.

Yukon Energy prioritizes upgrade of protection and control electronic devices and protection schemes on a 20-year cycle on a basis of device obsolescence, typical reliable service life of electronic equipment, and a need to adapt protection and control equipment and schemes to an evolving operating, communication, and technology environment.

S150 is extremely critical to Yukon Energy's operations. Failure of protection and control equipment will affect customer reliability and safety. The S150 substation integrates energy output from WH0 and Whitehorse Diesel Generation (WD0 and Rental) and distributes that energy directly to AEY and transmission to the North. The protection and control equipment in S150 was installed in 2004 and includes feeder and transformer protection and control relays. This equipment is at the end of the typical useful life of 20 years. The protection and control equipment should be upgraded to modern equipment using up to date communications protocols and security tools.

The substation was identified for a replacement upgrade in 2017 and flagged as a priority station for upgrade in the 2020 protection and control assessment completed by SNC. This upgrade will ensure Yukon Energy continues to provide reliable service to its customers. New equipment offers better control, visibility, cybersecurity, reliability and communication interfaces with the equipment that Yukon Energy is using in the system.

Why do this project now?

Load growth in the Whitehorse area is increasing at a rapid rate and more control and visibility will help Yukon Energy better manage the increasing load. Protection mis-operation at S150 would result in widespread outages on the Yukon Energy grid, as well as potential damage to major critical equipment such as large power transformers.

Why do this project this way?

This is consistent with Yukon Energy's 20-year asset management plan for protection and control devices, as developed by SNC Lavalin in 2020.

5.1B-2.3: Transmission Line Test and Treat Program

Table 5.1B-12: Transmission Line Test and Treat Program Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$163,000	$300,000	$300,000	$200,000	$963,000

Project Description

This program serves the dual purpose of providing an objective measure of remaining pole life and slowing decay through re-treatment. The test and treat 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 experts in assessing the internal condition of wood poles and collecting required information for management of Yukon Energy's wood pole fleet. Test and treat is typically performed by a dedicated contractor specializing in this type of work.

The Transmission Line test and treat Program was previously approved in the 2023/24 GRA.

Why do this project now?

Condition information is required to properly plan structure replacements for Yukon Energy's transmission lines and to minimize risk of unplanned structural failure and resulting outage and restoration costs.

Why do this project this way?

The wood pole condition information collected through test and treat is used to plan and prioritize pole replacements over all of Yukon Energy's wood pole transmission lines. This quality of information is not available from detailed overhead line inspections.

Because the work is cyclical (planned test and treat cycle is 5 years), and requires a pesticide permit (for the retreatment), Yukon Energy prefers to outsource and competitively bid the pole test and treat program to skilled contractors who specialize in this work for the utility sector.

5.1B-2.4: T250-30 Silver King Transformer Replacement

Table 5.1B-13: T250-30 Silver King Transformer Replacement Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$80,000	$800,000	$0	$880,000

Project Description

The transformer at Silver King L250-T30 needs to be replaced as it is at end of life, in poor condition, and poses a risk to the environment. The load at this site is low. A smaller replacement may be appropriate depending on the load forecast from local customers; therefore, a review of loading is needed. Once the load forecast is determined, the project can proceed with procurement of the appropriate transformer and related materials.

Why do this project now?

The transformer at Silver King L250-T30 was installed in 1953 and is 72 years old. This unit is at end of life. Although the load at this site is low, if the transformer were to fail in-service the failure would result in a lengthy service outage to affected customers as no spare is available for this site, and engineering, design, procurement and construction lead times for an emergency replacement would be significant.

Why do this project this way?

An assessment prior to decision on size of transformer to be replaced is considered appropriate to ensure that the project is right sized to minimize costs.

5.1B-2.5: AH0 Switchgear and Breaker Replacement

Table 5.1B-14: AH0 Switchgear and Breaker Replacement Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$0	$100,000	$680,000	$780,000

Project Description

This project will replace the AH0 switchgear and breaker.

The AH0 generator floor switchgear is 1975 vintage, dating back to the original construction of the plant. The original breakers are FPE DST2-15-500 units. Generator field breakers are the same vintage and need to be included in the scope of work. These are smaller GE AFK 2C-1 units.

Switchgear and breakers fall under the capital asset class of Accessory Electric Equipment, with a life of 40 years. Therefore, the original equipment is fully depreciated. The switchgear condition is to be assessed in 2026. The condition assessment will validate the scope of the required work, resulting in a plan of action determined for replacement/upgrade/retrofit. The target replacement year is 2027.

When AH3 was added the redundant switchgear bay was pressed into service for the new unit, increasing the consequence of failure of the equipment. Each unit has one generator breaker, and if there is a breaker issue then that equipment is a critical point of failure. As Aishihik is the critical N-1 facility, it is essential to do this project.

Why do this project now?

The switchgear is past its expected end of life date. The project is required soon due to the risk associated with equipment failure. Equipment failure could take months to fix, resulting in loss of generation, potential energy shortfall, and high thermal generation costs. Because the switchgear is situated in the enclosed, underground powerhouse, there is potential additional safety risk to staff should there be a significant failure of the switchgear.

Why do this project this way?

The assessment will determine the value of life extension versus replacement and will improve the accuracy of the cost estimate based on those options. There is no alternative to proceeding with this work due to the risk of unplanned equipment failure.

5.1B-2.6: Transmission Structure Replacement Program

Table 5.1B-15: Transmission Structure Replacement Program Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$200,000	$300,000	$250,000	$750,000

Project Description

This project is to provide for long-term replacement of structures and poles in the transmission system. The estimated life of transmission structures and poles is 65 years. Based on pole demographics, the estimated number of annual structure replacements can be reasonably forecast. This project promotes working in a proactive manner and replacement based on condition. Reactive replacement after structure failure disrupts planned work and is more expensive than planned and scheduled work.

Yukon Energy's Transmission fleet includes approximately 10,000 wood poles. Of these poles, approximately one-third were installed between 1969 and 1976 for the Whitehorse-Aishihik-Faro grid and are now more than 50 years old. These lines are the current priority in Yukon Energy's Transmission Structure Program.

Why do this project now?

This project (Transmission Structure Replacement Program) is to commence in coordination with completion of the Transmission Line Refurbishment L178 project. It is expected that the L178 Refurbishment work will be completed in 2027 (or shortly thereafter with a decelerated plan) correcting deficiencies found during the Test and Treat inspection of L178 in 2024. As L178 work is completed, the cycle of inspection, and inspection based corrective structure replacement, will transition to the entire transmission system (69 kV and 138 kV towers and lines) rather than specifically L178. Once the refurbishment work on L178 is complete, the L178 refurbishment project will be closed, and the Transmission Structure Replacement Program will encompass the work program related to end-of-life structure replacements going forward.

The scope of work is intended to include end of life structure replacements but may include a lesser scope of work such as replacement of end-of-life critical structure components including cross-arms found to be in weakened, damaged, or poor condition or insulators at end of life. Hardware, hardware tightening, sway brace replacement and guy replacement are maintenance items completed under operations and maintenance expense funding.

For the years 2025-2027, the funding in the Transmission Structure Replacement Program is intended to address the replacement of structures found during planned test and treat inspection which are critical enough in condition due to structural defect that the structure requires immediate replacement to ensure safe and continued operation of the line. These structure replacements are termed 'emergent' replacements, and make allowance for that fact that although Yukon Energy endeavors to complete systematic planned and proactive replacement of condition based structures based on actual condition ascertained through field inspection, the field inspection work will inevitably find deteriorated structures or structure defects that require immediate correction for safety or structural reasons and cannot wait for a future year's work program. The funding for 2025-2027 is intended to address this reality.

Why do this project this way?

Yukon Energy has developed an Asset Management Plan for distribution poles. The Pole replacement program is based on actual condition of poles and relies on test and treat and inspection input to ensure structures are replaced at the appropriate time.

5.1B-2.7: Protection and Control Upgrade – S249 Breaking Resistor

Table 5.1B-16: Protection and Control Upgrade – S249 Breaking Resistor Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$0	$450,000	$0	$450,000

Project Description

The upgrades required to bring the outdated S249 breaking resistor protection and control equipment up to Yukon Energy protection and control standards requires the additional upgrade of the PLC automation equipment that controls the breaking resistors and includes the replacement of the existing electromechanical relays with microprocessor relays.

Why do this project now?

The importance of executing this project in the near term is criticality of the stability in the Mayo-Dawson area to adapt to the increased penetration of IPP solar and wind distributed energy resources currently online and to maintain stability with future IPP projects.

The original braking resistor protection and control equipment was installed in 2003 and is now 22 years old. Yukon Energy prioritizes upgrade of protection and control electronics on a 20-year cycle on a basis of device obsolescence, expected reliable service life of electronic equipment, and a need to adapt protection and control equipment and schemes to an evolving operating and technology environment.

Why do this project this way?

The frequency control and stability of the Mayo-Dawson area cannot be fully realized if this upgrade is not completed.

5.1B-3: DISTRIBUTION PROJECTS

5.1B-3.1: Customer Extensions (net of Customer Contributions)

Table 5.1B-17: Customer Extensions Costs Added to Rate Base (net of contributions)[2]

Opening WIP	2025	2026	2027	Total Additions
$0	$200,000	$200,000	$200,000	$600,000

Project Description

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 due to the inability to predict specific future requests. The annual net forecast cost of $200,000 (cost of $600,000, contributions of $400,000) has been in place since 2021.

Why do this project now?

Customer connection requests are received on an on-going basis.

Why do this project this way?

Most costs of customer extensions are covered by customer contributions pursuant to the Terms and Conditions of Service.

[2] Customer Extensions are shown in Appendix 5.1B as net of contributions, whereas Customer Extensions are shown gross in Tab 5, with contributions reported separately.

5.1B-3.2: Distribution Pole and Transformer Replacement Program

Table 5.1B-18: Distribution Pole and Transformer Replacement Program Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$350,000	$350,000	$350,000	$1,050,000

Project Description

This project is to provide for long-term end of life replacement of poles and transformers in the distribution system. Yukon Energy has approximately 5,000 poles in-service. The estimated life of distribution poles and transformers is 35-40 years as per Yukon Energy's depreciation study and per the Metsco draft Asset Management Plan developed for distribution poles. Based on this, on average, approximately 125 poles would need to be replaced each year. A large proportion of these distribution poles were installed in the 1970's, and roughly 40% of YEC's distribution poles will be greater than 45 years of age within the next 5 years. A conservative estimate of $350,000 annually has been established until condition data is available to refine the annual work plan costs. This provides for replacement of approximately 70 poles annually, at an average budgetary cost of $5,000 per structure.

Why do this project now?

Pole replacements are forecast based on age and expected end of life, but individual replacements are identified based on inspection and actual condition, or failure in the field.

Why do this project this way?

Yukon Energy has developed an Asset Management Plan for distribution poles. The forecast work levels are based on pole age; however, annual Pole replacement budgets and work programs are based on actual condition of poles and rely on test and treat and inspection input to ensure poles are proactively replaced when their condition indicates they are at end of life. Until test and treat pole internal condition data is collected, annual pole replacements are identified by field workers as externally damaged or leaning poles, severe woodpecker or ant damage, visible evidence of decay, or otherwise in obvious need of replacement. Similarly, leaking, burned, or failed-in-service distribution transformers are replaced out of this program.

5.1B-3.3: Grid Modernization Program – Advanced Metering Infrastructure (AMI)

Table 5.1B-19: Grid Modernization Program – AMI Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$50,000	$375,000	$275,000	$700,000

Project Description

The Grid Modernization Strategy identifies advanced metering infrastructure (AMI) as a critical initial step to modernize the Yukon Integrated System. AMI is a two-way communication system to collect detailed metering information throughout a utility's service industry. AMI is automated and allows real time, on-demand interrogations with metering endpoints.

The global increase in the adoption of micro generation technologies like electric vehicles, battery storage, and solar generation will put pressure on Yukon Energy to effectively meet customer's increasingly complex energy management requirements. AMI will deliver real-time analytics supporting distributed energy resources (DERs), electric vehicles (EVs), and grid modernization.

Yukon Energy's goal is to install AMI for all of Yukon Energy's customer distribution systems by the year 2030. The scope of the project between 2025-2027 includes:

- Conducting an IT infrastructure gap analysis;
- Defining, designing, and implementing network requirements to integrate with AEY AMI IT infrastructure;
- Designing and implementing an AMI pilot in the community of Dawson City; and
- Assessing feasibility of full-scale AMI implementation in all Yukon Energy distribution communities.

The pilot is planned for 2027 with forecasted installations of approximately 1,600 AMI's in Dawson City.

The benefits of Yukon Energy implementing AMI are as follows:

- **Employee safety:** AMI meters improve employee safety by eliminating manual meter reading, and effectively eliminating employee exposure to extreme cold temperatures and other potentially dangerous conditions which may be experienced in order to complete meter reads each month.

- **Increase staff capacity:** AMI will eliminate the need for a truck roll to disconnect/reconnect or read meters. Yukon Energy's complement of 1 FTE is unable to manage reading the meters for all Yukon Energy customers throughout all times of the year, and we hire contractors to read our meters when the FTE is not available. With AMI, we will free up capacity in operations, customer service, and metering.

- **Operational effectiveness:** AMI meters allow for operational effectiveness and grid stability. AMI meters can record outage events as they would be able to electronically show in the AMI platform headend system (HES) all affected meters to pinpoint the location of the outage before there is any need for customers to call them in. This will make it much easier to diagnose unplanned outages, resource restoration efforts, and communicate with the public about outage events. AMI meters will also allow for real-time monitoring and automated reaction to changing grid conditions.

- **Data reliability:** AMI's automatically ping and record customer electricity usage each month and are much more reliable than Yukon Energy's existing meters. At temperatures below minus 35, the displays on the current meters can appear blank which leads to missed reads and estimated, rather than accurate, customer bills.

- **Leveraging Demand Side Management initiatives:** Demand Side Management is critical for maintaining grid reliability, and its effectiveness is significantly bolstered by the capabilities offered through AMI metering. AMI metering will transform our approach to energy management by converting easily accessible raw data into comprehensive insights. This advancement will significantly enhance our efficiency, reliability, and overall customer satisfaction. AMI will play a vital role in promoting responsible energy consumption habits among our customers. This initiative will facilitate the transition of our customers from being passive ratepayers to proactive supporters of the energy system.

- **Rate design opportunities:** AMI metering increases flexibility in Rate Design (Capacity Market and Variable Rate Design). There has been discussion within the Yukon recently about rate restructuring and provision for Time of Use rates. AMI's are an integral component of the solution as they provide metering data required to divide the usage down to whatever the required intervals would be.

Why do this project now?

Yukon Energy (and AEY) meter reads are still conducted manually which is labour intensive and leads to the following inefficiencies and costs:

- Estimated or incorrect bills (from inaccurate reads) which result in a large volume of work for both utility and customer service staff to address day-to-day billing inquiries and complaints, complete monthly reviews, and queues of customer accounts;

- Work for powerline technicians to address check-reads and regular on/off (disconnect/reconnects). Rolling a truck every time there is a need to visit a meter; and

- Additional costs to procure contractors to conduct regular remote readings and backfill existing staff when meter reader is unavailable or away.

The AMI solution will allow for flexibility to be leveraged by other ongoing initiatives that require data from many endpoints.

Why do this project this way?

AEY is now in its pilot stage of launching AMI Metering. Collaborating on this initiative allows us to leverage shared resources, knowledge, and infrastructure. Moving forward together will maximize operational efficiencies and provide customers with the benefits of enhanced service reliability and improved data accuracy. The implementation of AMI will yield real-time monitoring, better demand management, and streamlined billing processes.

Looking Forward

Without AMI metering, Yukon Energy will face limitations in advancing crucial technologies such as an outage management and a Distributed Energy Resource Management System (DERMS). The advanced metering infrastructure (AMI) technology being considered has been established for over 20 years and is essential for collecting the necessary data to implement Demand Side Management and Time of Use rates. Adopting AMI will optimize operations and position Yukon for future innovations in energy management.

5.1B-3.4: South Fox Lake PT Upgrade

Table 5.1B-20: South Fox Lake PT Upgrade Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$457,800	$0	$0	$0	$457,800

Project Description

The project provides a Power Transformer (PT) upgrade at South Fox Lake as required for new customer loads.

South Fox Lake has had new customer loads being added at a steady pace and is near its design capacity. Adding additional customers would put the PT transformer and associated equipment at risk of being overloaded. If this issue is not resolved, the addition of future customers and service upgrades for products such as electric heat and EV chargers would be constrained.

The construction of the site is nearly complete. However, the project will remain open until early 2025 as it was delayed due to long material lead times of metering equipment.

Why do this project now?

In early 2023, Yukon Energy observed a peak load of 85 kW on the 100 kVA system. Since then, a new Yukon government Heat Tape of 25 kW has been installed, as well as additional residential customers.

Why do this project this way?

The recommended solution is to choose a location with better access and build a new PT site with an increased capacity. Doing nothing leaves customers in the area at risk of a long-term outage.

5.1B-3.5: Distribution Upgrades Program

Table 5.1B-21: Distribution Upgrades Program Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$150,000	$150,000	$150,000	$450,000

Project Description

Distribution upgrades are undertaken to replace structures that do not meet current standards. If the primary (high voltage) element of a structure is required to be modified for an attachment or other change, Yukon Energy must ensure the full structure, including existing components, meets current Canadian Standards Association (CSA) Code (CSA C22.3 No.1:20 Overhead construction defining clearances, separations and material standards). The annual upgrades budget is required for distribution upgrades and improvements in all Yukon Energy distribution districts. These capital upgrades are driven by new customer projects.

Existing infrastructure may need to be upgraded to meet current design standards criteria (e.g., transformers may not be adequately sized to accommodate increasing load, and poles may not be adequately sized or classed, etc.). Distribution upgrades include, but are not limited to, power pole upgrades, transformers upgrades and service upgrades to accommodate new and existing customers located within distribution districts.

Why do this project now?

The capital upgrades budget allows Yukon Energy to upgrade its existing infrastructure on an "as required" basis, driven by new customer connects/extensions.

Why do this project this way?

Part of conducting field checks for new customer projects includes assessing existing Yukon Energy assets. These assessments can highlight the need to upgrade aging Yukon Energy infrastructure. Note that new customer connect projects are required to pay for the cost of their new service connection per the Terms and Conditions of Service. These upgrades do not supplement the cost of individual new customer connect projects, but support upstream improvements and modernization anciliary to the individual connect project.

5.1B-3.6: Mendenhall PT Upgrade

Table 5.1B-22: Mendenhall PT Upgrade Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$399,900	$0	$0	$0	$399,900

Project Description

The project expands the design capacity of the Mendenhall Subdivision. It includes construction of a new PT site and installation of an additional 167 kVA transformer.

Mendenhall Subdivision has had new customer loads being added at a steady pace and is near its design capacity. Adding additional customers would put the PT transformer and associated equipment at risk of being overloaded. If this issue is not resolved, the addition of future customers and service upgrades for products such as electric heat and EV chargers would be constrained.

The construction of the site is nearly complete. However, the project will remain open until early 2025 to fully complete.

Why do this project now?

Mendenhall is nearing the transformer capacity.

Why do this project this way?

An engineering study was performed to determine the best solution for an upgrade. Doing nothing leaves customers in the area at risk of a long-term outage.

5.1B-4: GENERAL PLANT AND EQUIPMENT PROJECTS

5.1B-4.1: Vehicle Purchases

Table 5.1B-23: Vehicle Purchases Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$675,000	$600,000	$600,000	$1,875,000

Project Description

Fleet vehicles are regularly replaced based on an annual analysis that considers vehicle age, gas or diesel, mileage, condition, and amount of maintenance costs. Yukon Energy's analysis is based on best practices of other Canadian utilities.

Why do this project now?

Based on the vehicle replacement policy, the table below outlines expected vehicle purchases by year:

Table 5.1B-24: Summary of Expected Vehicle Purchases by Year

Year	Department	Model	Purpose
2025	Electrical	1 Ton	Operations
2025	Plant Operators	¾ Ton Tommy Gate	Operations
2025	Mechanical	1 Ton	Operations
2025	Corporate	Sedan/SUV	Pool Vehicle

Year	Department	Model	Purpose
2026	Corporate	¾ Ton	Pool Vehicle
2026	Customer Service	½ Ton	Meter Reading
2026	Mechanical	1 Ton	Operations
2026	Mechanical	1 Ton	Operations
2026	Customer Connections	¾ Ton	Customer Connections

Year	Department	Model	Purpose
2027	Transmission & Distribution	1 Ton	Operations
2027	Electrical	1 Ton	Operations
2027	Transmission & Distribution	1 Ton	Operations
2027	Transmission & Distribution	1 Ton	Operations

Yukon Energy also intends to purchase three additional vehicles in 2025 for two new electrical positions and one new transmission and distribution position.

Why do this project this way?

- The replacement of vehicles based on age, mileage, condition and maintenance costs required for the following reasons: Older vehicles, and those with high mileage, are more likely to experience mechanical issues and breakdowns, which can lead to increased downtime and repair costs.

- Regularly assessing the condition of vehicles helps companies to identify vehicles that are no longer reliable or safe for use. This ensures that the fleet remains efficient and minimizes the risk of accidents.

- As vehicles age maintenance costs tend to rise. By replacing vehicles before these costs become prohibitive, companies can save money in the long run.

- Newer vehicles often come with improved fuel efficiency, better technology, and enhanced safety features, which can contribute to overall operational efficiency and lower operating costs.

5.1B-4.2: Building Condition Report Refurbishments

Table 5.1B-25: Building Condition Report Refurbishments Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$400,000	$400,000	$400,000	$1,200,000

Project Description

This project provides building refurbishments, as recommended by previous Building Condition Reports, that are to be completed before the next Building Condition Report expected in 2028.

Building Condition Reports were prepared for each building for the purpose of assessing building conditions and deficiencies and to provide priortized recommendations. The reports were prepared by Roth IAMS Ltd. in 2023 and 2024. Examples of project building refurbishments work to be performed between 2025 and 2027 include:

- Replacement of wood siding at Aishihik staff house;
- Replacement of metal roofing at Aishihik staff house;
- Replacement of exterior panel overhead doors at Dawson office;
- Replacement of split system air conditioning at Dawson office;
- Replacement of metal cladding at Faro office;
- Replacement of interior lighting at Faro office;
- Replacement of metal cladding at Whitehorse P127 hydro plant;
- Replacement of motor control centres at Whitehorse P127 hydro plant;
- Replacement of elevator at Whitehorse main office; and
- Replacement of fire alarm system at Whitehorse main office.

Why do this project now?

The costs represent projects identified in the Business Condition Reports that are to be completed prior to the next report expected in 2028. The Business Condition Reports were reviewed by Yukon Energy and certain replacements will be performed based on urgency and availability of resources. Without major preventative maintenance, building repair expense continues to increase with variances resulting from not having issues identified early.

Why do this project this way?

The ongoing purpose of Building Condition Reports is to move away from a crisis management model to a preventative maintenance schedule for all Yukon Energy owned buildings. The cost savings from crisis management (i.e., a furnace failing in the middle of the winter), compared to preventative maintenance (i.e., identifying life cost cycling of a furnace) can be significant. The architectural, mechanical and electrical conditions can be assessed by using an outsourced engineering firm.

5.1B-4.3: Crane Refurbishment Program

Table 5.1B-26: Crane Refurbishment Program Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$400,000	$450,000	$300,000	$1,150,000

Project Description

This program is focused on addressing identified deficiencies to ensure continued safe and reliable operation of cranes and hoists.

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).

Why do this project now?

The annual costs represent estimated work required resulting from the annual certification inspections. It is expected that current major crane refurbishments and maintenance in 2025 and 2026 will result in reduced annual deficiencies going forward. Ensuring cranes are in safe operating condition and completing the work required to maintain certification is a requirement for managing worker safety in the plant. In situations where a crane is a required element in maintenance or capital work, the ability to safely and efficiently use the crane when needed helps to support the on-time and on-budget completion of the work.

Why do this project this way?

The purpose of annual crane inspections is to highlight risks to proactively fix deficiencies before they result in a significant issue. A failure related to a crane can result in work delays or uncompleted work, additional outage, labour or contractor cost related to delays, direct damage to equipment or facilities, safety violations, injury or death. The cost savings from crisis management compared to preventative major crane maintenance can be significant. Due to a requirement for a specific and unique skillset, qualifications and knowledge, annual crane inspections are performed by an outsourced crane service provider. These crane inspectors are certified within the trade and able to perform the work, whereas Yukon Energy staff is not ticketed to do so.

5.1B-4.4: Fish Ladder TWG Recommendations Implementation

Table 5.1B-27: Fish Ladder TWG Recommendation Implementation Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$268,100	$275,000	$0	$0	$543,100

Project Description

In 2022 a multilateral technical working group (TWG) made up of KDFN, TKC, C/TFN and Yukon Energy hired a consultant to conduct an eco-hydraulic assessment of the WRGS Fish Ladder. The results of this assessment produced nine recommendations for improvements at the WRGS Fish Ladder. This project is intended to carry forward and implement several of the recommendations. The implementation of the recommendations will support the water use relicensing, and the acquisition of a new *Fisheries Act* Authorization for the WRGS.

Pursuant to the engineering and eco-hydraulic assessment completed for the WRGS Fish Ladder in 2023, progressive implementation of the nine recommendations was proposed. Recommendations 1, 3, 4, 5, 6, 8, & 9 will be completed first. Recommendations 2 and 7 require more time to conduct design and prepare for construction.

The proposed recommendations are as follows:

1. Implementation of an attraction flow improvement plan;

2. Refurbishment of fish ladder attraction flow infrastructure and construct fish screens to guide fish into the fish ladder;

3. Implementation of a process to minimize time the fish ladder gates are down and blocking salmon passage;

4. Implementation of a process to ensure WH4 tailrace fish screens are installed prior to, and throughout, the salmon run;

5. Implementation of a process to maximize the annual days the fish ladder is operational;

6. Creation of an Operations, Maintenance, and Surveillance manual to ensure the knowledge required to operate the fish ladder effectively is transmitted to new workers;

7. Complete a feasibility study on options to naturalize the fish ladder;

8. Implementation of a study to investigate salmon pre-spawn deaths; and

9. Implementation of a study to investigate stress on salmon passing through the fish ladder.

Why do this project now?

Yukon Energy is committed to enhancing the environmental sustainability of our hydro facilities. To protect local fish populations and preserve aquatic ecosystems, Yukon Energy is proactively making improvements, where appropriate.

Why do this project this way?

The design and installation of an aluminum screen is the most cost effective, timely solution based on how the hydro facilities were established.

5.1B-4.5: SCADA Upgrade Program

Table 5.1B-28: SCADA Upgrade Program Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$10,000	$10,000	$510,000	$530,000

Project Description

The SCADA (Supervisory Control and Data Acquisition) upgrade program involves updating and enhancing the SCADA system used to monitor and control remote plants and substations from the System Control Center (SCC). Some key aspects of the SCADA upgrade program:

- **Modernization:** Upgrading outdated hardware and software to improve performance, reliability, and security;
- **Integration**: Ensuring compatibility with new technologies and systems, such as IoT devices and advanced analytics;
- **Cybersecurity**: Enhancing security measures to protect against cyber threats and vulnerabilities;
- **Scalability**: Expanding the system's capacity to handle more data and control more processes as the business grows; and
- **User Interface**: Improving the user interface for better usability and efficiency.

These annual upgrades help ensure that the SCADA system remains efficient, secure and capable of meeting the evolving needs of the industry.

Why do this project now?

The additional investment in 2027 is to build a SCADA datacenter to support grid modernization, and will consist of databases, a domain controller, logging tools and firewalls. These upgrades are also required to

- Better support customers and provide a more reliable service with implementation of an Outage Management System;
- Securely integrate home meters for demand side management; and

- Provide tools for secure vendor access to SCADA assets.

Why do this project this way?

The SCADA upgrade is required to deploy new technologies. Options will be evaluated to determine whether the solution will be built on-premises or through the cloud.

5.1B-4.6: Computer Replacements

Table 5.1B-29: Computer Replacements Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$160,000	$160,000	$160,000	$480,000

Project Description

The computer replacement program is a structured plan Yukon Energy uses to regularly update and replace computer hardware. All Yukon Energy employees require computers to some degree to perform their tasks and provide value. Computers that break down result in inefficiencies and cause lost productivity.

Why do this project now?

Based on the expected life of computer hardware, assets need to be refreshed every four or five years on a cyclical basis.

Why do this project this way?

The replacement of computers is essential for several reasons:

- Over time, computers can become slower and less efficient due to outdated hardware and software. Regularly replacing computers ensures that employees have access to the latest technology, which can enhance productivity and reduce downtime;
- Older computers may not support the latest security updates and patches, making them more vulnerable to cyber threats. A replacement program helps ensure that all devices are up to date with the latest security features, protecting sensitive company data;
- While it might seem cost-effective to keep using older computers, the maintenance and repair costs can add up. Newer computers typically require less maintenance and are more reliable, leading to lower overall costs. Outdated and failing computer hardware leads to productivity losses that can lead to significant downtime costs;
- As software and applications evolve, they often require more advanced hardware to run efficiently. A replacement program ensures that all computers are compatible with the latest software, preventing compatibility issues that can disrupt workflows;

- Providing employees with modern, efficient tools can boost morale and job satisfaction. It shows that the company values their work and is willing to invest in the tools they need to succeed; and

- Newer computers are often more energy-efficient, which can help reduce the company's carbon footprint. Additionally, many companies have programs in place to recycle old computers responsibly.

5.1B-4.7: Central Storeroom for Generation Parts

Table 5.1B-30: Central Storeroom for General Parts Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$200,000	$200,000	$0	$400,000

Project Description

This project is for the setup of a secure central storeroom for receiving, storage and issuance of parts and consumables for generation, and stations for operations and maintenance.

Yukon Energy is investing in spare parts to support the reliability of plants and equipment. Critical parts are held to mitigate the risk related to parts unavailability or long lead times in the event of a failure, where equipment or component failure would cause customer outage or use of fossil fuel to offset the loss of hydro generation, or undue safety or environmental risk. Centralized secure parts management is a business enabler for desired process improvements in planning, scheduling and execution of planned work, efficient use of skilled resources, plant uptime and reliability, and accountability.

Why do this project now?

Safe, secure storage of costly spare parts for the Battery Energy Storage System and new generation projects will be needed as those projects come on-line, to ensure that if an investment is made into spare parts, those parts will be available for use and in good condition when needed.

Why do this project this way?

A central storeroom for generation parts at the WRGS location is considered the best option as it would be located near many generation assets and most of the operations and maintenance staff.

5.1B-5: OVERHAULS

5.1B-5.1: MBH1 Overhaul

Table 5.1B-31: MBH1 Overhaul Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$75,000	$1,525,000	$0	$1,600,000

Project Description

This project is an overhaul on Mayo B Hydro Unit 1 (MBH1). Inspection, scoping and planning work will be done in 2025 with the overhaul performed in 2026. The 2026 costs may need to be increased as the AH3 overhaul was over $2 million, and this unit may cost a similar amount to overhaul.

All hydro units require a major overhaul after a certain number of years. MBH1 is coming up on this time and has a number of reported issues from operations that would be addressed as part of the overhaul. Specific areas to address include unit creep and wicket gate alignment, complete vibration system, replace LPU system, inspect and refurbish bearings, address oil leaks from bearing housings, and replace worn brake pads.

The purpose of scheduled overhauls is to ensure safe and reliable operation of the equipment and avoid downtime due to unexpected breakdown. Yukon Energy would like to achieve the following through the overhaul:

- Disassembly, inspection and reassembly of the turbine and the generator.
- Assessment and documentation of the unit's condition, and address specific issues identified:
    - Performance and health metrics.
    - Shaft line: measurement of the air gap, turbine runner clearances, bearing clearances, shaft runout and level.
    - Turbine distributor assembly:
        - Fix wicket gates alignment which is causing creep.

        - Replace servomotor.
    - Turbine inlet valve: inspect, trouble shot and fix.
    - Turbine instrumentation: equip the unit with instrumentation to monitor flow through the unit.
    - Turbine access hatches: enlarge the size of the manholes to ease access during maintenance.
    - LPU: replace components with readily available components for ease of maintenance.
    - Troubleshoot and complete the vibration sensor architecture.
- Inspection, testing and troubleshooting of various mechanical and electrical auxiliary systems and instrumentation:
    - Inspection of various generator components.
    - Inspection of various turbine components.
    - Inspection and general maintenance of mechanical auxiliaries.
    - Electrical testing of various components.
- Replacement of all wear components.
- Cleaning of components.
- Refurbishment of turbine components and bearings.
- Inspect generator, turbine and mechanical auxiliary systems and repair as required.
- Conduct inspection and testing of selected electrical equipment and instrumentation.
- Identify and correcting “discovery work” as needed.

Why do this project now?

MBH1 was installed in 2011. It was recommended the first overhaul occur at 15 years. Looking ahead at future hydro overhaul planning, and trying to keep overhauls at one per year, the MBH units should be overhauled at this time. MBH2 was selected by the hydro mechanical operations group for overhaul in 2025. MBH1 is scheduled for 2026.

Not performing a comprehensive major overhaul would raise the risk of an unplanned equipment failure beyond an acceptable level. This work is required to ensure safe and reliable operation of the unit. The consequence and downstream impacts of delaying or not performing the overhaul include the following risks:

- In-service failure and additional collateral engine or facility damage;
- Poor reliability or the unit being not available to run when needed;
- Increased engine wear and more costly overhaul if performed later than scheduled; and
- Unplanned emergency callouts, unneeded overtime, and disruption to other planned work schedules.

Why do this project this way?

Having a year to inspect and plan an overhaul is more manageable and results in better planning outcomes. This is consistent with how Yukon Energy has performed recent hydro overhauls. Starting and completing an overhaul within one year has been too rushed.

5.1B-5.2: MBH2 Overhaul

Table 5.1B-32: MBH2 Overhaul Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$96,900	$1,500,000	$0	$0	$1,596,900

Project Description

This project is to perform an overhaul on Mayo B Hydro Unit #2 (MBH2). Inspection, scoping and planning work will be done in 2024 with the overhaul performed in 2025. The 2025 costs may need to be increased as the AH3 overhaul was over $2 million, and this unit may cost a similar amount to overhaul.

All hydro units require a major overhaul after a certain number of years. MBH2 is coming up on this time and has a number of reported issues from operations that would be addressed as part of the overhaul. Specific areas to address include unit creep and wicket gate alignment, complete vibration system, replace LPU system, inspect and refurbish bearings, address oil leaks from bearing housings, and replace worn brake pads.

The purpose of scheduled overhauls is to ensure safe and reliable operation of the equipment and avoid downtime due to unexpected breakdown. Yukon Energy would like to achieve the following through the overhaul:

- Disassembly, inspection and reassembly of the turbine and the generator.
- Assessment and documentation of the unit's condition, and address specific issues identified:
  - Performance and health metrics.
  - Shaft line: measurement of the air gap, turbine runner clearances, bearing clearances, shaft runout and level.
  - Turbine distributor assembly:
    - Fix wicket gates alignment which is causing creep.
    - Replace servomotor.
  - Turbine inlet valve: inspect, trouble shot and fix.

  - Turbine instrumentation: equip the unit with instrumentation to monitor flow through the unit.
  - Turbine access hatches: enlarge the size of the manholes to ease access during maintenance.
  - LPU: replace components with readily available components for ease of maintenance.
  - Troubleshoot and complete the vibration sensor architecture.
- Inspection, testing and troubleshooting of various mechanical and electrical auxiliary systems and instrumentation:
  - Inspection of various generator components.
  - Inspection of various turbine components.
  - Inspection and general maintenance of mechanical auxiliaries.
  - Electrical testing of various components.
- Replacement of all wear components.
- Cleaning of components.
- Refurbishment of turbine components and bearings.
- Inspect generator, turbine and mechanical auxiliary systems and repair as required.
- Conduct inspection and testing of selected electrical equipment and instrumentation.
- Identify and correcting "discovery work" as needed.

Why do this project now?

MBH2 was installed in 2011. It was recommended the first overhaul occur at 15 years. Looking ahead at future hydro overhaul planning, and trying to keep overhauls at one per year, the MBH units should be overhauled at this time. MBH2 was selected by the hydro mechanical operations group for overhaul first (in 2025) as the MBH2 wicket gate seals needed replacing as soon as possible.

Not performing a comprehensive major overhaul would raise the risk of an unplanned equipment failure beyond an acceptable level. This work is required to ensure safe and reliable operation of the unit. The consequence and downstream impacts of delaying or not performing the overhaul include the following risks:

- In-service failure and additional collateral engine or facility damage;
- Poor reliability or not available to run when needed;
- Increased engine wear and more costly overhaul if performed later than scheduled; and
- Unplanned emergency callouts, unneeded overtime, and disruption to other planned work schedules.

Why do this project this way?

Having a year to inspect and plan an overhaul is much more manageable and better planned out. This is consistent with how Yukon Energy has performed recent hydro overhauls. Starting and completing an overhaul within one year has been too rushed.

5.1B-5.3: WG1 30,000 Hour Overhaul

Table 5.1B-33: WG1 30,000 Hour Overhaul Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$1,520,000	$0	$0	$1,520,000

Project Description

The project provides 30,000-hour major overhaul for the WG1 unit at the Whitehorse LNG plant.

Scheduled runtime-based engine overhauls are capital renewal projects to perform an overhaul on a thermal generating engine to ensure that the engine can continue to operate reliably. Scheduled runtime-based engine overhauls are one part of the overall lifecycle strategy for thermal engines, which includes minor running maintenance, fluid analysis, planned maintenance, and detailed condition inspections.

Yukon Energy's three natural gas engines are maintained based on hourly run times according to the manufacturer's recommendation. Major inspections are scheduled every 10,000 operating hours (although inspections and condition monitoring may indicate that an overhaul is required earlier than expected), with varying procedures performed based on the total hours in the cycle. Not performing 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 of the unit.

The project is a renewal/replacement of the internal engine components, as recommended by the manufacturer. The purpose of scheduled overhauls is to ensure safe and reliable operation of the equipment and avoid downtime due to unexpected breakdown. Based on the total cycle hours of 30,000, the below additional major procedures of inspection and maintenance will be performed:

- Pre-combustion chamber/Pre-combustion chamber gas valve/Spark plug sleeve;
- Starter;
- Cylinder head replacement;
- Pre-lubrication pump;
- Crankshaft thrust bearing;

- Exhaust-gas turbocharger;
- Engine cooling water pump;
- Gas quantity controller;
- Pressure regulator for exhaust gas turbocharger lube oil supply;
- Piston/Piston cooling;
- Engine oil pump;
- Connecting rods and connecting rod bearings;
- Cylinder liner;
- Main crankshaft bearing/thrust bearing; and
- Camshaft/control system.

Why do this project now?

Unit WG1 is forecast to reach the 30,000-hour mark in 2025. As of December 23, 2024, the unit had approximately 25,700 hours. The consequence and downstream impacts of delaying or not performing the hours-based maintenance on the manufacturers recommended schedule include the following risks:

- In-service failure and additional collateral engine or facility damage;
- Poor reliability or not available to run when needed;
- Increased engine wear and more costly overhaul if performed later than scheduled; and
- Unplanned emergency callouts, unneeded overtime, and disruption to other planned work schedules.

Why do this project this way?

There is no alternative to proceeding with this work due to the risk of unplanned equipment failure. The options for this project relate to how to do the work. The project work (the overhaul) will be carried out by specialized contractors, and the contractors will be managed by Yukon Energy technical staff. Specialized contractors are necessary to perform the work because Yukon Energy’s maintenance workforce is limited, and due to the expertise required to perform maintenance on these units.

5.1B-5.4: WG3 30,000 Hour Overhaul

Table 5.1B-34: WG3 30,000 Hour Overhaul Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$0	$1,520,000	$0	$1,520,000

Project Description

This project provides the 30,000-hour overhaul for the WG3 unit at the Whitehorse LNG plant.

Scheduled runtime-based engine overhauls are capital renewal projects to perform an overhaul on a thermal generating engine to ensure that the engine can continue to operate reliably. Scheduled runtime-based engine overhauls are one part of the overall lifecycle strategy for thermal engines, which includes minor running maintenance, fluid analysis, planned maintenance, and detailed condition inspections.

Yukon Energy's three natural gas engines are maintained based on hourly run times according to the manufacturer's recommendation. Major inspections are scheduled every 10,000 operating hours (although inspections and condition monitoring may indicate that an overhaul is required earlier than expected), with varying procedures performed based on the total hours in the cycle. Not performing 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 of the unit.

The project is a renewal/replacement of the internal engine components as recommended by the manufacturer. The purpose of scheduled overhauls is to ensure safe and reliable operation of the equipment and avoid downtime due to unexpected breakdown. Based on the total cycle hours of 30,000, the below additional major procedures of inspection and maintenance will be performed:

- Pre-combustion chamber/Pre-combustion chamber gas valve/spark plug sleeve;
- Starter;
- Cylinder head replacement;
- Pre-lubrication pump;
- Crankshaft thrust bearing;

- Exhaust-gas turbocharger;
- Engine cooling water pump;
- Gas quantity controller;
- Pressure regulator for exhaust gas turbocharger lube oil supply;
- Piston/Piston cooling;
- Engine oil pump;
- Connecting rods and connecting rod bearings;
- Cylinder liner;
- Main crankshaft bearing/thrust bearing; and
- Camshaft/control system.

Why do this project now?

Unit WG3 is forecast to reach the 30,000-hour mark in 2026. As of December 23, 2024, the unit had approximately 23,200 hours. The consequence and downstream impacts of delaying or not performing the hours-based maintenance on the manufacturers recommended schedule include the following risks:

- In-service failure and additional collateral engine or facility damage;
- Poor reliability or not available to run when needed;
- Increased engine wear and more costly overhaul if performed later than scheduled; and
- Unplanned emergency callouts, unneeded overtime, and disruption to other planned work schedules.

Why do this project this way?

There is no alternative to proceeding with this work due to the risk of unplanned equipment failure. The options for this project related to how to do the work. The project work (the overhaul) will be carried out by specialized contractors, and the contractors will be managed by Yukon Energy technical staff. Specialized contractors are necessary to perform the work because Yukon Energy's maintenance workforce is limited, and due to the expertise required to perform maintenance on these units.

5.1B-5.5: DD4 Major Overhaul

Table 5.1B-35: DD4 Major Overhaul Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$975,000	$0	$0	$975,000

Project Description

This project provides major overhaul of the DD4 Dawson 1.4 MW diesel unit.

Scheduled runtime-based engine overhauls are capital renewal projects to perform an overhaul on a thermal generating engine to ensure that the engine can continue to operate reliably. Yukon Energy's diesel engines are maintained based on hourly run times. The purpose of scheduled overhauls is to ensure safe and reliable operation of the equipment and avoid downtime due to unexpected breakdown. Benefits of the project include:

- Overhauled engines will operate more efficiently, providing better power and fuel economy;
- Replacing worn components and addressing underlying issues will extend the lifespan of the engines;
- While the initial investment is significant, overhauling engines can save money in the long run by avoiding expensive repairs and premature replacements; and
- Overhauled engines are more reliable, reducing the risk of unexpected breakdowns and associated costs.

Why do this project now?

This project relates to completing a recommended 24,000-hour overhaul of the DD4 unit, as per the 2022 Collicutt inspection report. Not performing critical maintenance on the schedule recommended would raise the risk of an unplanned equipment failure beyond an acceptable level. This work is required to ensure safe and reliable operation of the unit. This project will help extend the life of DD4.

The condition inspection of the unit by the consultant, documented in the inspection report, indicates that the overhaul is required to ensure the engine can continue to operate reliably when needed, and to avoid more extensive in-service failure to the engine from the worn components.

Why do this project this way?

Scheduled runtime-based engine overhauls are one part of the overall lifecycle strategy for thermal engines, which includes minor running maintenance, fluid analysis, planned maintenance, and detailed condition inspections.

5.1B-5.6: WG0 10-Year Major Plant Overhaul

Table 5.1B-36: WG0 10-Year Major Plant Overhaul Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$60,200	$500,000	$0	$0	$560,200

Project Description

The project provides a 10-year major plant overhaul for the Whitehorse LNG facility.

Scheduled runtime-based engine overhauls are capital renewal projects to perform an overhaul on a thermal generating engine to ensure that the engine can continue to operate reliably. Similarly, plant maintenance is required on a regular basis to help maintain these facilities in good working condition, extending their lifespan and ensure they can deliver power when needed. Current less extensive maintenance tasks are based on daily, weekly, monthly, annual, biannualy or 5-year cycles, and are expensed as part of the O&M maintenance program.

In 2024, Yukon Energy worked with an owners engineer to develop a scope of work for life extension tasks to be performed on a 10-year cycle on the LNG facility (this project), to ensure that the plant remains in safe operating condition and complies with applicable safety codes. This scope of work includes:

- Recertification of pressure vessels and piping, weld inspection, and corrosion monitoring;
- Static devices (eg PRV’s, Heat Exchangers, Tanks);
- Circulation Heaters;
- Rotating Equipment (Pumps, Motors); and
- Electrical and Pneumatic actuators and valve.

The 10-Year Major Plant Service is a check-in above and beyond the normal maintenance schedule, and includes work not normally included on the regular cycle. Cost estimates are based on preliminary discussions with potential contractors.

Major overhauls are scheduled every 10 years (although inspections and condition monitoring may indicate that an overhaul is required earlier than expected). Not performing critical assessment and major maintenance would raise the risk of an unplanned equipment failure beyond an acceptable level. This work is required to ensure safe and reliable operation of the unit.

This project will look over all major mechanical equipment and safety equipment (PRVs, burst discs, fire water) and identify tasks for the 10-year outage in 2025. This project includes foundation repairs for the storage tanks. The project will identify the 10-year scope for each component as determined by regulations, OEM recommendations, applicable industry standards, or Yukon Energy observations and maintenance history.

Why do this project now?

The Whitehorse Gas Plant will be 10-years old in 2025.

Why do this project this way?

There is no alternative to proceeding with this work due to the risk of unplanned equipment failure. The options for this project are how to do the work. Currently there is no 10-year maintenance plan so the initial work during 2024 is to develop, review and finalize the major maintenance plan. In 2025, the project work (the overhaul) will be carried out by specialized contractors, and the contractors will be managed by Yukon Energy technical staff. Specialized contractors are necessary to perform the work because Yukon Energy’s maintenance workforce is limited, and due to the expertise required to perform maintenance on the plant.

5.1B-6: INTANGIBLE ASSETS

5.1B-6.1: Gates Certification Program

Table 5.1B-37: Gates Certification Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$177,800	$450,000	$300,000	$300,000	$1,227,800

Project Description

This intangible asset program is required to meet SDIC certification that is driven by Yukon Workers Safety and Compensation Board regulations for working in confined spaces.

The intent of the Single Device Isolation (SDI) inspection and certification program is to ensure that Yukon Energy's hydro intake gates, tailrace gates, spillway gates, bulkheads, stoplogs, Turbine Inlet Valve (TIV), and SDI hydro related points are certified as energy isolation devices in order to ensure that planned and emergency work on Yukon Energy's hydroelectric turbines and generators can proceed safely when needed, and that these devices will perform as required in all defined daily and emergency operating scenarios.

This program is taking place over multiple years. A consultant has been hired to inspect the majority of Yukon Energy devices that do not have current certification in the first two years (2024-2025). These inspections will result in either a certified device or a list of further inspections and fixes required before certification can be achieved. Yukon Energy relies on engineered SDI systems to isolate and dewater confined space work areas within hydro power facilities. The gate certification program is required to meet these regulations.

In 2025, the following devices will be inspected and reviewed:

- Mayo B TIVs and Tail Race Gate;
- Mayo lake valve chambers isolating gates; and
- AH0 pivot valve (intake) and bulkhead.

Why do this project now?

SDI recertification is required on a 5-year cycle in Canada for devices/systems older than 10 years. Certification on many of the legacy in-service devices has lapsed or was never part of the original engineering record and requires specialized engineering inspection by a qualified third party to certify.

The practices for working behind energy isolating devices have matured over the years with the evolution of Yukon Energy's safety program, and Yukon Energy is undertaking this project to ensure worker safety when performing maintenance, repair, and construction activities on the hydroelectric turbines. Yukon Energy's interpretation of section 2 of the Yukon Workers Safety and Compensation Board regulations is in line with other jurisdictions.

Why do this project this way?

Scheduling of inspections must coordinate with planned outages for operations and maintenance and capital projects such as overhauls and planned dewatering of penstocks. For devices where original design records are not adequate to grant certification based on design and construction, engineering inspections are required to determine their current state and what deficiencies need to be rectified for certification. Both the inspections and any required corrective work required for certification are included in the scope of this project.

APPENDIX 5.2A
DEFERRED PROJECTS >$2 MILLION ADDED TO RATE BASE

APPENDIX 5.2A: DEFERRED PROJECTS >$2 MILLION ADDED TO RATE BASE

5.2A-1: WRGS LONG-TERM WATER USE LICENSE RENEWAL

Table 5.2A-1: WRGS Long-term Water Use Licence Renewal Costs in Rate Base

Opening WIP	2025	2026	2027	Total Additions
$8,834,900	$1,773,000	$0	$0	$10,607,900

Project Description

The current Type A water use licence for the Whitehorse Rapids Generating Station (WRGS) expires on May 31, 2025. To continue to generate renewable hydroelectricity at the WRGS, Yukon Energy must have specific licenses, permits and authorizations in place. These include a water use licence from the Yukon Water Board (YWB), a *Fisheries Act* Authorization (FAA) from the Department of Fisheries and Oceans Canada (DFO), and a *Canadian Navigable Waters Act* authorization from Transport Canada.

The overall goal of the WRGS Long-term Water Use Licence Renewal project (WRGS Relicensing Project) is to obtain long-term (20-year) project authorizations for the continued operation of the WRGS, including the Lewes Control Structure, under licence terms and conditions that Yukon Energy operates those facilities under today. As part of this project, Yukon Energy is also seeking authorizations to complete emergency repairs to the Lewes Control Structure and Boat Lock after damage was sustained to them during the Southern Lakes flood in 2021.

The WRGS is located within the Traditional Territories of two Yukon First Nations with treaties: Kwanlin Dün First Nation (KDFN) and Ta'an Kwäch'än Council (TKC). Water in the Tàgä Shäw/Yukon River, which is used to generate hydroelectricity at the WRGS, comes from Tàkwädàdhà/Marsh, Tagish and Mén Chó Ch'akúx Anax Dul.adi Yé/Bennett Lakes, as well as from Aa Tlein/Atlin and other parts of the Southern Lakes watershed. These lakes and Yukon River are located within the Traditional Territories of KDFN, TKC, Carcross/Tagish First Nation (C/TFN) and the Traditional and asserted Territory of Taku River Tlingit First Nation (TRTFN).

C/TFN is also a Yukon First Nation with a treaty. TRTFN is a First Nation located in Atlin, British Columbia, with asserted rights in the Yukon in areas within the project area of influence.

Evolving Regulatory Landscape

The regulatory landscape is becoming increasingly complex. Multiple stakeholders are involved and strongly influence the relicensing process, which increases its complexity. The WRGS Relicensing Project interacts with many broader interests (e.g., land use planning), which introduces numerous factors outside of the control or scope of Yukon Energy. Navigating these factors requires collaboration and extended timelines and shared decision-making.

This relicensing process is the first time the WRGS has been assessed under the *Yukon Environmental and Socio-Economic Assessment Act* (YESAA) as Yukon Energy's current water use licence (HY99-010) was issued in 2000, three years before Parliament's approval of YESAA in 2003. The YESAA process is not especially designed for brownfield/relicensing projects, making it difficult for assessors to consider past project effects and potential future effects. This relicensing process is also the first authorization being sought for the facility under the *Fisheries Act* and first time a formal review under the *Canadian Navigable Waters Act* has been undertaken.

This relicensing process is also the first time that the facility has been assessed since KDFN, TKC and C/TFN have each entered into Final Agreements and Self-Government Agreements with the Yukon government (YG) and the Government of Canada. This is also the first time the Nations have been involved in an assessment process for the facility. TRTFN has not signed any land claim or Self-Government Agreement with the YG or the Government of Canada, with respect to its assertions in the Yukon.

First Nations are rightsholders. The approach taken by Yukon Energy during this relicensing process is a new way of doing business for Yukon Energy. It acknowledges that when Northern Canada Power Commission (NCPC) planned, designed and constructed the WRGS, it was done without the involvement of First Nations people and had substantial detrimental impacts to First Nations way of life. It also recognizes the rights and interests of TKC, C/TFN and KDFN citizens and beneficiaries, including their treaty rights under their Final Agreements, and that the ongoing operation of the facility continues to impact First Nations' way of life.

Yukon Energy maintains encumbering water use rights to operate the WRGS facility, which is reflected in the Final Agreements with the three Yukon First Nations involved. However, a successful permitting outcome requires trusting relationships, collaborative processes, alignment through non-regulatory agreements and follow-up monitoring. An encumbering right does not preclude regulators from considering First Nations interests in their determinations.

Strategic and Regulatory Approach

Based on the lessons learned exercise from the most recent Aishihik Generating Station hydro relicensing project, Yukon Energy strategically employed both regulatory and non-regulatory methods to address First Nations values and interests that Yukon Energy heard were important to First Nation governments in the project area.

The regulatory stream included operational considerations, identification of potential project effects on environmental and socio-economic valued components, and development of a revised monitoring and adaptive management plan to mitigate those effects. The non-regulatory stream included processes, structures and agreements to address other interests and values identified by the First Nations related to the project that could not be addressed solely through the regulatory process such as energy planning and reconciliation.

Governance

The WRGS Relicensing Project required a collaborative project governance structure both internal and external to Yukon Energy.

Externally, early engagement activities between Yukon Energy and First Nation Governments in the project area led to the development of the Senior Officials Group (SOG), the Negotiators Table (Main Table), and the Technical Working Group (TWG). Since the signing of the Framework Agreement in October 2022, technicians and senior officials from TKC, KDFN, C/TFN, YG and Yukon Energy have met over 70 times to listen and learn about each Parties' respective interests, exchange views and perspectives, and identify new ways to work together to address these values and interests.

Yukon Energy considered the interests shared by the Parties in the Project Proposal submitted in December 2023 to the YESAA Board's Whitehorse Designated Office (DO) for the ongoing operation of the WRGS hydro facilities. Yukon Energy acknowledges that alignment was not reached on all of the interests expressed, however, is committed to continuing to work First Nations in the project area and YG to continue to explore ways to address these interests through the WRGS Monitoring and Adaptative Management Plan (MAMP) and the Energy Agreements.

Internally, Yukon Energy governance included oversight by the Yukon Energy Board of Directors' Project Committee, as well as continued reporting to and approvals by the Yukon Energy Board of Directors. Yukon Energy's Senior Management Team provided oversight on the execution of the Yukon Energy Board-approved stages of work, including monitoring project progress and risks. Senior Management provides direction to the project team on the project approach and budget approvals within the overall Yukon Energy Board-approved stagegate budgets and participates in the multi-party governance as defined above.

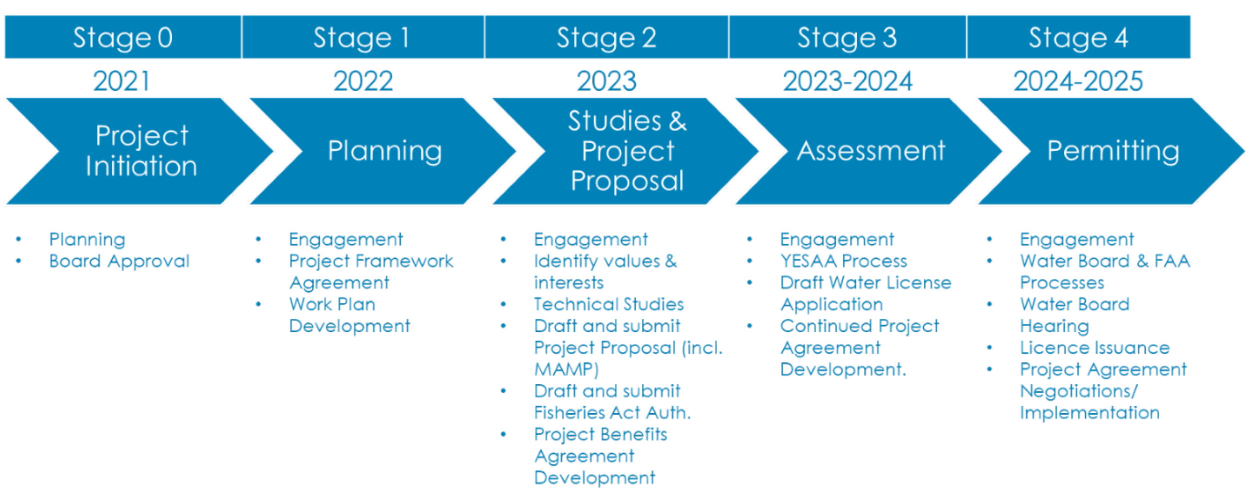
Project Approach

The approach for undertaking this project used a stagegate framework. Each stage focused on different elements of the project, based on requirements to meet the project objectives (i.e., renewed project authorizations, improved relationships, and monitoring and mitigation of project affects) and ends with a Yukon Energy Board Stagegate (decision point). The stages included:

- Stage 0: Project Initiation;
- Stage 1: Planning;
- Stage 2: Studies and YESAA Project Proposal;
- Stage 3: Assessment; and
- Stage 4: Permitting.

The figure below summarizes the project scope components that were planned at the start of the project. As the project progressed, the year in which each stage's activities were conducted and/or completed shifted depending on the progress made in prior stages, the scope of work required in each stage of work or factors outside Yukon Energy's control (i.e., regulatory delays).

Figure 5.2A-1: Project Scope Components and Stages of Activities



Project Activity Summary

This section summarizes key activities from the start of the project to April 2025.

Stage 0: Project Initiation

- Initiated in 2021.
- Assessment of existing studies and research in the project area that would help inform the baseline information needed as part of the WRGS Relicensing Project assessment and permitting processes.
- Drafting governance models and engagement plans.
- Assessing project risks and developing mitigation strategies.
- The Yukon Energy Board of Directors passed a resolution on December 8, 2021, directing Yukon Energy management to advance the WRGS Relicensing Project to Stage 1.

Stage 1: Planning

- Initial bilateral engagements with C/TFN, TKC and KDFN began in early 2022.
- A two-day governance workshop with participating representatives from TKC, C/TFN, KDFN, and YG was held in April 2022. The two-day workshop included discussions of project options, outcomes, and ways the Parties would work together throughout the WRGS relicensing process.
- Establishment of the SOG, Main Table and TWG structure and governance model.
- Regular TWG, SOG and negotiator meetings began to gather information about First Nations interests related to the project, assess project options, develop a shared technical work plan, schedule and budget, and collaboratively plan for the first round of public engagement on the project.
- Collaboration with First Nations and YG planning parties to procure technical advisory and support services for the TWG.
- A Framework Agreement between Yukon Energy, C/TFN, TKC, KDFN and YG was signed.

- A TWG Terms of Reference was signed. The TWG included representation from all Parties to the Framework Agreement and representatives from DFO.

- The Yukon Energy Board of Directors passed a resolution on June 1, 2022, directing Yukon Energy management to advance the WRGS Relicensing Project to Stage 2.

Stage 2: Studies and Project Proposal

- Regular TWG and SOG meetings with First Nations planning parties.

- Collaborating with planning parties to assess options related to project scope (i.e., status quo licence and operating conditions, or any combination of any the following three options: (1) raising the licenced Full Supply Level (FSL) by up to 30 cm; (2) lowering the licenced Low Supply Level (LSL) by up to 10 cm; and (3) changing late summer gate closure rules at the Lewes Control Structure).

- Working with planning parties to co-develop and initiate assessments and field studies required for the Yukon Environmental and Socio-economic Assessment Board's (YESAB) evaluation of project effects.

- Meetings with staff from assessment and permitting entities including YESAB, DFO and the YWB to discuss ways to efficiently work through each regulatory and permitting process.

- Regular meetings of the Main Table to negotiate the Energy Agreements.

- With planning parties, assessing and completing short-term improvements to fish passage in the WRGS Fish Ladder.

- Confirming the scope of the relicensing project with the planning parties to inform the YESAA assessment. It was decided by the planning parties that the scope of the WRGS Relicensing Project would be the renewal of Yukon Energy's existing WRGS water use licence under the same licence terms and operating conditions with a temporal scope of 25 years. Yukon Energy acknowledges that there was not consensus amongst the parties on this decision.

- Developing engagement materials for public and First Nation citizen engagement on the project.

- Hosting public open houses and meetings with interested stakeholders to share information and gather input on the proposed project.

- Preparing of Yukon Energy's YESAA Project Proposal and coordinating reviews by the planning parties.

- The Yukon Energy Board of Directors passed a resolution on November 8, 2023, directing Yukon Energy management to advance the WRGS Relicensing Project to Stages 3 and 4.

- The YESAA Project Proposal was submitted to YESAB's Whitehorse DO in early December 2023. Yukon Energy proposed the ongoing operation of the WRGS, including the Lewes Control Structure, under existing operating conditions. It also asked the DO to assess activities related to emergency repairs of the Control Structure and Boat Lock that were damaged as part of the 2021 Southern Lakes flood. The temporal scope of the Project Proposal was 25 years.

Stage 3: Assessment

- Participating in the Whitehorse DO's assessment process including responding to information requests. In Q1 2024, YESAB posted a message on the *YESAB Registry* website homepage stating that they would not be adhering to their legislative timelines for assessment processes. The Whitehorse DO extended the Seeking Views and Information Stage on Yukon Energy's WRGS Relicensing Project Proposal for two months beyond legislative timelines.

- Working with planning parties to advance the MAMP that would be necessary for the YWB permitting process.

- Drafting the YWB water use licence application and coordinating reviews by the planning parties.

- Ongoing meeting of the Main Table to negotiate the Energy Agreements.

- Ongoing meetings with the TWG and SOG, as needed to advance the project through the assessment and permitting processes.

- Continuing studies and research with the TWG that would inform mitigations to project effects and could be used to inform the YWB's permitting process.

- The Whitehorse DO issued their Evaluation Report on the WRGS Relicensing Project on January 2, 2025. The Whitehorse DO recommended to the Decision Bodies for the Project (YG, DFO and Transport Canada) that the project be allowed to proceed, subject to 39 specified terms and conditions to mitigate what the Whitehorse DO determined to be significant adverse environmental and socio-economic effects of the project. The Whitehorse DO also confirmed in its Evaluation Report that the temporal scope of the WRGS Relicensing Project be 25 years and that "Based on interpretation of the Yukon Environmental and Socio-Economic Assessment Act, and YESAB's current internal temporal scoping policy, the Designated Office does not have the authority to alter the temporal scope defined by the Proponent."[1]

- Territorial (YG) and federal (DFO and Transport Canada) Decision Bodies issued their respective Decision Documents on April 4 and April 7, 2025, two months later than planned. The YWB's permitting process cannot proceed without Decision Documents from Decision Bodies.

- In both of their respective Decision Documents, the territorial and federal Decision Bodies agreed with the Whitehorse DO's recommendation that the WRGS Relicensing Project can proceed, subject to a total 40 specific terms and conditions varied or added by the Decision Bodies.

Stage 4: Permitting

- Working with planning parties to modify regulatory applications and update the MAMP based on the outcome of the Decision Documents. An updated MAMP is required as part of the YWB permitting process.

- Signing the Energy Agreements (not completed at the time of this GRA Filing).

- Submitting, on October 30, 2024, a water use licence application to the YWB for the 20-year renewal of the existing WRGS water use licence, under the same licence terms and operating conditions. Yukon Energy's application was for a 20-year licence term as this was identified during negotiation of the Energy Agreements to be the longest length of licence that KDFN and TKC could find acceptable.
- Designing and initiating a process for individual compensation under the *Yukon Waters Act*.

- Preparing and submitting an application to the YWB for a 60-day renewal of the existing WRGS water use licence to allow for more time for the Yukon Energy's 20-year Application to be reviewed.

[1] Page 38 (pdf page 54) of the Designated Office Evaluation Report. Whitehorse Rapids Generating Station. Project Number: 2023-0167. January 2, 2025.

Responding to information requests and participating in this permitting process. Due to delays in the issuance of Decision Documents (less than two months from the expiry of the existing licence), Yukon Energy identified the application of a 60-day renewal of its existing licence as a critical and necessary step to ensure hydro operations at the WRGS facility could continue under existing authorizations while the 20-year water use licence application was being reviewed. Without the 60-day renewal there would not be enough time to complete all the steps necessary, or to fulfill the legislated timelines needed, to complete the permitting process for Yukon Energy's 20-year application.

- Responding to information requests about Yukon Energy's 20-year application and participating in the YWB permitting process (not completed at the time of this GRA Filing).
- Working with planning parties to develop and submit the application for a FAA and authorization under the *Canadian Navigable Waters Act.* Responding to information requests and providing supplementary information that may be requested by the regulators (not completed at the time of this GRA Filing).
- Receipt of all authorizations for the continued use of the WRGS hydro facility, including the Lewes Control Structure (not yet obtained at the time of this GRA filing).

First Nation Interests

First Nations in the project area have told Yukon Energy that their interests as it relates to the WRGS Relicensing Project include, but are not limited to:

- Acknowledgment and reconciliation.
- Chinook Salmon conservation and restoration;
- Collaboration and relationship building;
- Accountability and trust;
- Care for the fish, birds, mammals, amphibians and their habitats;
- Reconnection to culture, heritage, land and water;
- Economic opportunities, capacity, youth engagement and compensation; and

- Equity and energy planning.

A desired outcome of the relationships Yukon Energy is building through this project is that C/TFN, KDFN and TKC are directly involved and derive benefits in the operation of Yukon Energy's WRGS, including the following:

- Direct involvement in the development and execution of additional future scientific studies and the gathering of Traditional Knowledge that would be used equally to inform current and future operations of the Project.

- Regular involvement in the design, implementation and annual refinement of the project's MAMP, which would include the identification of new mitigation measures that can be used to reduce the effects of the project.

- Active involvement in contracting, procurement, training, education and employment opportunities that stem from operating the project and where First Nation citizens, beneficiaries and businesses derive value from these opportunities.

- Direct participation to inform, develop and implement Yukon Energy's stewardship actions that acknowledge the historical impacts of the WRGS's construction and First Nations' use, occupation, history and stories related to the project; advance reconciliation, support cultural activities and First Nations Way of Life; and restore a better balance between the operations of the facility and its effects on land, water and the environment.

Working together with First Nations to reduce the impact of facility operations and advance their interests in a meaningful way was reinforced as part of YESAA's *Evaluation Report* issued in January 2025, and Decision Documents issued in April 2025. While the Decision Bodies (YG, DFO and Transport Canada) agreed with YESAA's recommendation that the WRGS be able to continue to operate, it did so on the condition that Yukon Energy comply with 40 terms and conditions, the majority which reflect interests raised by the First Nations noted above and require ongoing collaboration with them to advance.

Implementing the 40 terms and conditions outlined by the Decision Bodies, as well as living the commitments made in the suite of Energy Agreements, will take considerable time, dedicated focused research and significant financing and human resources to fulfill. Costs to implement these terms and conditions each year will be allocated to Yukon Energy's operating budget, increasing the need for additional funding in this area of the business.

At the time of filing this GRA, a full cost estimate of fulfilling the 40 regulated terms and conditions has not been completed and costs have not been included in Yukon Energy's 2025, 2026 and 2027 operating budgets.

Energy Agreements

Success of the WRGS Relicensing Project requires several agreements to confirm alignment and pathways for addressing matters in the short- and long-term that First Nations' governments, Yukon Energy and YG have identified to be important as it relates to the ongoing operation of the facility. The key agreements include:

- **Framework Agreement** amongst the KDFN, TKC, C/TFN, Yukon Energy and YG. Signed in October 2022, it was designed to establish structures and processes for the negotiation of the Energy Agreements; promote long-term benefits and opportunities to the First Nations and their citizens, beneficiaries and businesses, including employment, training, and contracting opportunities relating to the operations and maintenance of the WRGS; outline the shared commitment to build a better future and better relationships with respect to the ongoing operation of the Project and in recognition of its importance in meeting the Yukon's renewable energy needs and goals; and address any other matter that the Parties may agree on.

- **Relationship Agreement** between the First Nation(s) and Yukon Energy and YG that, amongst other matters, would set out the processes and structures to guide the Parties as they work to develop and implement the Energy Agreements.

- **Reconciliation Agreement** between the First Nation(s) and YG that, among other matters, would set out YG commitments to support reconciliation.

- **Project Agreement** between the First Nation(s) and Yukon Energy relating to the operation of the Project that, among other matters, would identify economic benefits and opportunities for First Nations' citizens, beneficiaries and businesses related to the operation of the Project over the course of the upcoming water use licence term, and identify community compensation for the First Nations pursuant to the *Waters Act* (Yukon).

- **Monitoring Agreement** amongst the First Nation(s) and Yukon Energy to collaborate on the monitoring for the WRGS related to land, water, lu / łūge / xáat / fish and wildlife, plants and people, amongst other matters. This agreement would commit Yukon Energy to collaborate with Parties to: develop, implement, and regularly review and update the Project's MAMP; undertake additional studies and activities to gather and incorporate Traditional Knowledge into the operation of the Project; incorporate additional mitigations to reduce or eliminate Project-related effects over time as additional information continues to be collected; and implement stewardship activities.

At the time Yukon Energy's GRA was filed, negotiation of the Energy Agreements is nearing completion. While the Energy Agreements have not yet been signed, in August 2024, TKC, KDFN, YG and Yukon Energy affirmed their support in principle for the commitments and obligations set out in them with respect to the relicensing and operation of WRGS for the next 20 years. At the same time, the Parties confirmed their intention to recommend the ratification of the Energy Agreements as soon as practicable to each Party's respective board, councils and Cabinet.

The C/TFN negotiator has advised the other Parties that C/TFN does not support a long-term water use licence and, as a result, would not be party to the Energy Agreements. The other Parties respect C/TFN's position and welcome the opportunity to have future discussions with C/TFN, at their request, to discuss their involvement in processes and structure contemplated under the Relationship and Monitoring Agreements.

In Spring 2025, Yukon Energy and C/TFN re-engaged in bi-lateral meetings to discuss options for a bi-lateral agreement between Yukon Energy and C/TFN that would outline how the two Parties could continue to work together on activities related to the WRGS Relicensing Project should C/TFN determine that it is unable to join the Relationship and Monitoring Agreements at this time.

Discussions pertaining to the Energy Agreements and other potential bi-lateral agreements to date are without prejudice and do not bind any First Nation Government, YG or Yukon Energy from entering into the suite of agreements. Terms of all Agreements that would be entered into are confidential and intended to be legally-binding. Commitments made by Yukon Energy would be enforceable through default and dispute resolution clauses, and legal action.

Project Budget

Costs to the end of 2024 are actual costs and have primarily been related to the assessment and permitting processes and engagement with planning partners. The costs for 2025 are forecast costs to complete the licence application process and are inclusive of the extra effort and time associated with the 60-day licence renewal.

Table 5.2A-2: WRGS Cost Breakdown (2021-2025) ($Millions)

	2021	2022	2023	2024	2025	Total
Assessment	0.000	1.133	2.283	1.707	0.970	6.092
Project management	0.083	0.164	0.130	0.126	0.232	0.735
Engagement	0.000	0.564	1.593	0.442	0.188	2.786
Third party engineering	0.000	0.000	0.000	0.000	0.000	0.000
Yukon Energy internal cost	0.038	0.116	0.062	0.077	0.085	0.377
AFUDC	0.000	0.022	0.096	0.201	0.298	0.617
Total	**0.122**	**1.998**	**4.163**	**2.552**	**1.773**	**10.608**

Project Costs

- **Assessment:** Costs include creating the TWG's Terms of Reference, completing technical field studies, and developing the YESAA project proposal, the 60-day and 20-year YWB water use licence applications, and the FAA, as well as participation in those assessment and permitting processes (e.g., responses to information requests, providing supplementary materials, and participating in the public hearing).

- **Project Management:** Costs cover the project management consultant(s) who coordinate the SOG and TWG, support meetings with planning logistics, meeting facilitation and documentation, provide technical reviews of project materials, and manage delivery of group actions. They also handle reporting, budgeting, and procurement for WRGS Relicensing.

- **Engagement:** Costs involve facility rentals, catering and supplies for SOG meetings and TWG meetings, legal consultants for energy agreement negotiations, legal fees for advice throughout the assessment and permitting process, community engagement events and public engagement materials. Included in Engagement are costs related to the process and payments for individual and community compensation required under the *Waters Act* (Yukon) and other negotiated benefits to First Nations included in the Energy Agreements.

- **Yukon Energy Internal Costs:** Costs consist of Yukon Energy staff labour, travel and meal expenses, and support for activities in the preceding categories (i.e., project management, assessment, and engagement).

The WRGS 20-year licence has an average effective cost of $0.530 million per year.

5.2A-2: AGS 25-YEAR WATER USE LICENCE RENEWAL

Table 5.2A-3: AGS 25-Year Water Use Licence Renewal Costs in Rate Base

Opening WIP	2025	2026	2027	Total Additions
$6,764,800	$650,000	$1,450,000	$905,000	$9,769,800

Project Description

The water use licence for the Aishihik Generating Station (AGS) expires on December 31, 2027. To continue to generate renewable hydroelectricity for the Yukon at the AGS, Yukon Energy must have specific licences, permits and authorizations in place. This includes a water use licence from the YWB and a FAA from DFO.

The overall goal of the AGS 25-Year Water Use Licence Renewal (AGS Relicensing Project) is to obtain long-term project authorizations for the generating station.

Background

The AGS provides the only multi-year hydro storage and the largest winter peak hydro generation capability on the Yukon Integrated System. Renewal of the existing water use licence and FAA, are both required to authorize Yukon Energy to regulate the water levels at, and flows from, Aishihik and Canyon Lakes for the purpose of generating hydroelectricity at the AGS.

Starting in 2015, 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.

- In 2019, Yukon Energy applied for a 3-year renewal 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; the expiration date for the FAA was extended for three years.

- In 2020, Yukon Energy then commenced preparation of a new project proposal under the YESAA to support a long-term renewal of the authorizations for the AGS facility. Following a multi-party planning process, Yukon Energy submitted a YESAA Project Proposal for a 25-year licence renewal to the Haines Junction DO on July 10, 2020. An application for a 25-year licence renewal was subsequently filed with the YWB on May 31, 2021. The DO Evaluation Report was issued on June

18, 2021. In that report, the Haines Junction DO declined to assess the proposed licence renewal for the 25-year period requested by Yukon 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 YG and DFO.

As a result of these regulatory decisions, the YWB's jurisdiction to renew the AGS water use licence was confined to the 5-year period assessed by the DO, 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. The YWB conducted a public hearing in Haines Junction on November 21 and 22, 2022. Following the hearing, the five-year water use licence renewal was issued by the YWB on December 21, 2022, with the YG's approval. The FAA in place at the time was extended by DFO and has continued to be extended until mid-2025.

Previous GRAs

Costs related to the AGS Relicensing Project were initially reviewed as part of the 2017/18 GRA, and subsequently reviewed during the 2021 GRA and the 2023/24 GRA. Costs have been separated over time into three projects: (1) the three-year AGS relicensing project (January 1, 2020 to December 31, 2022), the five-year AGS relicensing project (January 1, 2023 to December 31, 2027), and 25-year AGS relicensing project (January 1, 2028 to December 31, 2052).

For the 2021 GRA, AGS Relicensing Project costs of $9.4 million were forecast to the end of 2022.[2] The costs incurred were for project management, compensation, stakeholder engagement, monitoring, permitting, committee work and AFUDC. Certain costs incurred prior to 2021 were considered foundational as they provided the basis for the documentation required to support a 25-year licence renewal.

In 2022, long-term renewal costs were separated into 5-year and 25-year renewal costs. The table below, developed for the 2023/24 GRA, shows the total costs incurred and the allocation of those costs to each of the identified licence renewal projects. The costs are forecast costs for 2024 and not total costs for the 25-year licence period as the table does not include forecast costs beyond 2024[3].

[2] Updates regarding work completed and project costs for the long-term licence were reviewed in detail in the response to YUB-YEC-1-90 filed during the 2021 GRA.
[3] Preliminary actual costs in 2024 consisted of $0.179 million relating to the five-year renewal and $0.138 million relating to the 25-year renewal.

Table 5.2A-4: AGS Costs reviewed during the 2023/24 GRA ($000)

	Annual Expenditures	Cumulative	3-Year Licence	Longer Term Cumulative	5-Year Licence	25-Year Licence
	A	B	C	D=B-C	E	F=D-E
2015	50	50		50		
2016	955	1,005		1,005		
2017	1,969	2,974		2,974		
2018	1,983	4,957		4,957		
2019	1,317	6,275	805	5,470		
2020	2,270	8,544	112	7,627		
2021	1,273	9,817		8,900		
2022	1,313	11,131		10,214	4,479	5,735
2023					40	811
2024 F					189	1,428
Total			**917**		**4,708**	**7,974**

YEC costs of $4,708,000 for the five-year licence renewal were reviewed by the YUB and included in rates following the 2023/24 GRA (by Board Order 2024-05). This included costs related to the FAA[4].

Renewal of the AGS water use licence as of January 1, 2028 for a long-term (25-year) period 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 Yukon Integrated System (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.

[4] See detailed analysis of the FAA in Appendix 5.2B.

- The AGS also provides 37 MW of dependable capacity to the YIS, which is more than one quarter of YIS maximum dependable generation capacity during the winter.

- 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, or under planning for development in the near-term.

- Prior to planning, permitting and development of any new alternative generation capability, including renewable supply options, Yukon Energy would need to rely on existing thermal generation to replace the energy and dependable capacity currently supplied 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. 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 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.

Engagement

The relicensing process includes a significant First Nation, stakeholder and regulatory engagement component. The engagement strategy focused on identifying First Nation and stakeholder values related to Aishihik Lake and its environment, as well as regulatory requirements related to the uses of Aishihik Lake, and using this information as context to evaluate alternatives for operation of the Project. The process was facilitated through the Steering Committee, Aishihik Advisory Committee (AAC) and Champagne and Aishihik Community Advisory Committee (CACAC).

Project Activities

This section summarizes the activities from 2015 to March 2025.

- **2015** – A project charter was approved by the Yukon Energy Board in August 2015. During the remainder of 2015, Yukon Energy proposed establishing a Consultative Committee (CC) consisting of multiple stakeholders and the Champagne and Aishihik First Nations (CAFN). A protocol agreement was signed between Yukon Energy and CAFN documenting the guiding principles of the relicensing co-management, and a co-management steering committee consisting of one CAFN member and one Yukon Energy member was established. The Aishihik Advisory Committee (AAC) consisting of representatives of the CAFN, Yukon Energy and multiple stakeholders was established and co-chaired by CAFN and Yukon Energy. The role of the AAC was to explore and propose the optimal lake operations that considered the interests of all the stakeholders and then form the basis of Yukon Energy's licence application. The actual project expenditures in 2015 were $50,149.

- **2016** – The AAC met to discuss project issues, create operational alternatives and identify information gaps. CAFN set up the Champagne and Aishihik Community Advisory Committee (CACAC) to provide advice on the introduction of CAFN values and traditional knowledge to the process and, provide input to the scope and interpretation of the baseline studies. An agreement to fund the Traditional Knowledge project was signed between CAFN and YEC.

  Actual project spending for 2016 was $0.955 million. A significant portion related to the expansion of the scope of the impact assessment studies.

- **2017** – Technical working groups were established to advise the project team. Public meetings were held in both Whitehorse and Haines Junction. Yukon Energy engaged with CAFN leadership to request a formal start to negotiation of a compensation/benefits agreement. The majority of the field work and draft baseline reports for the environmental studies were completed in 2017.

  Due to a delay in delivering the Traditional Knowledge project and CAFN issues related to project management capacity, the project schedule was adjusted in Q1 2018. A new schedule was developed that resulted in a 3-month delay in completing the YESAB project proposal. This delay put significant pressure on the project to be delivered by the end of 2019, when the current water use licence expired.

  Actual project spending for 2017 was $1.969 million, with impact assessment continuing to be the highest category.

  2018 – Considering the importance of support for the project by CAFN citizens, and building and maintaining good relationship between CAFN and YEC, CAFN and YEC agreed to work together on securing social license from CAFN citizens through a participatory alternative selection process. Following workshops and discussions in fall 2018, the parties were not able to reach agreement on a preferred operational alternative for the lake. With limited time available to complete assessment and permitting processes, prior to the expiry licence in December 2019, Yukon Energy made a decision to proceed with completion and filing of the YESAB application based on a slightly modified version of 'status quo' lake operations. Following Yukon Energy's decision to proceed with the preparation of the YESAB application, CAFN declined to participate in further co-management team meetings. The YESAB project proposal was completed and ready to file on December 28, 2018.

CAFN representatives on the steering committee did not secure a mandate from Chief and Council to initiate project benefit negotiations with Yukon Energy related to the facility relicensing. Instead, CAFN Chief and Council planned to negotiate project benefits directly with YG. YEC engaged with YG to support the benefits negotiation, with the objective of minimizing the impact on the relicensing process.

Actual project spending for 2018 was $1.983 million, a significant portion of which was on baseline studies, effects assessment and preparation of the YESAB submission.

- **2019** – A YESAB project proposal for a 3-year licence renewal was completed and filed on February 20, 2019. The term of the licence renewal was reduced to 3 years to reduce the risk related to completing the assessment and permitting processes prior to the end of 2019 when the water use licence and FAA would expire. An application for a 3 year licence renewal with the YWB was filed on March 25, 2019. ADFO request for review was also prepared and submitted on March 15, 2019.

  During Q1 2019, Yukon Energy's Chair re-engaged with the Chief of CAFN. A letter agreement was signed on March 14, 2019 documenting the scope of engagement between the parties on both the 3-year and subsequent longer-term (25-year) licence renewals.

  The Haines Junction DO issued its evaluation report on the 3-year licence application on September 4, 2019, and a Decision Document was subsequently issued by the Decision Bodies.

  A separate application for a 60-day renewal of the existing water use licence (to February 28, 2020) was submitted October 18, 2019 to ensure that that the water use licence did not expire at the end of 2019 (the renewal was provided December 18, 2019). The 60-day renewal was granted to the end of February 2020. DFO issued a 3-year extension to the AGS FAA on December 20, 2019.

  Actual project spending for 2019 was $1.317 million with a focus on the 3-year renewal.

- **2020** – The public hearing on the 3-year licence renewal application was held in January 2020 in Haines Junction. The YWB issued a 3-year water use licence renewal on February 19, 2020, with an expiry date of December 31, 2022.

Work continued at the technical and negotiating tables to advance planning and development of a long term YESAA project proposal, as well as benefits and reconciliation negotiations between YG and CAFN, with Yukon Energy's participation. The long-term YESAA project proposal was submitted to the Haines Junction YESAA DO on July 12, 2020.

Over the course of 2020, YEC engaged with CAFN, YG and the Government of Canada (DFO) to explore matters related to the long-term YESAA project proposal, the pending regulatory applications, the development of a revised MAMP, and the negotiation of a non-regulatory agreement covering benefits, compensation, and reconciliation matters.

Actual project spending for 2020 was $2.270 million. The majority of costs were split between baseline studies, assessment and permitting, and early implementation and monitoring.

- **2021** – The water use licence application was submitted on May 31, 2021. The YESAA evaluation report for the project was issued by the Haines Junction DO on June 18, 2021. The evaluation report included terms and conditions that restricted the temporal scope of the assessment from 25 years to 5 years. This limitation in effect limited the term of any water use licence granted by the YWB to 5 years.

  YG and the DFO issued a consolidated Decision Document on October 22, 2021, that retained the 5-year temporal scope. As such, an additional assessment and permitting process would be required to secure a 25-year water use licence for the AGS facility.

  Actual project spending for 2021 was $1.273 million.

- **2022** – A revised application for a 5-year water use licence was submitted to the YWB on April 8, 2022. The 5-year FAA application was submitted August 10, 2022.

  The YWB hearing was held in Haines Junction in 2022. With project agreements between YEC, CAFN and YG established, this process unfolded in a collaborative manner between the parties. The renewed water use licence was issued on December 20, 2022.

  Actual project spending for 2022 was $1.313 million.

- **2023** – With the water use licence renewal issued at the end of 2022, attention turned to renewal of the FAA in Q1 2023. DFO provided a short-term extension of the existing FAA to the end of 2023.

Yukon Energy began implementation activities related to the renewed water use licence for the AGS. Yukon Energy completed an update to the MAMP. This was submitted to the YWB on April 30, 2023.

DFO replied later in the third quarter with clarifications regarding what it needed to consider the FAA application complete. YEC, YG, CAFN met with DFO in September to review the response. The outcomes of this meeting included agreement for Yukon Energy to apply for a short-term FAA extension through to June 2024, such that the review of the FAA renewal application could be concluded. This received approval of DFO in December.

Actual project spending for 2023 was $0.851 million.

- **2024** – Yukon Energy continued to advance the development and review of the FAA application in collaboration with CAFN and YG. Project activities were focussed on addressing DFO's information requests on the FAA renewal application and collaborating with CAFN and YG on this process. Aside from the FAA, AGS-related activities focused on implementing the MAMP developed for the 5-year licence. The Draft Long-term MAMP, a key filing required as part of the 5-year water use licence process, was also completed following an intensive 4-month collaboration with CAFN and YG.

  Actual project spending for 2024 was $0.317 million, with more than half related to the FAA renewal.

- **Current Project Status** – Activities since 2015 have resulted in completion of much of the work required to support development of the long-term licence renewal. Costs attributable to the longer-term licence to the end of 2024 net $6.765 million. The existing licence expires at the end of 2027. Forecast spending for 2025-2027 is $3.005 million. Spending in the test years is to account for costs related to the development of the long-term YESAA Project Proposal, water use licence and FAA, and includes costs related to collaborating with CAFN on each of these regulatory filings and processes. While the forecast costs are subject to uncertainty, best estimates have been made based on recent experience of AGS and other water use licence renewals. Next steps include:

  - YESAA Project Proposal Development;
  - YESAA Assessment;
  - Water Use Licence Application Development;

- Consideration of Individual Compensation;
- Water Use Licence Application Defense;
- FAA Application Development; and
- FAA Application Defense.

Subject to conditions of the AGS Collaboration Agreement, parties are expected to participate in relicensing processes with their own funding.

Overall, Yukon Energy's expectation is that the project objectives (i.e., renewed FAA and water use licence) will be achieved on schedule and within the budgeted amount. The Agreements, current working relationships with CAFN and YG, and the fact that many matters were resolved during the current 5-year licence are key factors influencing this assessment.

Yukon Energy will be pursuing a 25-year authorization, as contemplated by the Agreements signed in 2022.

Cost Control Measures

Management has implemented measures to improve expenditure control, including refining the processes for forecasting, monitoring and adhering to stagegate and project budgets, and employed specific measures for the AGS Relicensing project.

These measures included:

- Providing specific guidelines and training on project management practices to be employed in large planning projects;
- Improving budget tracking and progress monitoring by implementing monthly project reporting requirements on actual and forecast expenditure, scope, and target milestones/timelines;
- Providing additional administrative support to project managers to ensure consultant/contractor work is billed and received in a timely manner to improve 'actual expenditure' reporting accuracy and subsequent forecasting accuracy;

- Providing support from the finance team to project managers in the development of budget forecasts (e.g. accurate AFUDC estimation) and standardized budget reporting; and

- Clarifying administrative requirements for project managers to ensure clarity and accuracy of information in the financial system for efficient reporting and analysis.

To provide more comprehensive cost control of the AGS Relicensing Project budget, additional measures will also be employed for this project in particular, including:

- Requiring weekly consultant workplan/effort forecasts;

- Cross-referencing weekly consultant workplan forecasts with monthly invoices to identify variances in expected billing; and

- Monthly analysis of key budget indicators, mainly through comparison of percentage task completion with percentage of budget deployed for both consultant and internal labour tasks.

Project Budget

The AGS Relicensing Project budget is complex due to the scope changes that included both an unanticipated 3-year licence renewal and an unanticipated 5-year licence renewal. As described earlier, the long-term licence renewal included costs being reallocated to their respective shorter-term licences. The YUB has previously reviewed costs relating to the 3-year licence and the 5-year licence (including costs relating to the FAA). In this GRA, Yukon Energy anticipates completion of the long-term licence during the test years and is requesting the cost of the long-term licence be approved as part of rate base.

The following table summarizes all costs from beginning of the Aishihik relicensing process in 2015 to the end of 2024, and forecast costs for 2025 through 2027. Costs relating to the 3-year licence and 5-year licence (including the AGS FAA) are included to show total AGS licence renewal costs.

Table 5.2A-5: Total AGS Costs (2015 to 2024 Actual, and 2025-27 Forecast) ($000)

($ 000s)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Project Management	25	54	66	130	132	147	39	22	1	-	100	150	125	**991**
Assessment & Permitting	-	710	1,307	1,442	704	1,403	746	911	39	124	270	825	480	**8,962**
Engagement	25	182	543	286	268	470	206	92	627	-	80	130	100	**3,010**
AFUDC	-	9	53	124	212	250	282	288	184	193	200	210	200	**2,205**
Contingency	-	-	-	-	-	-	-	-	-	-	-	135	-	**135**
Project Total	**50**	**955**	**1,969**	**1,983**	**1,317**	**2,270**	**1,273**	**1,313**	**851**	**317**	**650**	**1,450**	**905**	**15,302**

The allocation of the total AGS licence costs is shown below.

Table 5.2A-6: Allocation of Total AGS Relicensing Costs

	Cost ($ 000)
3-Year Licence	917
5-Year Licence	3,903
AGS FAA (5-yr renewal to rate base in 2025)	714
Long-term Licence	9,770
Total	**15,302**

The costs for the 3-Year licence and the 5-Year licence include FAA extensions and have been approved for inclusion in rate base by the YUB in prior GRAs. For the 5-Year licence renewal from the start of 2023 to end of 2027, the YUB approved $4.708 million of costs in the 2023/24 GRA; however, due to the FAA renewal process being extended in various stages into 2025, only $3.903 million of 5-Year AGS licence renewal costs was added to rate base at the end of 2022.

A forecast $0.714 million for 5-year FAA renewal costs has been disaggregated from the AGS water use licence renewal as the authorization was still in-progress in 2025, and is in the 2025-2027 GRA as a separate deferred project cost.[5] The long–term licence costs include securing the water use licence and FAA renewals that start after the end of 2027.

AGS licence costs for the 3-Year licence and the 5-Year licence (including the FAA) have an average effective cost of $0.692 million per year.[6]

The AGS long-term licence has an average effective cost of $0.391 million per year.

[5] It is noted that some of the forecast $0.650 million AGS 25-year license renewal costs in 2025 may be attributable to the AGS 5-Year FAA renewal.
[6] Calculated as 3-year licence costs of $0.917 million plus 5-year licence costs of $3.903 million plus AGS FAA costs of $0.714 million, divided by 8 (the number of years these costs covered).

5.2A-3: MGS WATER USE LICENCE RENEWAL

Table 5.2A-7: MGS Water Use Licence Renewal Costs in Rate Base

Opening WIP	2025	2026	2027	Total Additions
$5,654,800	$1,640,000	$0	$0	$7,294,800

Project Description

The current Type A water use licence for the Mayo Generating Station (MGS) expires on December 31, 2025.

To continue to generate renewable hydroelectricity at the MGS, Yukon Energy must have specific licenses, permits and authorizations in place. These include a water use licence from the YWB, and a FAA from DFO.

The MGS Water Use Licence Renewal (MGS Relicensing Project) will obtain a 5-year renewal of the MGS water use license and FAA as a first step to advance a long-term 25-year renewal in a subsequent renewal application. The project also includes replacement/refurbishment of the Mayo Lake Control Structure with provision for fish passage and removal of coffer dam remnants. The scope of the removal of the coffer dam remnants is similar to what was previously proposed as part of Phase 1 of the Mayo Lake Enhanced Storage Project (MLESP). The MGS Relicensing Project does not provide for changes to the LSL previously proposed as part of Phase 2 of the MLESP.

Evolving Regulatory Landscape

The regulatory landscape has become increasingly complex in recent years. The YESAA process is not designed for brownfield or relicensing projects, making it difficult for the assessors to consider past project effects and potential future effects.[7]

The role of reconciliation and Indigenous relationships is evolving and taking on greater importance within the context of regulatory processes. The need to address reconciliation means that project assessment and permitting processes have become more complex and may need to include processes to address matters that fall outside of the jurisdiction of regulators. This provides confidence for all parties that these matters can be addressed appropriately.

[7] This was observed during the water use licence renewal assessment for the AGS, where YESAB reduced the temporal scope of the assessment from the requested 25-year term to a 5-year term, to provide time to address and resolve perceived uncertainties.

First Nation Interests

The MGS was constructed by NCPC in the early 1950s near the Village of Mayo and within the Traditional Territory of the Na-cho Nyäk Dun (FNNND). When NCPC built the MGS, it was done at a time before First Nation titles and rights were recognized in the Yukon and without FNNND involvement. FNNND has noted a number of unresolved issues related to the construction and ongoing operation of the facility in their traditional territory. As some of these issues fall outside the scope of regulatory processes – non-regulatory pathways or tables have been implemented to ensure that there is a venue to explore and find resolution for these issues (e.g., through development of project benefit agreements or joint workplans to advance interests).

It is critical to build alignment and trust with FNNND in order to efficiently and effectively advance project relicensing activities.

YEC and FNNND are interested in development of an ongoing relationship and dialogue regarding energy planning. Yukon Energy is also planning to undertake a number of sustaining capital projects related to the refurbishment of MGS infrastructure in FNNND's traditional territory within the next several years. This presents challenges in advancing individual sustaining capital projects prior to establishment of a mutually agreeable pathway for addressing broader energy interests, and is a major contributing factor as to why Yukon Energy agreed to the FNNND's request to pursue a 5-year water use licence at this time.

The FNNND has several other priorities outside of energy that require time and attention. These competing priorities limit resource capacity and responsiveness from the First Nation. Yukon Energy has explored viable options for supporting FNNND priorities through relationship building discussions early in the engagement as well as more formally as part of project agreement discussions.

Finally, through its existing water use licence, Yukon Energy maintains encumbering rights (an 'encumbering right') to operate the MGS facility, as reflected in the FNNND's Final Agreement. A successful permitting outcome requires trusting relationships, collaborative processes, alignment through non-regulatory agreements and follow-up monitoring. An encumbering right does not preclude regulators from considering First Nations interests in their determinations.

Strategic and Regulatory Approach

This Project strategically employs both regulatory and non-regulatory methods to address values and interests that Yukon Energy heard were important to FNNND. The regulatory stream included operational considerations, identification of potential project effects on environmental and socio-economic valued components, and development of a revised monitoring and adaptive management plan to mitigate those effects. The non-regulatory stream is expected to include processes and structures to address other interests and values identified by FNNND related to the project that could not be addressed solely through the regulatory process (e.g., energy planning and other actions focused on reconciliation).

Governance

The Project required a collaborative project governance structure both internal and external to Yukon Energy.

Internally, Yukon Energy governance included oversight by the Yukon Energy Board of Directors' Project Committee, as well as continued reporting to and approvals by the Yukon Energy Board of Directors. Yukon Energy's Senior Management Team provided oversight on the execution of the Yukon Energy Board-approved stages of work, including monitoring project progress and risks. Senior Management provides direction to the project team on the project approach and budget approvals within the overall Yukon Energy Board-approved stage gate budgets and participates in the multi-party governance.

Externally, engagement activities between Yukon Energy, YG and the FNNND led to the development of a Senior Officials Group (SOG) and a Technical Working Group (TWG). The multi-party governance structure ensured meaningful opportunities for engagement for stakeholders and rightsholders. The high-level objectives of the engagement approach included:

- Share information about the role the MGS plays in providing Yukoners with renewable, sustainable and affordable electricity now and achieving the Yukon's 2030 climate change objectives.

- Obtain alignment amongst Yukon Energy, FNNND and YG leaders on the scope and strategic approach of the relicensing process.

- Gather feedback from all levels of government, energy interest groups, First Nations citizens and Yukoners about their specific interest and values in the existing facility and in the relicensing process.

- Collaborate with the First Nation, municipal and Yukon governments to share information about the relicensing process with their citizens and constituents. Emphasize how Yukon Energy, FNNND governments and are working together to ensure the interests of Yukon people are considered and used to guide the relicensing process.

- Provide information about the assessment of existing and potential future effects of the MGS operations on interests and values identified earlier in the engagement process.
- Outline how potentially significant adverse effects are being/will be mitigated.
- Outline the scope and scale of the MAMP.

Project Approach

A stagegate framework approach was used for undertaking the project. Each stage focused on different elements of the project, based on requirements to meet the project objectives (i.e., renewed project authorizations, project agreements, relationship improvement) and ends with a Yukon Energy Board Stagegate (decision point). The stages included:

- Stage 0: Project Initiation;
- Stage 1: Planning;
- Stage 2: Studies and YESAA Project Proposal;
- Stage 3: Assessment; and
- Stage 4: Permitting.

The overall scope of the project is focused on the activities required to secure the water use licence and FAA authorization required to continue operation of the MGS for 5-years following the end of 2025, as well as replacement/refurbishment of the Mayo Lake Control Structure with provision for fish passage, and removal of coffer dam remnants. The project scope included four major tasks that will be used to execute the project (as outlined in Table 5.2A-8).

Table 5.2A-8: Project Scope and Major Tasks

Task	Description
Task 1 – Project Management	• Project planning and execution. • Monitoring and Management of scope, schedule, and budget. • Risk strategy, risk assessment and treatment plan updates. • Oversight of the production of key deliverables and ensuring alignment with the project strategy. • Communications with project team and internal stakeholders. • Progress reporting to Yukon Energy Board of Directors and Projects Committee (quarterly). • Progress reporting to Yukon Energy Senior Management Team (monthly).
Task 2 – Assessment & Permitting	• Definition of project components (project description). • Conduct gap analysis of studies and analyses to support assessment and permitting. • Create a plan to collect outstanding data gaps that are required for assessment and permitting and/or align with the technical and socio-economic values identified through engagement. • Conduct studies to fill information gaps and adequately understand Project effects. • Relocate the water level gauge from the outlet to Mayo Lake proper. • Prepare YESAA Project Proposal. • Respond to information requests throughout the YESAA Process. • Prepare applications for project authorizations. • Shepherd applications through regulatory processes.
Task 3 – Engagement	**Government Engagement** • Create and maintain project oversight at the leadership and senior officials' levels. • Development of Project Framework Agreement. • Development of Project Benefits Agreements with First Nations. • Develop and lead Engagement Working Group. • Develop and implement engagement plan. **Stakeholder Engagement** • Create dialogue about the relicensing process and how individuals and stakeholder groups can get involved at different stages of the process. • Gather feedback about specific interests and values in the facility and projects. • Share information about how Yukon Energy proposal has considered input throughout the process.
Task 4 – Engineering	• Prepare a project plan for replacement/refurbishment of the Mayo Lake Control Structure and removal of the coffer dam remnants. • Advance engineering design to support assessment and regulatory applications.

Schedule

The current water use licence expires on December 31, 2025. The figure below summarizes the project scope components as planned at the start of the project. As the project progressed, targeted timelines for completing each stage's activities shifted depending on the progress made in prior stages, and the scope of work required in each stage.

Table 5.2A-9: MGS Project Stages and Activities

Stage	Stage 1	Stage 2	Stage 3	Stage 4	Stage 5
Main Activities	Planning	Year 1 Studies	Year 2 Studies & YESAA Project Proposal Development	Assessment	Permitting
Timeline	March 2022 – May 2022	June 2022 – December 2022	January 2023 – September 2023	October 2023 – October 2024	November 2024 – December 2025

Project Activities

This section details Project activities from 2022 to March 2025.

- **2022** – Activities included securing meetings with FNNND, including a leadership engagement with the Chief and Council held on June 7, 2022. The key focus was to establish a draft Framework Agreement to support the work for this project as well as other activities in FNNND's Traditional Territory. On December 12, 2022, the lead negotiating teams for FNNND, YG, and Yukon Energy drafted the terms of a Framework Agreement to advance processes for current and future projects involving the three parties.

- **2023** – Activities focused on establishing processes for development of a YESAA Project Proposal, including discussions with FNNND on environmental and socio-economic priorities related to MGS, executing field studies and research programs, initiating engagement activities, and confirming YESAA Project Proposal assessment processes. Negotiator meetings involving Yukon Energy, YG, and FNNND progressed the Framework Agreement. Stakeholder engagement continued through 2023, with Project overviews provided to local and territorial stakeholders.[8]

[8] This included the following: Yukon First Nations Salmon Stewardship Alliance; Village of Mayo; Canadian Parks and Wilderness Society; Yukon Conservation Society; Klondike Placer Miners Association; and Yukon Fish and Wildlife Management Board.

- **2024** – In February 2024, FNNND passed a General Meeting resolution to support a shorter-term licence (instead of a longer-term licence) for MGS based on the strain that civil, licensing and re-licensing projects in FNNND territory was putting on FNNND staff, community, and consultant resources.

  Following this, the Yukon Energy Board passed a resolution aligned with FNNND's desire to pursue a 5-year YESAA assessment and directing project staff to return to the Yukon Energy Board with a revised budget and workplan. Project staff initiated rigorous cost control and realized a significant reduction in actual project costs.[9]

  Due to the decision to pursue assessment and permitting of a 5-year licence term, in June 2024 YG negotiators advised Yukon Energy and FNNND that they no longer had the mandate to be a Party to the energy agreements contemplated in the MGS Framework Agreement.

  With a reduced licence length, benefits provided under the agreements now centre on:

  - Processes for ongoing collaboration with FNNND and its development corporation on items related to MGS hydro operations, Yukon Energy projects in FNNND's traditional territory, and Yukon Energy's energy resource plans, and new energy projects in the next 5 to 10 years.
  - Monitoring and mitigation of MGS project effects, including ongoing collaboration on the development and updates to the MAMP.
  - Procurement and contracting opportunities related to MGS monitoring and other Yukon Energy projects in the traditional territory in accordance with Yukon Energy's Procurement Policy.
  - Community compensation required under the *Waters Act* (Yukon).
  - Areas where Yukon Energy's existing operating budgets can be utilized (e.g., sponsorships) or repurposed (e.g., advertising) to advance a priority interest of the First Nation during the 5-year licence period.

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[9] Stages 1-3 were completed approximately 36% under budget. The proposed Stage 4/5 Budget for relicensing costs is about 2/3 of the original budget forecasted as part of the initial Charter.

Financial commitments made by Yukon Energy will reflect the smaller size (i.e., capacity) of the MGS compared to the WRGS and AGS facilities, and the 5-year licence length.

- **Current Project Status** – A Project Proposal was submitted to the Mayo DO on July 17, 2024. The project has progressed through the YESAA assessment process, and an evaluation report was issued by the Mayo DO on April 23, 2024. Yukon Energy has also filed a water use licence application with the YWB (that includes a draft MAMP). The water use licence application is currently in the adequacy review stage with the YWB. While licensing processes present potential risks to the project timeline, the delivery date for the water use licence by the end of 2025 remains feasible.

  Timely acquisition of a renewed FAA has emerged as a schedule risk due to uncertainty with DFO regulatory processes. The risk of regulatory delays will continue to be mitigated with effective collaboration and communication with project partners, particularly the FNNND. Negotiators and senior officials of FNNND and Yukon Energy continue to collaborate on drafting of an Energy Agreement or similar instrument, with the goal of completing an agreement in 2025.

Project Budget

The MGS Relicensing Project has two major cost components: (1) the MGS relicensing process; and (2) the relevant costs transferred from the Mayo Lake Enhanced Storage (MLESP) project (costs that support the removal of coffer dam remnants). See below and MLESP project details in Appendix 5.2A-4).

- **MGS Relicensing Budget** –The original budget for the MGS Relicensing Project was $8.0 million.

  Stages 1-3 of the MGS Relicensing Project had a Board of Directors approved budget of $4.7 million. Management and staff responded to the shortened assessment term and further constrained spending so that the budget was underspent by $1.5 million with actual costs of $3.2 million.

  Stages 4 and 5 were originally budgeted at $3.3 million. Considering the shorter assessment term, Yukon Energy reduced the Stagegate 4 and 5 budget to $2.060 million.

  An adjusted project budget for relicensing, considering the shorter assessment term, forecasts an overall total project budget of $4.959 million as compared to the original budget of $8.0 million. Much of the savings come from underspending in Stages 1-3, and adjustments in Stages 4/5 to reduce frequency of TWG meetings (from monthly to quarterly), reduced internal labour, and reduced scope for studies to reflect the level of effort required for a 5-year licence.

MGS 5-Year Licence Renewal Costs

Costs to the end of 2024 are actual costs and have primarily been related to permitting and assessment. The costs for 2025 are forecast costs to complete the licence application process.

Table 5.2A-10: MGS 5-Year Renewal Costs

($ Millions)	2023	2024	2025	Total
Assessment	1.138	1.368	0.556	**3.062**
Project Management	0.013	0.004	-	**0.017**
Engagement	0.113	0.261	0.673	**1.047**
Yukon Energy Internal Cost	0.115	0.221	0.211	**0.547**
AFUDC	0.013	0.073	0.200	**0.286**
Total	**1.391**	**1.928**	**1.64**	**4.959**

- **Assessment:** Costs cover the project management consultant(s) who coordinate the TWG, and support meetings, technical reviews and manages actions. They also handle reporting, budgeting, procurement, and permitting for the project. Additionally, costs include developing the YESAA project proposal, completing technical field studies and water use licence application and FAA-related expenses.

- **Engagement:** Costs involve facility rentals, catering and supplies for SOG meetings and TWG meetings, legal consultants for energy agreement negotiations, legal fees for advice throughout the assessment and permitting process, community engagement events and public engagement materials. Included in engagement are costs related to the process and payments for individual and community compensation required under the *Waters Act* (Yukon), and other negotiated benefits to First Nations included in the Energy Agreement or other similar instrument.

- **Yukon Energy Internal Costs:** Costs consist of Yukon Energy staff labor, travel and meal expenses and facility rentals for public engagement events, as well as staff leadership, participation, and support for activities in the preceding categories (i.e., project management, assessment and engagement).

- **Mayo Lake Enhanced Storage Project Transferred Costs**[10] – Costs of that MLESP project related to recommending (as a first phase) removal of coffer dam remnants without any other

[10] In February 2022, the Yukon Energy Board approved including the activities required to remove the Mayo Lake Control Structure coffer dam remnants in the Mayo water use licence renewal project description and applications for the YESAB, YWB, and DFO processes as part of the broader relicensing for the MGS. Removal of the coffer dam remnants, which was previously part of the MLESP, will provide at least 1.7 GW/year additional renewable energy on average without any MGS water use licence changes to enhance Mayo Lake storage. This approach will allow for consideration of additional options in the future, such as dredging the outlet channel of Mayo Lake and a change in the LSL of Mayo Lake, should they be appropriate.

MLESP changes would secure at least 1.7 GWh/year of added long-term average renewable generation and were determined to be applicable to the current MGS Relicensing Project. Total costs of $2.336 million for removal of coffer dam remnants, as detailed below, were transferred from the MLESP to the MGS Relicensing Project, enabling the balance of the MLESP to be cancelled (see the MLESP business case for more details as to options considered, and how the option selected reduces AFUDC and addresses concerns identified by the Board in the 2023/24 GRA process).

Table 5.2A-11: MLESP Project Transferred Costs

($ Millions)	Actuals
Assessment	1.921
Project Management	-
Engagement	0.029
Yukon Energy Internal Cost	0.139
AFUDC	0.248
Total	**2.336**

As noted, the above coffer dam remnant removal costs are expected to produce a long-term average renewable energy benefit equal to at least 1.7 GWh/year of diesel energy displacement, and therefore, could be amortized over a much longer term than the MGS 5-Year licence renewal. This option for amortization of these costs can be considered further during the 2025-2027 GRA review.

- **Total Project Costs -** As Yukon Energy made the decision that combining the two components was appropriate, it results in a total project cost forecast for the MGS water use license renewal of $7.295 million as detailed below.

Table 5.2A-12: MGS Relicensing Project Total Costs

($ Millions)	Total
Assessment	4.983
Project Management	0.017
Engagement	1.076
Yukon Energy Internal Cost	0.685
AFUDC	0.534
Total	**7.295**

The MGS 5-Year license has an average effective cost of $1.459 million per year.

5.2A-4: MAYO LAKE ENHANCED STORAGE PROJECT

Table 5.2A-13: Mayo Lake Enhanced Storage Project Costs in Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$0	$0	$0	$2,267,200

Project Description

The Mayo Lake Enhanced Storage Project (MLESP) cost of $2.267 million is the actual costs for planning work on this project to February 2022, net of costs of $2.336 million to February 2022 for coffer dam remnant removal that have been transferred to the MGS Relicensing Project. It is proposed that these MLESP costs be added to rate base in 2024, as a cancelled project with little-to-no probability of offering a net economic benefit to ratepayers based on current information and also given Board Order 2024-05 directions in paragraph 312 for cancelled projects. It is proposed that these costs be amortized over a 10-year period, as per the approach approved in the 2023/24 GRA for the canceled Southern Lakes Storage Enhancement Project.

Historical Activity

The Board in Board Order 2024-05 following the 2023/24 GRA, states at paragraph 334, "Accordingly, at the time of its next GRA, YEC is directed to provide with its application a summary of the historical activity and current status for each of the Whitehorse water use licence renewal, Mayo Generating Station water use licence renewal, and the Mayo Lake Storage and 2024 Resource Plan projects and the same information for any other project for which significant balances of CWIP (such as those projects identified in paragraphs 247-248 above) are forecast to remain at the end of the next test period. For the Mayo storage project, YEC is to treat this project similarly to the Atlin project discussed in paragraph 326 above."

As reported in the 2012/13 General Rate Application, the MLESP sought to amend the MGS water use licence to secure additional storage through 1 metre of added drawdown (i.e., lowering the Licensed LSL of the lake by 1 metre) by changing the existing licenced controlled storage range of 2.59 metres (663.25 to 665.84 metres) to a new licenced controlled range of 3.59 metres (662.25 to 665.84 metres). The added 1 m of storage would increase the long-term average hydro generation potential of the Yukon grid system by approximately 4 GW.h (the specific yearly benefit would depend on the overall load level and flow conditions throughout Yukon).

The MLESP was originally included as a component of the Mayo Hydro Enhancement Project (Mayo B) Proposal submitted in February 2009. During the 2009 adequacy review process, YESAB informed Yukon

Energy that the proposal was adequate with the exception of the Mayo Lake storage component. As a result, Yukon Energy made the decision to withdraw the Mayo Lake storage component from the Mayo B Project Proposal and file the Mayo Lake Enhanced Storage Project (MLESP) as a separate project at a later date. Yukon Energy subsequently completed a Project Agreement with FNNND regarding the Mayo B and Mayo Lake projects.

Following the Mayo B Part 3 hearing, the YUB (in its 2010 report to the Minister of Justice) recommended that Yukon Energy pursue the additional metre drawdown at Mayo Lake, noting positive effects that added draw down of Mayo Lake would have on the economics of Mayo B and associated positive impacts on rates. The present value of total project costs over the project life (i.e., the life of Mayo B project) were estimated at $5.4 million ($2012) (including mitigation and monitoring costs) with an LCOE of 6.3 cents/kW.h for approximately 4 GW.h/year of added average hydro grid energy with 1 m of added storage at Mayo Lake.

At the time of the 2012/13 GRA filing, Yukon Energy was in the final steps of preparing a submission to YESAB targeted for the end of 2012 for regulatory review of the project, and it was noted that the earliest potential MLESP project in-service was estimated to be during 2013. The GRA forecast $2.1 million going into rate base on or before the end of 2013. These costs were assumed to be amortized over the remaining term of the MGS water use licence (10 years at that time). In Order 2013-01, the Board approved the project as proposed in the GRA Application, noting that the amended water use licence would result in increased renewable power generation capability, would require no physical works, and would be amortized over the term of the MGS facility water use licence.

Between 2009 and 2014, Yukon Energy undertook additional fieldwork to fully address YESAB's July 2009 information requests related to the Mayo Lake project component. The additional fieldwork included bathymetry mapping and shoreline cross-sections in representative areas of shoreline types; benthic and aquatic plant surveys; lake trout and lake whitefish spawning studies; hydro-acoustic survey for sub-adult lake whitefish; lake whitefish rearing habitat studies; lake whitefish radio tagging; lake whitefish larval sampling; and Roop Lakes wetland health assessment (done by FNNND's technical advisor).

In addition to the biophysical studies, a public involvement program was initiated in 2011 to incorporate community input in the Project design, planning and environmental assessment. This included involvement with the FNNND, the Village of Mayo, the Mayo District Renewable Resources Council, residents of Mayo and surrounding area, various territorial and federal government departments, and other interested parties (i.e., fishers, trappers, placer miners). The public involvement program ran between February 2011 and October 2014.

As reported in the 2017/18 GRA, and as noted in the LNG Project Part 3 filings, ongoing studies indicated that sediments in the Mayo Lake outlet channel from over 50 years of operation would constrain water outflows through the channel at low lake levels, and dredging of the outlet channel would be required to restore capability and enable the Mayo Lake storage enhancement to proceed. It was determined that removal of the sediment deposits in the Mayo Lake outlet channel would be required in order to utilize additional storage at Mayo Lake as provided for in the proposed MLESP, and that a separate design, assessment and regulatory review process was required to remove these sediment deposits (with or without the MLESP) in order to restore the full hydro energy capacity at the Mayo hydro facilities, and to enable the opportunity to expand long-term average hydro energy ability to displace thermal generation through the extra storage proposed by the MLESP.

The MLESP YESAA Project Proposal was submitted to the Mayo DO in August 2015 (noting that a Mayo Outlet Dredging Project would be pursued separately in the future), with provision for the full one metre of added drawdown after an initial 0.5 metre drawdown and subject to adaptive management provisions that were co-developed, and would be implemented, with the FNNND. The DO suggested that review of the MLESP be grouped with an unrelated YG project – the Mayo River Flood Control Project on the lower Mayo River; and also required that the Mayo Lake Outlet Dredging Project be included in the MLESP review as an accessory project. In order to let the YG proposal move forward in a timely way, the Yukon Energy MLESP proposal was withdrawn, on the understanding that it would be resubmitted at a later time with additional information regarding the Mayo Lake Outlet Dredging Project.

Project spending during 2016 included environmental monitoring and Phase 1 of the dredging work, a desktop analysis. Environmental monitoring made up the majority of the 2017 costs and continued through 2018. Phase 2 of the dredging work, detailed modelling and design, was to take place during 2018. Once Phase 2 of the dredging work was complete, Yukon Energy was expected to have a much better estimate of the total costs to complete the project. At that point, a detailed economic analysis would be performed to re-evaluate the overall project benefit to ratepayers.

The deferred cost spending in WIP was forecast at $3.356 million by the end of 2018. Potential in-service for this project was 2022. In Board Order 2018-10, paragraph 513, the Board stated "The Board approved the Mayo Lake storage enhancement in Order 2013-01. Given that sediment removal is necessary to realize any benefits from this project, the Board considers that it is prudent to expand the scope of work for this project accordingly. Therefore, the Board approves the Mayo Lake storage enhancement project as applied for. The costs for this project are to remain in WIP, and the prudency of the costs will be assessed at the time the project is complete and YEC applies to add the costs to rate base."

As reported in the 2021 GRA, Northwest Hydraulic Consultants (NHC) was retained in 2018 to provide a technical assessment regarding whether sediment remediation steps in the Mayo Outlet Channel were feasible and cost effective. This assessment determined that removal of a coffer dam remnant in the outlet channel would improve flow in the near term and, through scouring activity, could potentially also remove the sediment from the channel; if required, as a next step, dredging the channel upstream of the coffer dam could improve hydraulic benefit for power generation. Yukon Energy subsequently proceeded with preparing a YESAA assessment for the project (including the two-phase outlet channel work) which was targeted to be filed with the Mayo DO before the end of 2020. The deferred costs forecast in the Application assumed that the project continues, with spending in WIP increasing from $3.373 million at the end of 2018 to $4.621 million by the end of 2021. Provided YWB licencing processes commenced in late 2020/early 2021, potential in service of the amended water use licence would be in 2023. Work to remove the coffer dam remnant would then proceed as a separate project.

The Board did not specifically address the project in Board Order 2022-03. In paragraph 337 the Board stated, "Given that the costs for the projects in this category do not affect the test year rate base or revenue requirement, the Board makes no findings regarding these projects at this time."

Project Update

In September 2020, following its initial charter approval in June 2019, the Yukon Energy Board approved a revised Stagegate budget of $667,000 to advance the MLESP to the submission of a YESAA Project Proposal to the DO. The draft YESAA Project Proposal was drafted in stages (i.e., by chapter) and provided to the FNNND for review over October through December 2020. After encountering significant delays through 2020 and early 2021, Yukon Energy paused all technical and assessment work. Stagegate 3 expenditures to the end of Q4 2021 were $923,000. Management communicated this budget overage of $256,000 to the Yukon Energy Board in early 2021 but had not requested a further increase in the Stagegate budget as spending had been halted.

In August 2021, Yukon Energy received a letter from FNNND indicating that recent events, such as low lake levels of Mayo Lake and increased cumulative impacts from upstream placer mining, are concerning. FNNND stated "Given what is now known about climate change and the cumulative effects of industrial development on the environment, FNNND government and our citizens have real concern about the Proposed Project's potential effects. FNNND well understands that low lake levels produce significant changes to the environment. These are concerns that are now understood and accepted widely throughout the Yukon." FNNND sought confirmation from Yukon Energy that it would not proceed with any regulatory submissions on the proposed project until FNNND agrees to it.

The scope of the project to be submitted in 2020 included:

- Phase 1 dredging (removal of the existing coffer dam remnants which impedes use of the current storage range);
- An amendment to the water licence (and obtaining a FAA), to lower the LSL by 50 to 100 centimeters; and
- Phase 2 dredging (active dredging to physically remove material out from the channel several years after Phase 1).

An economic analysis was conducted with updated assumptions to estimate the levelized cost of energy (LCOE) of two options:

1) Pursuing only the removal of the coffer dam, with no additional dredging or changes to the licensed LSL ($2 million in additional capital investment for ~1.7 GWh/year added long-term average [LTA] diesel displacement); and

2) Pursuing the entire scope of the MLESP, with removal of the coffer dam, physical dredging of the channel, and a lowering of the licensed LSL ($10.7 million in additional capital investment for ~4 GWh/year of LTA diesel displacement).

The results of this analysis indicate that both options are economic compared to thermal generation (including the incurred costs to date of $4.4 million). Option one provides almost half the energy benefit of the full project at a lower overall LCOE. No water use license amendment or FAA is required. It was also expected that this type of activity (removal of unused infrastructure) was unlikely to face as many social license challenges at this time. Costs of the MLESP in early 2022 were $4.603 million.

With this information on hand, Yukon Energy's Board of Directors decided that work to remove the cofferdam should be contemplated as part of the MGS Relicensing Project and costs associated with that work be transferred to the MGS Relicensing Project.

This approach also allowed for consideration of additional options, such as dredging and a change in the Mayo Lake LSL, in the future should they be appropriate and supported by the FNNND.

The costs transferred from MLESP to MGS Relicensing Project were assessed by Yukon Energy's Planning Department, and more specifically the Director, Risk & Compliance with assistance from the Regulatory Projects Financial Analyst. All costs of the MLESP were reviewed, regardless of amount.

Many of the transactions were allocable to either the MLESP or the MGS Relicensing Project.

MLESP costs related to the outlet channel dredging option assessments[11] are reasonably considered work undertaken to conduct an alternatives analysis regarding whether a storage range change should be pursued as part of the scope of relicensing (and are appropriately allocated to the MGS Relicensing Project). This work helped Yukon Energy to make an informed determination not to proceed with the dredging option; and provided the basis for Yukon Energy to conclude that it would not include any proposed storage range amendments in the MGS Relicensing Project scope.

Where costs were incurred that were considered beneficial to both projects, estimates of the amount of work relating to each project were made.[12]

Full costs of the MLESP by year, after transfer of applicable costs to the MGS Relicensing Project, are detailed in the table below. The total rate base impact is $2.267 million. The other $2.336 million of costs were transferred to the MGS Relicensing Project.

Table 5.2A-14: Mayo Lake Enhanced Storage Project Actual Costs (2012-2022) ($Million)

$ millions	2012-2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
Assessment	0.950	0.148	0.006	0.001	0.000	0.063	0.001	0.018	0.002	0.000	1.189
Project Management	0.085	0.029	0.017	0.004	0.000	0.001	0.000	0.000	0.002	0.003	0.140
Engagement	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.017	0.004	0.021
Third Party Engineering	0.123	0.139	0.138	0.000	0.000	0.058	0.000	0.000	0.000	0.000	0.458
Yukon Energy Internal Cost	0.117	0.081	-0.007	0.000	0.000	0.000	0.001	0.006	0.000	0.000	0.198
AFUDC	0.000	0.000	0.003	0.001	0.023	0.024	0.034	0.039	0.057	0.081	0.261
Total	**1.275**	**0.396**	**0.156**	**0.007**	**0.023**	**0.146**	**0.035**	**0.064**	**0.077**	**0.088**	**2.267**

- **Assessment**: Costs include conducting the environmental and socio-economic baseline studies to support assessment and permitting, development and First Nation/public engagement of the YESAA project proposal, completing development of mitigation, monitoring and adaptive management plans, and public and FNNND engagement costs.

[11] This included work completed by a contractor to develop an assessment of the need for the project, undertaken costs/benefits analysis and determine an approach to dredging.
[12] For example, it was determined that more than half of the work a consultant did yielded information that could support the assessment of potential effects of the ongoing operation of the MGS with the existing storage range. Therefore, only 60% of the costs were transferred to the MGS Relicensing Project.

- **Project Management**: Costs include internal labour representing staff leadership, participation, and support for activities in the preceding categories (i.e., project management, assessment, engagement and third-party engineering).

- **Engagement**: Costs include support from a legal consultant and support for negotiations with FNNND. The consultant(s) hired to assist with the assessment aided in the facilitation of the public and FNNND engagement; other engagement costs are reflected in the assessment category.

- **Third Party Engineering**: Costs include consultant costs related to the Mayo Lake outlet channel. They represent the examination of the outlet channel for capacity, determining the mechanisms for sediment recruitment and transport, a functional level design for dredging and dredgeate disposal, geophysical and bathymetric surveys, installation, maintenance, and operation of a meteorological station, and some components of the aquatic baseline program focused on the lake outlet species and habitats.

- **Yukon Energy Internal Costs**: Internal cost made up of travel, meal expenses, and venue rentals for public engagement events.

Project Justification

For regulatory purposes, Yukon Energy sees two possible accounting treatments going forward for the remaining MLESP costs of $2.267 million.

1) The MLESP costs could be kept in WIP until the remaining portion of the original project, the removal of the coffer dam, has been completed. The expected completion timing of this is uncertain. The effect of this is the project would continue to accrue AFUDC for several years, based on the time required for completion of the MGS water use licence and then construction for removal of the coffer dam.

2) Yukon Energy could transfer the $2.336 million of costs applicable to the MGS Relicensing Project to that project and close the MLESP. AFUDC on the Mayo Lake Storage project would cease when there was little-to-no probability it would offer a net economic benefit to ratepayers.

Yukon Energy believes the appropriate accounting treatment is alternative 2 (transfer coffer dam removal costs applicable now to the MGS Relicensing Project and close the MLESP) based on the YUB prior decision on the Southern Lakes Storage Project.

In Board Order 2024-05, paragraph 309, the Board states "Accordingly, the Board agrees with YEC that, notwithstanding the concerns it expressed in Board orders 2013-01 and 2018-10, the evidence shows that YEC continued to be actively and constructively engaged primarily through environmental assessments and public consultation with the affected parties until late 2022. The Board acknowledges that YEC continued to believe that there was a reasonable probability that the Southern Lakes project would proceed and acted in accordance with that belief."

Yukon Energy had reason to believe that there was a reasonable probability that the MLESP would proceed until February 2022; however, after receiving the letter from FNNND and assessing the options, Yukon Energy no longer had a reasonable basis for assuming that the MLESP components other than the coffer dam removal would likely be able to proceed at this time.

Based on this assessment, Yukon Energy has stopped AFUDC (and all other costs) on this project effective February 2022. This is also consistent with the Board's guidance and concerns in Board Order 2024-05 to minimize AFUDC costs.

Yukon Energy is submitting this redefined and cancelled MLESP as part of the 2025-2027 GRA based on guidance from the Board in the 2023/24 GRA relating to the Southern Lakes Storage Project. While Yukon Energy is now suggesting the project should be closed effective February 2022, Yukon Energy did not learn of the preferred treatment of the Board until its ruling in the 2023/24 GRA.[13] Yukon Energy's approach is also consistent with Board Order 2024-05 para 312 which states "in the case of cancelled projects, it should be clear to customers that the amounts that are included in rates are for cancelled projects. As there is no asset, YEC is to expense all costs for the project in the year the project is cancelled and reflect this change in YEC's capitalization policies and supporting documents." Based on this ruling, Yukon Energy is bringing it forward now, which is at the next opportunity for review.

[13] Yukon Energy could not have submitted the cancelled MLESP as part of 2023/24 compliance filing as it would have been new information that would not have been subject for full review by the Board and intervenors.

5.2A-5: INTEGRATED RESOURCE PLAN

Table 5.2A-15: Integrated Resource Plan Costs in Rate Base

Opening WIP	2025	2026	2027	Total Additions
$581,600	$750,000	$1,000,000	$0	$2,331,600

Project Description

The Integrated Resource Plan will identify generation resources that are needed to allow Yukon Energy to deliver reliable, affordable, and sustainable electricity to Yukoners over the next twenty years. It will address broad questions of how much, where, when, and what new electricity supply and transmission resources should be advanced to meet customer electricity needs in the near term. Yukon Development Corporation will be leading longer-term Integrated Resource Planning for the Yukon.

The goal of the project is to develop a System Resource Plan that is actionable and likely to be implemented. Project tasks include the following:

- Complete a Resource Plan – Short-Term Actions (STAP) to identify generation resources needed in the next ten-years that require immediate resources and can be implemented in the immediate term;
- Complete a 20-year load forecast considering the drivers that influence electricity consumption;
- Update and assess electricity supply resource options that could practically be expected to meet forecasted demand;
- Develop base and contingency resource plans identifying generic regional resource options to meet forecasted load;
- Communicate findings in an external facing System Resource Plan report; and
- Establish sufficient basis for a "Call for Power" for sources of intermittent renewable generation under the leadership of the Yukon Development Corporation.

Resource planning work began in 2024 with development of a Resource Plan – Short-Term Actions (STAP) which identified the electricity needs of Yukoners for the next 10 years and the generation resources needed near Whitehorse, Yukon's largest and fastest growing load centre, to meet these needs. Actions identified in the STAP contributed to the development of our Strategic Plan and Chapter 1. Work completed in 2024 and 2025 to support the System Resource Plan included the following:

1. Developing the STAP;
2. Developing inputs for the System Resource Plan;
    a. Conducting a load forecast;
    b. Conducting a Loss of Load Expectation study (LOLE); and
    c. Conducting a Resource Adequacy Study.

Going forward, the System Resource Plan activities include updating generation resource options, conducting desktop modeling to analyze the ability of generation resources to meet the Yukon's electricity needs over the timeline, reporting, and supporting Yukon Development Corporation with a Call For Power to develop distributed renewable energy resources across the territory.

Overall, this project will develop a plan that identifies feasible and cost-effective generation resources needed in the Southern and Northern Regions of Yukon to meet electricity needs of our customers. Project forecast costs of $2.332 million will be amortized over a 10-year period following completion of the System Resource Plan.

Project Justification

Resource plans are tools that electrical utilities use to articulate long-term strategic vision, identify priorities, manage uncertainty in a changing environment, and identify shorter-term action plans. Yukon Energy last completed a Resource Plan in 2016, followed by in 2020 the Ten-Year Electricity Renewable Plan. Though several projects identified in this plan advanced, key projects to provide winter dispatchable capacity did not (i.e. Atlin Hydro, Moon Lake Pump Storage). The Yukon's demand for electricity on the coldest day of the year has outpaced what can be supplied by our permanent resources alone and in 2017, Yukon Energy began renting diesel generators for winter capacity. The need for new generation is driving the development of this System Resource Plan.

Resource planning by a utility supports:

- **Long-Term Capacity and Energy Planning:** A resource plan helps utilities forecast and plan for future electricity demand over a specified period, ensuring they can meet customer needs reliably.

- **Cost-Effectiveness:** By evaluating a wide range of supply-side and demand-side resources, a resource plan identifies the most cost-effective mix of resources to meet future demand. This includes new generating capacity, power purchases, energy conservation, and renewable energy sources.

- **Risk Management:** By considering various scenarios and uncertainties, a resource plan helps utilities manage risks related to fuel prices, load growth, and regulatory changes. This ensures a robust and adaptable plan that can withstand future challenges.

Project Context

A global energy transition is underway, trending towards decarbonization and increased electrification, distributed energy resources, and grid modernization. Like other jurisdictions across Canada, Yukon Energy has observed the impacts of electrification and increases in demand: peak demands have increased by 25% between 2014-2024, and are forecasted to increase by 40% between 2020-2030.

Yukon Energy has prepared resource plans regularly since 2006 to address generation and transmission priorities in Yukon for 20-year planning horizons. Resource plans have been submitted to the YUB as a standalone proceeding (2006) or as part of GRA proceedings (2011, 2016).

Though there is currently no regulatory requirement for Yukon Energy to prepare a resource plan, resource plans are considered best practice amongst utilities across North America. In 2007, the YUB recommended that Yukon Energy update the resource plan every five years; however, in 2018, the YUB stated that time frame is no longer recommended due to the significant expense incurred with the 2016 Resource Plan compared with earlier Resource Plans. The scope, thoroughness, and cost of the 2020 10-Year Renewable Electricity Plan were significantly reduced from the 2016 Resource Plan.

Some of the renewable and thermal projects identified in the 2016 and/or 2020 plans have not progressed, and Yukon Energy has experienced ongoing winter electricity dependable capacity deficits necessitating rental of diesel generation units. The reason projects have not advanced vary and include First Nation opposition, lack of social license, Yukon Energy Board decision to adjust thermal project plans, and federal funding gaps in response to escalating renewable project costs.

The existing dependable capacity gap is driving the need to undertake a new resource planning process. The System Resource Plan will consider how Yukon Energy identifies resource options and informs longer-term capacity planning ultimately leading to more successful project implementation.

Project Schedule and Budget

Project planning and spending began in 2023. In the 2023/24 GRA, Yukon Energy showed a forecast of $2.000 million in work-in-progress at the end of 2024. In the 2025-2027 GRA, Yukon Energy is forecasting total costs of $2.332 million.

In 2024, Yukon Energy revised the scope to incorporate development of a Resource Plan - Short-term Actions (Short-term Action Plan) and engagement activities with First Nations partners. The Short-term Action Plan forms the first phase in the resource planning process, which identifies the electricity needs of Yukoners for the next 10-years and Yukon Energy's plan for new generation resources to meet these needs. The schedule shifted into 2026 from 2024 to allow for development of the Short-term Action Plan in 2024-2025, followed by a System Resource Plan in 2025-2026. Yukon Development Corporation will be leading long-term generation planning through an Integrated Resource Planning process.

In late 2023, Yukon Energy began sharing the Short-Term Action Planning process with First Nation and Yukon governments, followed by broader engagement. In early 2025, Yukon Energy shared the Short-Term Action with First Nations across the territory followed by more general engagement with the territorial government and municipalities. The Yukon Development Corporation will lead further engagement about energy planning, First Nation investment opportunities in the energy sector and the potential transmission connection between BC and the Yukon.

The project schedule is provided in the Table below.

Table 5.2A-16: Integrated Resource Plan Activities and Timeline

Task	High-Level Activities	Timeline
1. Input Development	• Load forecasting • Resource adequacy	Q2 2025
2. Scenario Design	• Determine what potential futures to evaluate in the planning process	Q3 2025
3. Development and Updating of Resource Options	• Update or develop resource options	Q4 2025
4. Modeling	• Desktop modeling (CAPEX) to determine resource portfolio recommendations for multiple scenarios	Q1 2026
5. Develop System Resource Plan	• Evaluate resource portfolio recommendations and determine themes • Develop base resource plan and contingency resource plans • Develop short-term actions	Q2 2026
6. Reporting	• Develop final System Resource Plan reports • Communicate outcomes	Q3 2026
7. Call For Power	• Support YDC with scoping and execution of a Call for Power for intermittent renewables	Q4 2026

The Project team is primarily Yukon Energy staff, with external contractor support expected for select technical deliverables. Full forecast costs of the project are detailed in the table below.

Table 5.2A-17: Integrated Resource Plan Forecast Costs

Item	Cost ($million)
Short-term Action Plan	$0.342
Project Management	$0.355
Data Development	$0.722
Engagement	$0.050
Resource Options	$0.226
Reporting	$0.300
Call For Power Support	$0.080
AFUDC	$0.057
Contingency	$0.200
Total	**$2.332**

APPENDIX 5.2B
DEFERRED PROJECTS >$400,000 AND UP TO $2 MILLION ADDED TO RATE BASE

APPENDIX 5.2B: DEFERRED PROJECTS >$400,000 AND UP TO $2 MILLION ADDED TO RATE BASE

5.2B-1: AGS 5-YEAR FISHERIES ACT AUTHORIZATION

Table 5.2B-1: AGS 5-Year Fisheries Act Authorization Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$714,200	$0	$0	$0	$714,200

Project Description

The overall objectives of the Aishihik Generating Station (AGS) License Renewal Project is to secure approvals for a water use licence (WUL) and *Fisheries Act* Authorization (FAA). A 3-year WUL and a 3-year FAA expired at the end of 2022. On December 20, 2022, Yukon Energy renewed the AGS Water Use Licence for a 5-year period. A short-term (one-year) FAA extension was also issued on December 31, 2022, and further short-term FAA extensions have been obtained since 2022 to ensure that the existing FAA does not expire while the 5-year FAA renewal process is being completed. The 5-year FAA renewal process will ensure that activites that require an FAA are authorized to the end of 2027.

The AGS 5-Year FAA project (the Project) is is focused on completion of the AGS FAA 5-year renewal (from the end of 2022 to the end of 2027). The FAA application aligns closely with the WUL application in many respects, but with a more narrow focus related to regulating AGS activities in the context of fish and fish habitat.

The FAA extension process to date is detailed below:

- In Q3 2022, the Department of Fisheries and Oceans (DFO) indicated to Yukon Energy that the 5-year renewal process for the existing FAA would extend into 2023. This resulted in Yukon Energy submitting a request for a short-term status quo extension of the existing FAA. After consultation with YG and CAFN, this was issued near the end of December 2022. This schedule shift did not require a project scope or budget change.

- A 5-year FAA is required to bridge to the next relicensing at the end of 2027. Costs associated with the FAA application include related technical advisory, permitting support and analytical tasks.

- Subsequent to the completion of the 5-Year AGS WUL renewal, Yukon Energy continued collaboration with CAFN and YG to address DFO's questions on the FAA renewal application. Yukon Energy provided a response to DFO's FAA application adequacy review during Q3 2023. DFO replied later in Q3 2023 with clarifications regarding what it needed to consider the FAA application complete. Yukon Energy, YG, and CAFN then met with DFO in September 2023 to review the response. The outcomes of this meeting with the regulator included Yukon Energy providing a near-term work plan to address the outstanding information requirements and an agreement for the Corporation to apply for a short-term FAA extension through to June 2024 to allow for the review of the FAA renewal application to be completed. CAFN and YG were in support of this short-term extension. With agreement from CAFN and YG, Yukon Energy submitted a request for a short-term status quo extension of the FAA through 2024. The FAA extension was subsequently issued by DFO in December 2023.

- The Parties developed a collaboratiave work plan for completion of the FAA renewal in 2024. Regular and structured consultations with YG and CAFN occurred throughout the FAA process. However additional time was deemed necessary to collect specific information, conduct analyses, and consult with CAFN and YG before the information DFO required to deem the FAA application complete could be submitted. In collaboration with CAFN and YG, Yukon Energy prepared a revised work plan to provide suitable information to DFO to deem the FAA renewal application complete. Yukon Energy requested an extension to the FAA renewal process based on revised workplan schedule. DFO has confirmed acceptability of this revised workplan.

- The current work plan schedule to renew the FAA has been extended with agreement from CAFN and YG. The Yukon Energy technical team worked through the data collection and analysis requested by DFO to deem the FAA renewal application complete and Yukon Energy completed analysis and consultations with YG and CAFN necessary to submit a complete application to DFO for the FAA renewal. Yukon Energy submitted its response to DFO's FAA application information request in February 2025. The remaining process schedule is projected to extend through July 15, 2025. This time will be used by DFO to conclude the application review process and required consultations with CAFN and YG.

Change from 2023/24 GRA

As fully described in the AGS License Renewal Project report in Appendix 5.2A, Yukon Energy costs of $4,708,000 for the overall five-year AGS licence renewal were reviewed and approved by the YUB during the 2023/24 GRA. This included costs related to the FAA renewal.

However, as per above, the FAA was not completed by the end of 2022. Therefore, the final approved 2023/24 GRA enabled Yukon Energy only to add $3.903 million of 5-Year Licence Renewal costs to its ratebase in 2022. Yukon Energy forecast completion of the FAA renewal process in 2024 at a cost of $0.804 million. The FAA renewal process was not complete by the end of 2024 and was not included in rate base.

For the 2025-2027 GRA, Yukon Energy is forecasting completion of the FAA 5-year renewal (2023-2027) in 2025 at a cost of $0.714 million. It is also noted that some of the forecast $0.650 million AGS 25-year licence renewal costs in 2025 may be attributable to the completion of the AGS 5-Year FAA renewal.

5.2B-2: DEMAND SIDE MANAGEMENT

Table 5.2B-2: Demand Side Management Costs Added to Rate Base

Opening WIP	2025	2026	2027	Total Additions
$0	$747,000	$484,000	$444,000	$1,675,000

Project Description

The Demand Side Management (DSM) program introduced in the 2023/24 GRA will continue during the 2025-27 GRA test years, seeking to mitigate peak demand contributions from homes, electric vehicle charging, and local commercial and institutional entities and thereby reduce requirements for new dependable capacity development and/or diesel rentals. DSM costs continue to be amortized over 10 years.

Background

In Yukon Energy's 2023/24 General Rate Application, the DSM Program Development and DSM Program 2022-2030 were introduced, with costs for 2023 and 2024 submitted for review and approval. In Board Order 2024-05, the Board's findings were provided in paragraph 291: "*Having examined YEC's information and submissions with respect to the Phase I portion of its DSM program, the Board finds that the rationale for the activities and related costs is persuasive. Consequently, the Board finds these costs to be reasonable and they are approved*."

Yukon government OIC 2021/16 specifies the following three requirements for DSM costs to be recovered through rates:

1. Costs must meet the definition of "demand-side management' program;
2. Costs must be "reasonably incurred"; and
3. Costs must not be duplicative of DSM programs participated in or provide by another Yukon public utility or the Yukon Government.

DSM Spending in 2025 through 2027

The DSM costs forecast for 2025 through 2027, applicable to the current GRA test years, are a continuation of the costs introduced in the DSM Program 2022-2030. A summary of the costs by program and by year are in the table below.

Table 5.2B-3: Summary of DSM Program 2022-2030 Costs by Program and By Year

Items ($000's)	2025	2026	2027	Total
Internal Yukon Energy Labour	$95	$100	$100	$295
Peak Smart Home	$203	$106	$83	$395
Peak Smart Drive	$158	$120	$113	$391
Peak Smart Work	$176	$116	$118	$410
Contingency	$115	$42	$30	$187
TOTAL	**$747**	**$484**	**$444**	**$1,675**
Expected Dependable Capacity (kW)	250	350	500	

OIC 2021-16 Requirement #1: Meet the Definition of "Demand-Side Management Program"

In Yukon Energy's 2023/24 GRA, it was shown that Yukon Energy's DSM portfolio met the definition of DSM through direct customer participation and improving alignment with electricity supply and demand. As forecast DSM spending in the 2025-2027 test years is consistent with DSM Program 2022-2030, Yukon Energy considers these costs to have already been determined to meet the required OIC definition.

OIC 2021-16 Requirement #2: Costs Must Be "Reasonably Incurred"

In Yukon Energy's 2023/24 GRA, a comprehensive review of DSM cost-effectiveness tests was conducted and analyzed, specifically the Utility Cost Test (UCT), Total Resource Cost (TRC), Societal Cost Test (SCT) and Rate Impact Measures Test (RIM). The analysis noted the limitations of the RIM test and that "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 analysis also noted that "the Utility Cost Test is most reflective of 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."

Yukon Energy's 2023/24 GRA concluded that the business case assessment 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.

As forecast DSM spending in the 2025-27 test years is consistent with the DSM Program 2022-2030, Yukon Energy considers these costs to have already been determined to be reasonably incurred.

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

In Yukon Energy's 2023/24 GRA provided a comprehensive comparison of DSM and related programs offered by various territorial government departments, Crown corporations and utilities. From that comparison, it was clear that there was 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 of these entities were in regular communication to support each other's energy and climate-related initiatives such as through the Advisory Group on Energy Demand and Supply (AGEDS)[1] and the DSM Working Group[2].

Ongoing and regular communication through continuation of the AGEDS and DSM Working Group helps to ensure that no DSM program duplication occurs. Yukon Energy has also obtained an updated signed statement from the relevant parties that the planned spending in 2025 through 2027 by each party is not duplicative. See Attachment 5.2B-1: DSM Program Comparison.

Conclusion

The above updated assessment has demonstrated that the current and planned Yukon Energy DSM programs that affect rate base costs in the 2025-2027 test years meet all three requirements stipulated by OIC 2021-16:

[1] The purpose of AGEDS is to provide a platform for Yukon government and Yukon's public utilities to identify, collaborate and advance the initiatives needed to build a reliable and resilient electricity system that is equipped to support policy objectives and provides Yukoners with safe, sustainable, reliable and affordable electricity.
[2] Engineers/Management from Yukon Energy/YG/AEY discuss opportunities for DSM and overall Demand Response.

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 RIM test and UCT test, 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 demonstrates 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.

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.

ATTACHMENT 5.2B-1: DSM PROGRAM COMPARISON

Attachment 1 – Yukon DSM Program Comparison

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 five 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 and contests.

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 the GRA test years of 2025-2027, as of February 1, 2025. The contents of Table 1 are confirmed by representative of each entity on the signatory page that follows.

Update – January 2025:

In April 2024, Yukon Energy closed public registration for its residential direct-install "Peak Smart Home" program, effectively ceasing the provision of capital incentives by Yukon Energy to the public for its DSM programs. The program was re-launched in December 2024 using a "Bring Your Own Device" (BYOD) delivery model. Under this program delivery model, participants are responsible for the purchase, installation, and enroll eligible devices.

To encourage program participation and reduce financial barriers to participate, the Yukon Government Energy Branch introduced a series of publicly available capital rebates for smart thermostats and hot water tank controllers compatible with the Peak Smart Home program in December 2024. These rebates include higher amounts for applicants who demonstrate enrollment in the program.

With the Yukon Government offering capital incentives to drive initial enrollments in the Peak Smart Home program, Yukon Energy has planned to issue on-going participation incentives to reward active participant engagement and reduce participation attrition. The first such incentive is the "Peak Smart contest," offering $5,000 in prizes to be drawn in spring 2025. This contest has been announced as a one-time initiative, with no guarantee of future iterations. External funding specifically intended for DSM program incentives has been secured, covering at least the cost of this participation contest.

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 (AEY)
Residential Buildings					
Capital Incentives:	None.	Rebates for various energy-saving technologies and upgrades, including smart thermostats and hot water tank controllers, subject to eligibility criteria set by Yukon Government.	None.	None. Development of or participation in any demand response programs by YHC would be conducted in coordination with Yukon Energy to prevent program duplication.	None. Development of or participation in any demand response programs by AEY would be conducted in coordination with Yukon Energy to prevent program duplication.
On-Going Incentives:	Current: Externally funded annual contest for participants. Planned: Externally funded annual on-bill credits for eligible program participants, starting in 2026.	None.			
Commercial / Institutional					
Capital Incentives:	None.	Capital funding for various energy saving technologies and upgrades, including smart thermostats, and electric vehicle chargers, subject to eligibility criteria set by Yukon Government.	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.	None.	See comments above.
On-Going Incentives:	Planned: Externally funded on-bill credits and annual participant contest as on-going incentives for participants in our commercial and community demand response program (~2025/26).	None.	None.	None.	See comments above.
Transportation					
Capital Incentives:	None.	Rebates for electric vehicles and electric vehicle charging systems, subject to eligibility criteria set by Yukon Government.	None.	None.	See comments above.
On-Going Incentives:	Current: None. Planned: Externally funded on-bill credits and annual participant contest for our electric vehicle 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 any document this report is appended to.

Yukon Government – Energy Branch

Signatory Name: Amanda MacDonald

Position: Director, Business Transforr

Signature: Amanda MacDonald
Amanda MacDonald (Mar 3, 2025 13:45 MST)

Date: 03/03/25

Yukon Housing Corporation

Signatory Name: Eric Gaucher

Position: Project Manager

Signature: Eric Gaucher

Date: 25/02/25

Yukon Government – Highways & Public Works

Signatory Name: Shane Andre

Position: Director, Energy Branch

Signature: Shane Andre
Shane Andre (Feb 7, 2025 14:15 MST)

Date: 04/02/25

ATCO Electric Yukon

Signatory Name: Tony Badry

Position: Tony Badry

Signature: Tony Badry
Tony Badry (Feb 13, 2025 07:13 MST)

Date: 13/02/25

Yukon Energy Corporation

Signatory Name: Michael Muller

Position: Vice President

Signature:

Date: 10/02/25

APPENDIX 5.3
FX-001 CRITERIA FOR CAPITALIZATION

YUKON ENERGY	Finance Accounting Practice **FX-001**	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Finance	Criteria for Capitalization
		ISSUED:	REVIEW DATE:	APPROVED BY:
		January 1, 2025	December 31, 2027	Chief Financial Officer

1.0 Purpose

To provide guidelines for determining whether expenditures should be capitalized or expensed. Primary source used is IAS 16 Property Plant and Equipment and industry guidance (BC Hydro).

2.0 Recognition

The cost of an item of property plant and equipment shall be recognized as an asset if, and only if:

a) It is probable that future economic benefits associated with the item will flow to the entity; and
b) The cost of the item can be reliably measured.

Items of property, plant and equipment may be acquired for safety or environmental reasons. The acquisition of such property, plant and equipment, although not directly increasing the future economic benefits of any particular existing item of property, plant and equipment, may be necessary for an entity to obtain the future economic benefits from its other assets. Such items of property, plant and equipment qualify for recognition as assets because they enable an entity to derive future economic benefits from related assets in excess of what could be derived had those items not been acquired (IAS 16, para 11).

Based on industry guidance[1], Yukon Energy has established an annual project expense (Operations & Maintenance) budget that is used to fund projects in very early stages. Yukon Energy has in essence adopted this policy as Capital Project Studies or CPS, resulting in the expensing of costs that do not meet the capitalization criteria.

[1] BC Hydro established an annual project Operating and Maintenance budget that is used to fund projects in very early phases (Capital Projects Investigations or CPI) or to cover non-capitalizable costs (design of a new type of equipment). BC Hydro releases a project with "seed" money or CPI to allow the project teams to identify the alternatives and determine the leading alternative. Until a leading alternative is identified, capitalization criteria have not been met so the project continues to be funded from CPI.

3.0 Criteria for Capitalization

Notwithstanding clause 2.0, expenditures are considered capital in nature if one or more of the following criteria are met:

a) If they have been incurred to acquire, construct, or develop assets that will be used on a continuing basis for longer than one year.
b) The resulting asset will be held for use in the generation, transmission, or distribution of electricity, directly or indirectly.
c) The cost is significant relative to the total capital cost of the particular asset. In the case of new assets, the cost must exceed $1,000.

Additional guidance on determination of capitalization as opposed to expense is as follows:

Phase	Key Objectives	Classification
Identification Phase (Needs Stage)	• Conceptual design • Confirm project scope and schedule • Identify potential alternatives • Confirm project team resourcing and accountabilities	O&M (CPS)
Identification Phase (Conceptual Design Stage)	• Analyze agreed conceptual alternatives • Identify leading alternative to move into Feasibility Desing stage • Ensure capitalization requirements are met before moving into Feasibility Design Stage	O&M (CPS)
Identification Phase (Feasibility Design Stage)	• Additional design work on leading alternative to provide more refined cost estimate and reinforce leading alternative • Identify the preferred alternative	Capital
Definition Phase	• Define the preferred alternative sufficiently to finalize the business case and project plan	Capital
Definition Phase with Partial Implementation Phase costs (not including construction)	• Initiate procurement process for long-lead time equipment • Initiate design work	Capital
Partial Implementation Phase costs including construction	• Start some construction activities prior to requesting full funding approval	Capital
Implementation Phase	• Complete detailed design • Procurement • Start construction • Complete commissioning and acceptance work	Capital

Acquisition Costs for capitalization include, but are not limited to:

a. original purchase cost of the asset
b. engineering costs
c. material, supplies
d. consulting, contractor fees
e. freight, brokerage, duty
f. labour, including the cost of benefits
g. vehicle operating costs
h. travel costs
i. equipment rentals
j. project insurance
k. professional fees (legal costs)
l. brokers' commissions
m. installation costs
n. site preparation costs
o. incremental costs related to power supply to customers during construction or installation of a new asset
p. costs of testing whether the asset is functioning properly
q. warranties purchased with initial purchase or during project construction
r. Allowance for Funds Used During Construction (AFUDC costs)
s. the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period. (IAS 16, para 16(c))

The Corporation capitalizes revenue generating meters, regardless of the cost of each meter.

The Corporation capitalizes streetlights, regardless of the cost of each streetlight.

The Corporation capitalizes transformers and breakers, regardless of the cost of each transformer and breaker.

4.0 Subsequent Costs

4.1 Replacement of Existing Assets

Parts of some items of property, plant and equipment may require replacement at regular intervals. For example, the headgate of a dam may require replacement. Under the recognition principle, an entity recognizes in the carrying amount of an item of property, plant, and equipment the cost of replacing part of such an item when that cost is incurred if the recognition criteria in 2.0 are met. The carrying amount of those parts that are replaced is derecognised (ref: IAS 16, para 13).

4.2 Overhauls/Inspections/Certifications (ref: IAS 16, para 14)

A condition of continuing to operate an item of property, plant and equipment (for example, a hydro unit or thermal engine) may be performing regular major inspections for faults regardless of whether parts of the item are replaced. When each major inspection is performed, its cost is recognised in the carrying amount of the item of property, plant and equipment as a replacement if the recognition criteria are satisfied. Any remaining carrying amount of the cost of the previous inspection (as distinct from physical parts) is derecognised.

Major overhauls are considered capital as they extend the useful life of existing assets. They are recorded as a fixed asset, pooled with the current asset base and depreciated at the same rate as the pooled assets to which they belong.

Minor overhauls are considered maintenance in that they ensure the efficient operation of an existing unit; they are expensed in the period in which they occur.

4.2(a) Diesel Units

Minor Overhauls are sometimes referred to as top end overhauls, most often involving the reconditioning of the cylinder head assembly, but could also include work on external components such as water pumps, coolers, turbochargers, etc. Minor overhauls are expensed.

Major Overhauls typically involve the tasks of minor overhauls, plus additional work involving the disassembly of the crankshaft, and work on connecting rods, liners, main bearings, main oil pumps, etc. A major diesel overhaul is capitalized and is typically performed every five years, depending on actual hours used.

4.2(b) Hydro Units

Minor Overhauls are often viewed as annual inspections (PM's) as they involve minimal disassembly. They typically involve activities such as vibration checks, checks on bearings, checks of governor and related equipment, underside inspections, unit inspections, and general visual inspections, etc. Minor overhauls are expensed.

Major Overhauls involve the disassembly of the unit and work on major components such as bearings, wicket gates and turbine runners. Hydro production units typically have a major overhaul once every 10 years. A major hydro overhaul is capitalized.

4.2(c) Gas Units

Minor Overhauls are recommended after every 2,000 hours of run time. This type of overhaul consists of work on the ignition, transmission, and gas pressure control system. These are treated as maintenance and expensed in the year of occurrence.

Major Overhauls are completed after 10,000 hours, 20,000 hours, 30,000 hours, and 50,000 hours. These types of overhauls involve work on the pre-combustion chamber, the starter, cylinder head replacements, pre-lubrication pump, crankshaft thrust bearing, exhaust-gas turbocharger, engine cooling pump, gas quantity controller, mixture bypass valve, vibration damper, pressure regulator, pistons, engine oil pump, connecting rods, cylinder liner, crankshaft bearing, camshaft and control system. A major hydro overhaul is capitalized.

4.3 Betterments, Improvements, Uprates, or Refurbishments to Existing Assets

In accordance with 2.0 (future economic benefits will flow to YEC), Betterments, Improvements, Uprates or Refurbishments must meet one of the following criteria to be capitalized:

a) Increase the service life of the existing asset.
b) Reliability and/or quality improvements above original design standards.
c) Increase the previously assessed physical output or service capacity.
d) Reduce operating costs of the existing asset by a substantial and quantifiable amount.

5.0 Intangible Assets

An intangible asset is an identifiable non-monetary asset without physical substance. It is required to be identifiable, must have control over a resource and there must be existence of future economic benefits. Examples of intangible assets could (but not necessarily) include design and implementation of new processes or systems, licenses, and computer software, etc. (ref: IAS 38 par 8-17).

6.0 Regulatory and Licensing Projects

When the project is driven by a regulatory requirement, all the related project costs should be capitalized. When the project is completed (for example, new license) and it results in ongoing obligations (such as monitoring), these ongoing costs are not considered capital.

7.0 Capital Leases (Right-of-Use Assets)

The cost of an item of property, plant and equipment may include costs incurred relating to leases of assets that are used to construct, add to, replace part of or service an item of property, plant and equipment, such as depreciation of right-of-use assets (ref: IAS 16, para 10).

8.0 Critical Spares

Items such as spare parts, stand-by equipment and servicing equipment are recognized in accordance with this IFRS when they meet the definition of property, plant and equipment (ref: IAS 16, para 8). In order to be defined a critical spare, the item must meet all the following criteria:

- The item is unique to the asset it supports (substitutes are not available and/or cannot be readily fabricated),
- The absence of this item would cause a significant loss of asset service availability or have a significant negative impact on safety, environment or regulatory requirements,
- The item has a long lead time for procurement, and
- There is an expectation of use of the item for more than one period.

Common examples of critical spares may include certain transformation equipment for key substations, and parts for hydro generators. Non-critical spare parts are included in inventory.

9.0 Non allowable costs

Examples of costs that are not costs of property, plant and equipment are:

a) Costs of staff training
b) Administration and other general overhead costs
c) Operating Leases
d) Costs of the day-to-day servicing of the item. Costs of day-to-day servicing are primarily the costs of labour and consumables and may include the cost of small parts.
e) Maintenance and repair costs are not capital improvements and are expensed in the period incurred, regardless of whether the cost exceeds the capitalization threshold. Maintenance is the work required to preserve and maintain the asset to perform its designated function for its establish life, Repairs are activities that allow PP&E to attain its original useful life.

10.0 Project Cancellation

When it is determined that a project in progress is no longer viable, the project should be closed and all costs expensed at that time. A regulatory deferral account may be requested from the

Yukon Utilities Board for amortization over a longer period for the purposes of income and rate smoothing.

11.0 Depreciation

Assets are depreciated based on the estimated useful life of the assigned asset class as per the 'GP Users Manual for Property Plant and Equipment'. Estimated useful lives are re-evaluated as required via a third-party depreciation study.

APPENDIX 5.4A
CAPITAL PROJECT >$400,000 REMAINING IN WIP

APPENDIX 5.4A: CAPITAL PROJECT >$400,000 REMAINING IN WIP

5.4A-1: WHITEHORSE POWER EXPANSION

Table 5.4A-1: Whitehorse Power Expansion Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$200,200	$1,500,000	$2,500,000	$50,000,000	$54,200,200

Project Description

The Whitehorse Power Expansion Project will increase system reliability by providing dependable capacity needed to meet peak demands for electricity in wintertime and upgrading transmission and substation infrastructure to reliably deliver electricity to our customers near Whitehorse. This project will bring capacity and transmission resources to Yukon’s major load centre of Whitehorse and enable the replacement of diesel rentals in Whitehorse.

The project and its associated infrastructure (new firm winter capacity generation, and new and upgraded transmission and substation assets) are essential for Yukon Energy to advance its strategic priorities of providing Yukoners with adequate and dependable supplies of electricity and strengthening the electricity system. When complete in the next-five years, the project will support a resilient and reliable electricity grid, provide the foundation for a more modern and flexible grid in the Whitehorse area ready to accommodate urban needs, and support the safe connection of more community-based renewables in the future.

The primary objectives of the Whitehorse Power Expansion Project are as follows:

1. Construct the required winter thermal generation resources near Whitehorse to meet winter capacity needs between 2025 and 2030;

2. Construct the system transformation and transmission needs near Whitehorse to improve reliability of electricity delivery to our customers; and

3. Construct the required winter thermal generation resources near Whitehorse to meet capacity needs through 2035 in a way that provides flexibility to add additional capacity, if required, or the removal of thermal generation from the site as new firm sources of renewable electricity are built or connected to the grid.

The scope of the Whitehorse Power Expansion Project includes the following specific near-term (2030) thermal facility plans (contingent in each case upon actual load growth projections as they evolve and shift, permitting timelines, procurement outcomes, and construction timelines):

1. In 2026-27, build a diesel site in south Whitehorse to accept up to 15 MW of diesel generation.[1] In the immediate term (0-3 years), diesel rentals will be added to the site to meet load growth until the larger site in the north of Whitehorse is brought in-service.

2. In 2028-29, build a thermal site in north Whitehorse with the first phase (30-45 MW) of generation, upgrading and building new substations and transmission line assets needed for plant connection to the grid.

3. In 2029-2030, installing the second phase (additional 15-30 MW) of generation at the thermal site in north Whitehorse; completing additional transmission and substation upgrades as needed (the planning will also provide for potential added thermal capacity at this site, as needed, by 2035).

4. In 2030, upgrade the South Whitehorse site with up to 15 MW of permanent thermal generation, replacing any rentals on site.

Bridging the gap to 2030 is Yukon Energy's biggest challenge and top priority. Peak demands for electricity are growing every year and Yukon Energy forecasts a need for additional generating capacity (i.e., more diesel rentals) in winter 2026/27. In the immediate-term, winter capacity needs in Whitehorse will continue to be met through mobile diesel rental generators. Two key actions are identified to bridge the gap to 2030:

1. In 2025, focus on optimizing operation of existing assets (owned and rented) and invest in transmission upgrades to reinforce system reliability and available generation in winter 2025/26.

2. Build a new thermal generation site in the south of Whitehorse, if possible, by winter 2026/27, to add more diesel rentals until such time that those units can be replaced by more permanent units.

Permitting and licensing timelines prohibit a new diesel site being commissioned before winter 2025/26. With this context, in 2025 Yukon Energy's key priorities will be to commission firm capacity projects currently under construction (thermal replacement, battery); make upgrades to existing thermal sites to

[1] Due to uncertainty of costs and timing of completion, this GRA Application does not include in test year rate base this project's costs for the new South site 15 MW diesel facility planned for completion before the end of 2027. This construction is contingent upon actual load growth and shifts in load growth projections, permitting timelines, procurement outcomes and construction timelines. Updates will be provided as available during the current GRA procedure.

increase output of existing capacity on site; harden the existing transmission connection between the north and south grid to increase availability of power supply in the north for use in the south; and improve the reliability of the existing rental fleet.

This project is only addressing electricity needs in what is being called the Southern Region (south of Carmacks). More planning is needed to define long-term capacity needs and options in the Northern Region. Based on current information, an additional 10 MW of new thermal capacity may be needed in the Northern Region if all rentals were removed. However, ongoing planning will review and address Northern Region requirements in light of evolving information.

Why do this project now?

Urgent investment in firm winter capacity and new transmission infrastructure near Whitehorse (i.e., The Whitehorse Power Expansion) is needed for three key reasons:

- **Demand will soon exceed supply.** In the next five years, Yukon homes and businesses connected to the Yukon grid will demand more electricity during the winter than is available from Yukon Energy's generation assets. This is primarily due to population growth and the incentives driving increased electric heat and vehicle use. In winter 2024/25, Yukon Energy rented 22 diesel engines to help meet YIS winter capacity needs according to Yukon Energy's N-1 dependable capacity planning criteria. By 2030, the forecast number of rental diesels required will increase from 22 to over 30. While continuing to rent more diesel generators is the only viable solution to meet peak demands for power in the near-term, diesel rentals are not a long-term solution as they are less reliable than permanent diesel generators and do not meet our vision for a reliable and clean energy system.

- **To build redundancies and reliability of power supply around Whitehorse, the Yukon's major load centre.** About 75% of the electricity generated on the YIS in the winter is used by homes and businesses in and around Whitehorse. New transmission assets (power lines and substations) are needed to provide a reliable supply of electricity in Whitehorse in case of a transmission or generation fault. The transmission and distribution infrastructure within and around Whitehorse is aging and was not designed to support a major load centre the size of Whitehorse. Growing electricity demand and the addition of generation resources near Whitehorse means transformation (i.e. substations) and transmission upgrades are necessary to transmit the electricity to our customers, and to increase reliability of electricity delivery to the largest concentration of Yukoners.

- **To add flexibility and increase resiliency of the system.** Yukon's electricity system was originally designed to deliver electricity one-way to customers. Now, as more options to use and self-generate electricity become available, the system needs to be ready and equipped to deliver, accept, and respond to variable sources of electricity supply and demand at a moment's notice. New infrastructure and upgrades to existing transmission lines, feeders, and substations, as well as space for the addition of new battery energy storage systems, are needed to boost our resiliency and reliability.

The Whitehorse Power Expansion is a key piece of Yukon Energy's Resource Plan – Short-Term Actions (2025-2035). Based on existing information that continues to be updated, the plan highlights capacity needed in the southern region (south of Carmacks) and in the northern region (north of Carmacks, including Faro) assuming that rental generators are removed from the system. The Short-Term Action Plan prioritizes building the capacity and transmission infrastructure needed around Whitehorse given high demands for electricity in the area. Yukon Energy's current plans outline the critical steps required to scope, design, permit, and build the necessary Whitehorse Power Expansion Project to increase reliability of electricity delivery in Whitehorse.

Why do this project this way?

Given the size, scope, and anticipated capital expenditures of this project, Yukon Energy has developed a multi-disciplinary project team with the support of external project managers and subject matter expertise. Regular updates on project status will be shared with Yukon Energy's Board Project Committee on a quarterly basis. Major contracts and major go/no go decisions will also be brought before the entire Yukon Energy Board of Directors as a way to mitigate project risks.

The Project has five areas of scope that will be reported to the Yukon Energy Board:

1. Engagement and Partnerships;
2. Siting;
3. Assessment and Regulatory;
4. Design; and
5. Construction.

Yukon Energy assumes that a Part 3 Energy Project and Operation Certificate will be required prior to start of construction of the new permanent thermal generation facilities. The anticipated process includes an OIC being issued declaring this to be a regulated project, Yukon Energy providing an application to the YUB, and the YUB holding a public hearing prior to issuance of a report and recommendations to the Yukon government who then issues the required Certificates. The process may take up to 9 months to complete and can begin once the YESAA Project Proposal is submitted. Yukon Energy will seek an Energy Certificate prior to commencing construction. To support the application, Yukon Energy will develop a business case for the Project.

5.4A-2: WAREHAM DAM SPILLWAY – FULL REPLACEMENT

Table 5.4A-2: Wareham Dam Spillway – Full Replacement Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$0	$4,114,400	$503,100	$6,905,200	$11,522,600

Project Description

The purpose of this project is to replace the existing Wareham Dam Spillway that has reached end of life. Once replaced, this spillway will serve as the secondary or auxiliary spillway as the primary spillway will be the Wareham Dam Spillway – Tunnel (see Tab 5, Appendix 5.1A).

Costs during 2025-2027 are for the development of the design from 30% to 100% design. The activities beyond 2027 include the demolition and reconstruction of the concrete chute spillway. Pending procurement outcomes and actual construction timelines the spillway chute is scheduled to be in service by Q4 2029.

It is considered best practice to have an alternative spillway or auxiliary spillway as part of a dam, especially a very high consequence dam, for safety and risk management. The primary driver for an alternative spillway is that current Canadian Dam Association (CDA) guidelines recommend redundancy. This was not a consideration when the dam came into service in the 1950s. The following considerations support building redundant capacity into the spillway:

- Meets CDA expectation for redundancy in very high consequence dams. CDA Dam Safety Guidelines (2013, 2023) emphasize the importance of providing redundancy in critical systems, including spillways, for Very High Consequence dams, to reduce risk of uncontrolled releases.

- Aligns with international best practices and risk-informed design. Major dam safety frameworks (e.g., US Federal Energy Regulatory Commission, ICOLD) advocate for redundant spillway capacity for high-consequence structures as a defense-in-depth strategy.

- Improves resilience against extreme events. Redundant spillways enhance the dam’s ability to withstand compound failure scenarios such as seismic events, landslides into the reservoir, or gate mechanical failures occurring simultaneously with high inflows.

- Reduces times where there is reliance on a single control structure. Split flow through two spillways reduces mechanical stress and operating demands on individual gates, decreasing the likelihood of failure during critical events.

- Facilitates safer maintenance and inspection. With two spillways, one can be taken offline for inspection, maintenance, or gate refurbishment while maintaining flood-passage capacity with the other, without increasing operational risk.

- Managing debris, ice, and sediment. Spillways are susceptible to debris accumulation, ice formation, and sediment buildup, which can impair flow capacity. Having two separate spillways ensures that one remains operational even if the other is temporarily obstructed.

- Optimizing the construction strategy to minimize operational and construction risks. Constructing the new spillway tunnel first allows flood management to continue uninterrupted through both spillway tunnel construction, using the existing spillway, and spillway rehabilitation, using the new, spillway tunnel.

- The recently updated Inflow Design Flood (IDF) is 600m^3/s based on the dam classification of Very High following CDA guidelines. The existing spillway chute has a capacity of approximately 400 m^3/s, meaning an increase of capacity by 200 m^3/s is required to pass the IDF. Constructing a single spillway or tunnel to pass this increased IDF has the following high-level impacts:

    - Single Spillway – To pass 600 m^3/s, the existing approximately 15 m wide and 10 m high spillway chute would be widened by at least 5 m and deepened by 0.5 m to 1 m. Considering the age of the dam (over 70 years), any excavation into the existing dam would pose significant risks to its structural integrity (such as piping, crest cracking, sink holes, core damage, settlement), which could lead to catastrophic failure.

    - Single Tunnel – Blocking the existing spillway chute and building a single, larger tunnel would increase the tunnel diameter from 4.5 m to approximately 11 m. It is anticipated that this would increase the cost of the tunnel by at least six times, which would be significantly more than providing the planned redundancy.

Why do this project now?

The Wareham spillway was originally commissioned in 1952. It provides the IDF capacity to the Wareham Lake system required for operation of the Mayo Generating Station (MGS) (both the original Mayo A [or

Mayo 0] facility commissioned in 1952, and the new Mayo B facility commissioned in 2011). There is no other spilling structure at Wareham Lake which can pass IDF or spring freshet. If the spillway is not operable 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 it is the main failure mode of earthfill dams. Therefore, the inoperability of the spillway during flood increases the risk profile of the Wareham Dam significantly.

As reviewed in Yukon Energy's 2023/24 GRA, interim concrete repairs have been required at the Wareham spillway for many years until the spillway could be permanently repaired.[2] Following the gates being deemed at the end of life in 2019 and failure of the concrete overlapping slab in 2020[3], the subsequent need was established for annual interim repairs to maintain operation of a chute at its end of life.

The need for a permanent solution as soon as possible has also been recognized for many years - aside from significant annual costs with a very limited lifespan and inability to address a range of structural risks inherent in end of life facilities,[4] annual repairs cannot address the need to increase the Wareham Dam's original design capacity from its existing 425 m^3/s to the updated required IDF of 590 m^3/s.[5] In December 2023, a Stantec memo stated ,"*Stantec has raised the concern that there is a significant risk that the spillway could fail during the next major spill event where a major spill event refers to any prolonged or large opening of the spill gates (e.g., spring freshet)".*

Yukon Energy has been actively working towards a permanent solution as soon as possible, undertaking conceptual option development, multiple account analysis of options, and site investigations to determine the most effective, cost-conscious, and timely solutions. Commitment to proceed also required regulatory planning and securing approvals and funding.

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[2] The 2023/24 GRA resulted in $1.845 million costs being added to rate base for interim repairs to the spillway between 2020 and 2023. Interim repair with a 5-year life and monitoring were implemented before the 2021 spring freshet to avoid further damage and manage failure risk until permanent repairs can be completed. The 2023/24 GRA business casefor these repairs reviewed relevant spillway history, including: issues arising from a summer 2020 project to rehabilitate one of the spillway gates; the 2002 Dam Safety Review that identified requirements for concrete overtopping over the spillway chute (and subsequent issues arising from the hoarding and construction techniques implemented); issues identified over the 1960s through the 1980s regarding erosion of the foundation under the chute, wearing of the concrete surface, constant repairs of the spillway chute (five projects executed from 1970 to 1987 to gout cracks), and movement of the spillway walls noted in 1970 and addressed in 1976.

[3] A concrete overtopping project was initiated in 2004 based on recommendations from the 2002 Dam Safety Report.

[4] Stantec provided a 2023 memo to YEC highlighting the risk exposure to YEC from deferral of permanent Wareham spillway repairs/replacement, and the suggested urgency to proceed with the permanent solution.

[5] While the spillway was initially designed to accommodate a flow of 425 m^3/s, recent studies suggest that the probable maximum flood (PMF) could reach as high as 599 m^3/s. Additionally, the updated IDF now stands at 590 m^3/s (including climate change impact), exceeding the original design capacity. With the spillway's discharge capacity estimated at approximately 400 to 430 m^3/s, there is a clear discrepancy between its capabilities and the anticipated flood discharge.

Why do this project this way?

In recognition of the significant expected overall capital cost for the selected permanent solution for the Wareham Dam Spillway (i.e., costs in the order of $150 million for all stages subject to final design and procurement outcomes), YEC also looked at costs for decommissioning the MGS as this would be the only feasible option to not proceeding with a permanent solution for the spillway. Ignoring costs to provide replacement power for the Mayo A and Mayo B hydro that would be decommissioned (and the time needed to develop equivalent new renewable generation), the cost of simply decommissioning the MGS and restoring Wareham Lake and the Mayo River has been estimated at up to $440 million.[6] YEC concluded that the selected spillway permanent solution project was clearly preferable to the option of having to decommission the MGS.

[6] Stantec memo, "Conceptual Screening Study – Cost of Decommissioning the Mayo Generating Station", February 2024. Stantec memo provides an estimate of $80 to 200 million for the decommissioning of the MGS and restoring Wareham Lake and the Mayo River. It is important to note that the cost estimate is class 5 which carries a high level of uncertainty (range of -20% to -50% at low end and +30% to +100% at the high end). Additionally, that cost does not account for the replacement of the renewable generation and does not account for the complexity of executing such a project in the remote northern environment of Mayo (>20-25%). Furthermore, there is limited information or precedent available regarding the full decommissioning of a facility like MGS, adding to the complexity and uncertainty of this option and the cost presented within the memo.

5.4A-3: PLT SHOP

Table 5.4A-3: PLT Shop Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$0	$0	$500,000	$5,000,000	$5,500,000

Project Description

This project will provide a new building on Yukon Energy owned land to store equipment and provide office space.

The Power Line Technicial (PLT) group requires a facility to store equipment and provide office space. The group currently rents office space and also rents land in Kulan for conducting their work. This project is for construction of a new building on Yukon Energy owned land.

Project Alternatives

The PLT group could continue to work at their existing property rented in Kulan, adjacent to the Yukon Energy warehouse, and renew the lease. Alternatively, consideration is being given to building a new shop on Yukon Energy owned property at the Kulan Warehouse.

Why do this project now?

The lease for the existing PLT shop expires in 2028.

Why do this project this way?

Initial high-level assessments show it is expected the construction of a new PLT shop on Yukon Energy owned land has a lower rate impact compared to renewing the existing lease. Additionally, a new building can be customized to meet the exact needs of the Corporation.

5.4A-4: MAYO MH0 PLANT RENEWAL OR REPLACEMENT

Table 5.4A-4: Mayo MH0 Plant Renewal or Replacement Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$0	$0	$1,000,000	$2,500,000	$3,500,000

Project Description

The Mayo MH0 Plant and units are at end of life. This project will be to renew or rebuild the plant.

Why do this project now?

The timing needs to be aligned with financing availability, Wareham Spillway construction and First Nation stakeholder expectations. The Mayo Rock Slope Stabilization and Remediation project is the first step and is expected to commence in 2025.

Why do this project this way?

The significant planned work at Mayo including the Mayo Rock Slope Stabilization and Remediation project, the Wareham Spillway Replacement, and Mayo Plant Renewal or Replacement all require coordination. These activities may require authorization from the Yukon Water Board and/or result in amendments to the existing license for the MGS.

5.4A-5: WRGS OFFICE BUILDING

Table 5.4A-5: WRGS Office Building Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$0	$500,000	$1,000,000	$2,000,000	$3,500,000

Project Description

This general plant project is to provide suitable office space at the Whitehorse Rapids Generating Station (WRGS) for the existing employees currently working in an unreasonable work environment and for the expected growth in Yukon Energy employee complement.

Increasing loads are increasing workload resulting in an increase in both the number of employees and consultants. Where possible, Yukon Energy supports managing workload by increasing employees. Yukon Energy currently has approximately 123 full-time equivalent (FTE) employees and is forecasting FTEs to increase to approximately 144 FTEs by 2027 and to approximately 155 by 2029. This represents an increase of approximately 60 FTEs since 2020.

To date, Yukon Energy has managed FTE growth by: having employees work from home either part or full-time, sharing desk space, creating more office space within existing buildings, replacement of a office trailer with an expanded office trailer, moving employees off-site to rented property in Kulan, and filling empty spaces. All departments have developed some form of office sharing to reduce office space requirements. For example:

- In the Finance department, seven FTEs occupy just three offices as they rotate working from home and in the office, or work from home full-time.
- In the Information Technology department, five FTEs occupy two offices and the remainder work from home.

Yukon Energy has employees housed in seven different buildings, including five located at the WRGS. The current WRGS office space includes employees working in unreasonable conditions, including thirteen employees in two trailers (1990’s vintage) converted to offices and thirteen employees sharing desks working in a small section within the diesel plant that was originally built solely for generators and still has four operational diesel generators.

Project Alternatives

Yukon Energy has investigated both rental of office space as well as the construction of a new office building. Construction of an office building has been considered on WRGS property as well as off property. In summary, the alternatives considered were:

- Rental of office trailers to be located at the WRGS;
- Rental of downtown Whitehorse office space;
- Construction of a new building located off of the WRGS; and
- Construction of a new building located within WRGS (on Yukon Energy owned land).

Yukon Energy obtained preliminary quotes for rental of office trailers and rental of downtown Whitehorse office space and found the costs to be comparable. However, the conditions of the office trailers were determined to not meet the objectives of providing a reasonable work environment for various reasons, such as there was no running water able to be provided within the office trailers.

Yukon Energy investigated rental of property off of WRGS for construction of a new office building. Location of a rental property was narrowed down to additional space at the BESS site due to its close proximity to WRGS. However, due to lack of services and high costs, a high occupancy construction at the BESS site was determined to be not feasible.

The remaining alternatives of rental of downtown Whitehorse office space and construction of a building located within WRGS were compared and found to be similar financially.

Why do this project this way (Recommendation)?

A building at WRGS has the added benefit of allowing more staff to work more closely together and proximity to Yukon Energy's main generation site.

Completion of the WRGS Office Building will depend on financing availability and project spending prioritization.

5.4A-6: CARMACKS SUBSTATION RELOCATE

Table 5.4A-6: Carmacks Substation Relocate Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$0	$0	$250,000	$3,000,000	$3,250,000

Project Description

This transmission project is to relocate the Carmacks Substation.

The Carmacks transformer is aging and the Carmacks load is growing. In addition, there is a need to have more sophisticated remote sensing and switching control.

Why do this project now?

The transformer on site has known issues. There are safety issues with the aging switch and ground grid at the site.

Why do this project this way?

Funding is being advanced to begin feasibility work and a business case which will provide details regarding the requirements for the relocation of the Carmacks substation. Feasibility work starting in 2026 would have a new substation in service in three to four years.

This project is being undertaken for the following reasons:

1. **Advantages of Relocation to S255 Site, close to the Carmacks Airport**

   - S255 has existing buswork, yard infrastructure, and remote communications.
   - Site supports installation of distribution breakers, 138kV circuit switchers, and protection relays.
   - Less exposed to vandalism, being farther from town.
   - Easier access for operation, maintenance, and emergency response.

2. Aging Equipment and Increasing Failure Risk

- The transformer is 55 years old (manufactured in 1970), exceeding the typical life expectancy for transformers.
- Dissolved Gas Analysis (DGA) shows signs of arcing and partial discharge, indicating internal insulation issues.
- No immediate failure is expected, but the risk is increasing.

3. Site Access and Operational Limitations

- The existing site is located on a steep hill above Carmacks with seasonally limited vehicle and equipment access.
- Vandalism risk is high due to the isolated location.
- The transformer pad is tilting and unlevel, requiring major maintenance.
- No spill containment; the transformer is leaking oil and cleanup would be logistically challenging and costly.

4. Safety and Environmental Concerns

- No fall arrest system installed, and retrofitting is unlikely due to age.
- Substation yard is in poor condition.
- Increased worker safety risks due to potential step and touch hazards.

5. Lack of Modern Protection and Control

- The substation lacks remote monitoring, switching, or control capabilities.
- Protection consists only of passive fuses and switches – no relays or fault detection.
- No visibility of transformer load or temperature from remote locations.
- No on-site security or surveillance, only a basic fence.

5.4A-7: WH1 UPRATE

Table 5.4A-7: WH1 Uprate Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$0	$0	$250,000	$2,000,000	$2,250,000

Project Description

This project will uprate Whitehorse Hydro Unit 1 (WH1).

WH2 was successfully uprated over 2018-2021. The efficiency gains were substantial, and the unit has been fully modernized. WH1 will be uprated to increase efficiency and output. The scope includes replacing the runner and windings as well as modernizing the governor, exciter and protection and control system. This would add energy, capacity and reliability to the WH1 unit. The project will include replacement of the Kaplan runner, oil head, governor/hydraulic power unit, exciter, unit controls, and high-pressure oil injection system, etc.

Why do this project now?

WH1 has been in service for 65 years and many of the auxiliary systems/components are at end of life:

- The runner is leaking oil.
- The governor is the original ballhead governor and not a L&S Digital Governor per current standards.
- The unit controls are outdated (using Schneider programmable logic controller).
- The rotating exciter is outdated.
- The runner design and improvements can increase capacity and efficiency.

Why do this project this way?

The benefits of tackling a major project to uprate and upgrade the unit in a single project versus many smaller projects for each system are as follows:

- Cost savings;

- Reduced reliance on internal resources to manage multiple contactors;
- Less burden on procurement department; and
- Less chance of compatibility issues.

5.4A-8: RENEWABLE RESOURCE PROJECTS

Table 5.4A-8: Renewable Resource Projects Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$0	$0	$400,000	$500,000	$900,000

Project Description

This is a placeholder to set baseline funds required to build-out renewable resource projects such as wind and battery. The amount of spending and in-service of projects is uncertain at this time.

Why do this project now?

The project will commence after release of Yukon Energy's Strategic Plan and Integrated Resource Plan.

Why do this project this way?

It is anticipated that the Strategic Plan and Integrated Resource Plan will provide guidance to Renewable Energy projects such as a call for power.

5.4A-9: EV INFRASTRUCTURE TRANSITION

Table 5.4A-9: EV Infrastructure Transition Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$0	$35,000	$125,000	$500,000	$660,000

Project Description

This distribution project involves collaborative research and planning assessments for the Electric Vehicle (EV) charger transition from Yukon government to utility ownership.

Studies and research are required to assess current EV ownership/transfer models across Canada, assess availability and use and Information Technology (IT) requirements for Measurement Canada. Yukon Energy plans to collaborate with AEY to co-fund and scope research, market scans, and IT requirements for the EV transition from Yukon government to utility ownership.

Why do this project now?

This project is required now as new $/kWh EV charging meters are expected, there is a need to determine customer retail/payment options and requirements, regulatory issues for new EV rates, and possible First Nation business models, amongst other things.

Why do this project this way?

Transition to EVs will occur whether we plan for it or not. Utilities will have to adapt and have an in-depth analysis completed for technical, financial, regulatory and operational aspects of the business in any case.

Without planning, there is no financial investment upfront. However, having no foresight or planning will in the end be costly and could detrimentally affect key partnerships and public perception.

Yukon Energy believes a better approach is a comprehensive EV transition study. This would provide Yukon Energy with actionable recommendations for a successful transition. It would provide additional cost savings by doing it right the first time. It offers a comprehensive understanding of the potential impact that the EV transition will have on costs, benefits and operations. It provides a roadmap for a smooth transition by addressing potential pinch points and challenges. In summary, it minimizes risk for the Corporation.

5.4A-10: ERP REPLACEMENT

Table 5.4A-10: ERP Replacement Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$118,200	$500,000	$0	$0	$618,200

Project Description

This intangible asset project aims to implement a new Enterprise Resource Planning (ERP) system to replace the existing Microsoft Dynamics Great Plains system.

The project will be divided into two phases: Sourcing and Implementation. The Sourcing phase will involve identifying business requirements, developing an RFP, evaluating vendor responses, and selecting a new ERP system. The Implementation phase will include project planning, system installation and configuration, data conversion, testing, training, and system rollout.

Why do this project now?

Yukon Energy faces a critical challenge with its current ERP system, Microsoft Dynamics Great Plains, as the end-of-life for this system is 2029. In addition, licensing costs are continuously increasing and the system's limitations are hindering operational efficiency and growth. Yukon Energy needs a long-term, comprehensive solution to address these challenges and support its evolving business needs.

The Microsofty Dynamics Great Plains system was fully amortized in 2022.

Why do this project this way?

Yukon Energy currently has only forecast costs for the Sourcing phase. The Implementation phase is not yet forecastable as it is highly dependent on the service provider selected. As a result, forecast costs for 2026 and future years are not yet available at this time. Due to the complexity of an ERP transition, in-service is not likely to occur during the GRA test years.

5.4A-11: P126 BUILDING RENOVATION

Table 5.4A-11: P126 Building Renovation Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$0	$0	$100,000	$500,000	$600,000

Project Description

This project will renovate and upgrade the Whitehorse Diesel Plant.

This project presumes continued use of the Whitehorse Diesel Plant. This decision reflects the outcome of an emissions study and resource planning.

- YEC engaged BBA in 2014 to assess the P126 diesel plant building condition; BBA recommended some minor repairs to the building, but the recommendations were not implemented.

- As part of the Whitehorse Thermal Replacement project, in 2020, BBA was tasked with the responsibility to complete a Design Basis Memo (DBM) for the P126 Building Renovation so that the two new 2.5 MW generators could be housed inside the building.

- However, a geotechnical investigation was required to determine the foundation site class for the building renovation. The geotechnical investigation reports prepared by BBA and Tetra Tech, dated March 6, 2020 and July 26, 2021, respectively, identified liquefiable soils in the location of P126 diesel plant. The identification of potentially liquifiable soils and high lateral and horizontal deflections underlying the building has provided cause for considering seismic performance upgrades of the building as part of the renovation to meet current building code. Any renovation to the building must be done to current code as the existing building was not designed to meet the seismic requirement of the current National Building Code of Canada (NBCC).

- Yukon Energy has since decided to go with a modular design for the Whitehorse Thermal Replacement because of the timeline and cost to get the building renovation completed.

- However, the existing generators inside the building have 15-20 years of remaining service life. Therefore, the feasiblity of any renovations that would trigger NBCC upgrades to comply with the current code must be considered.

In addition, Yukon Energy is currently considering to use the WD1-WD3 bay as a warehouse once the renovation is complete. Asbestos issues exist in the plant that will also need to be addressed.

Why do this project now?

Renovations are required to make use of the existing space where diesel generators were previously located and upgrade the building to current code.

5.4A-12: T9 TRANSFORMER CRITICAL SPARE

Table 5.4A-12: T9 Transformer Critical Spare Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$58,200	$75,000	$325,000	$1,400	$459,600

Project Description

This project provides critical spare and installation of a firewall at T9 transformer, located at the WRGS behind the WH4 Plant.

T9 is an aging transformer. It is a single point of failure, supplies large loads, and is required for N-1 scenarios. The scope includes requirements for installation of a firewall.

Costs to date include transformer assessments and testing including visual checks, surge arrester testing, insulation resistance, ratio test, winding resistance, dielectric frequency response, oil DGA analysis, thermal imaging for hot spots, bushing CT (current transformer) test, complete electrical and non-electrical tests.

Costs in 2026 are forecast to be for procurement requirements.

Why do this project now?

Long lead times for large power transformers are in the range of 4-5 years. In the case that the transformer begins to show signs that it is at risk of failing internally, Yukon Energy will be unlikely to procure a replacement before the unit itself fails, resulting in a potentially long, and expensive failure.

Why do this project this way?

Due to the high cost of a transformer, significant planning is required to reduce risk and provide for the best possible decision.

5.4A-13: PROTECTION AND CONTROL – S170

Table 5.4A-13: Protection and Control – S170 Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$18,600	$434,000	$0	$0	$452,600

Project Description

This project will provide protection and control equipment for S170. Assessments need to be conducted prior to moving forward with completion of this project. Therefore, due to uncertainty, this project has not been included in rate base and remains in work-in-progress.

Yukon Energy engaged SNC Lavalin in 2020 to complete a system wide assessment of its protection, control and SCADA assets as part of the Physical Asset Management Managed System (PAMMS) implementation. The assessment included a site visit, data collection of assets, and evaluation of equipment asset health indices (AHI) based on age, obsolescence, physical condition and type. SNC has developed a 20-year asset management plan to replace protect and control assets in the Yukon Energy electrical grid.

Yukon Energy prioritizes upgrade of protection and control electronic devices and protection schemes on a 20-year cycle on a basis of device obsolescence, typical reliable service life of electronic equipment, and a need to adapt protection and control equipment and schemes to an evolving operating, communication, and technology environment.

Why do this project now?

Most of the protection, control and SCADA equipment at this site are at end of life with no spares available for replacement (vintage equipment) should a failure occur.

Why do this project this way?

This is consistent with Yukon Energy's 20-year asset management plan for protection and control devices, as developed by SNC Lavalin in 2020.

5.4A-14: PROTECTION AND CONTROL – WD0

Table 5.4A-14: Protection and Control – WD0 Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$0	$0	$0	$400,000	$400,000

Project Description

This project provides protection and control equipment for the Whitehorse Diesel Plant (WD0).

Yukon Energy engaged SNC Lavalin in 2020 to complete a system wide assessment of its protection, control and SCADA assets as part of the PAMMS implementation. The assessment included site visit, data collection of assets, and evaluation of equipment asset health indices (AHI) based on age, obsolescence, physical condition and type. SNC has developed a 20-year asset management plan to replace protection and control assets in the Yukon Energy electrical grid.

Yukon Energy prioritizes upgrade of protection and control electronic devices and protection schemes on a 20-year cycle on a basis of device obsolescence, typical reliable service life of electronic equipment, and a need to adapt protection and control equipment and schemes to an evolving operating, communication, and technology environment.

Why do this project now?

WD0 protection is still the original mechanical relays from 1975. These relays are now obsolete, and the protection and control system needs to be modernized to ensure generator protection as well as remote monitoring.

Why do this project this way?

This is consistent with Yukon Energy's 20-year asset management plan for protection and control devices, as developed by SNC Lavalin in 2020.

APPENDIX 5.4B
DEFERRED PROJECTS >$400,000 REMAINING IN WIP

APPENDIX 5.4B: DEFERRED PROJECTS >$400,000 REMAINING IN WIP

5.4B-1: ATLIN HYDRO ENERGY PURCHASE AGREEMENT

Table 5.4B-1: Atlin Hydro Energy Purchase Agreement Costs Remaining in WIP

Opening WIP	2025	2026	2027	Ending WIP
$1,682,100	$100,000	$0	$0	$1,782,100

Project Description

The Atlin Hydro Expansion Project was identified in Yukon Energy's 10-Year Renewable Electricity Resource Plan. This led to the negotiation of an Energy Purchase Agreement (EPA) between Yukon Energy and Tlingit Homeland Energy Limited Partnership (THELP). Project costs include the legal and contractor costs to negotiate the Atlin EPA and accompanying agreements.

2023/24 GRA

As stated in Yukon Energy's 2023/24 GRA compliance filing, the central issue raised by the Board in the 2023/24 GRA was the current viability of the project. Directive 20 (paragraph 326) of Board Order 2024-05 requires YEC to "confirm the project remains viable and there is a reasonable probability that the project will proceed"; further, if this confirmation cannot be provided, the Board's directions may require that the project be expensed in 2024 as per paragraph 312 of the Reasons for Decision. In its compliance filing Yukon Energy noted that, at the time, there was still uncertainty about the project's ultimate viability; the project was still being pursued, and Yukon energy could not confirm, with certainty, that the project would not proceed. In particular:

- The EPA conditions precedent between Yukon Energy and THELP has been extended to November 30, 2024, confirming that the EPA was still alive.
- Yukon Energy understood that THELP was still involved in active permitting discussions as it continued to advance undertaking a substantial geotechnical investigatory program and price optimization.
- Yukon Energy understood that there had also been a very recent approval/support issued from Taku River Tlingit First Nation for the project.

- The project required significant government funding, not yet committed, in order to proceed. As highlighted by Yukon Energy in the 2023/24 GRA, the project was referenced in the 2023 Federal Budget, however, no clear funding mechanisms were provided, and no reference was provided in the 2024 Federal Budget. However, Yukon Energy alongside YDC and THELP continued discussions with both federal and territorial government officials to explore funding avenues to support the project.

Yukon Energy's conclusion in the 2023/24 GRA compliance filing was that although there were significant uncertainties such that Yukon Energy could not confirm that there was a reasonable probability that the project would proceed, ongoing work continued to be demonstrated for the project. Under these circumstances, Yukon Energy would not cancel the project at that time and would, under its current practices, maintain the project cost in CWIP. Yukon Energy noted, however, that if the Board's review of the above information concluded that the cost should be expensed in accordance with the directives provided in paragraphs 312 and 326 (Directive 20), then Yukon Energy would provide revisions to the compliance filing with inclusion of $1.253 million as an expense for 2024 (on the grounds that the evidence leading to current conclusions occurred during 2024, after the conclusion of evidence provided during the current GRA proceeding).

The Board, in its response to the compliance filing, did not provide specific comment on the Atlin Hydro EPA costs. As such, Yukon Energy did not cancel the project and under its then current practices, maintained the project cost in CWIP.

Project Update

Yukon Energy has not performed significant work on this project since the 2023/24 GRA. The most significant update is that the EPA conditions precedent between Yukon Energy and THELP have been extended to June 30, 2025, confirming that the EPA is still alive.

The 2025 forecast costs are dependent on finalization or extension of the conditions precedent.

Capital contributions of $355,800 partially offset project costs.

Conclusion

Based on current information and guidance from the prior GRA, it is Yukon Energy's position that at the time of filing the 2025-2027 GRA there is still uncertainty about the project's ultimate viability; the project is still being pursued; and Yukon Energy cannot confirm, with certainty, that the project will not proceed.

Under these circumstances, Yukon Energy would not cancel the project today and would maintain the project cost in CWIP. Updates provided during the current GRA proceeding may change this conclusion.

As stated in Yukon Energy's 2023/24 GRA compliance filing, if the Board concludes in this proceeding that project costs should now be expensed, Yukon Energy will provide a compliance filing that includes $1.682 million less capital contributions of $0.356 million, the December 31, 2024 ending WIP, as an expense for 2025.

APPENDIX 5.5
CHANGES IN PROJECTS FROM PREVIOUS GRA

APPENDIX 5.5: CHANGES IN PROJECTS FROM PREVIOUS GRA

5.5A-1: PROJECTS INCLUDED IN PREVIOUS GRA

The 2023/24 GRA included forecast costs for some projects that were not yet completed. The opening 2025 rate base includes adjustments to reflect actual costs to these projects. Capital projects reviewed and approved in the 2023/24 GRA with variances greater than $100,000 added to rate base for the 2025-27 GRA as summarized in Table 5.4-1 are detailed below.

Vehicle Purchases (Rate base increase of $0.323 million) – The 2024 Vehicle Purchases forecast in the 2023/24 GRA included one ½-ton pickup truck, one ¾-ton pickup truck, and three 1-ton trucks (two with service bodies). Actual 2024 purchases consisted of three ½-ton pickup trucks, one ¾-ton pickup truck, four 1-ton pickup trucks and one SUV. The unplanned purchases in 2024 consisted of:

- ½ ton pool vehicle for allocation to Health & Safety.
- ½ ton pool vehicle for replacement of unit #132 that experienced blown engine.
- 1 ton vehicle for growth in T&D department.
- 1 SUV pool vehicle for Dawson.

HQ DataCentre Server Replacement (Rate base increase of $0.192 million) – Yukon Energy received 3 quotes for this work, all of which exceeded expectations due to more complexity than anticipated. The lowest cost bidder was selected.

Wareham Dam Spillway Concrete Repair (Rate base increase of $0.437 million) – Details regarding this project were provided in Appendix 5.1A, page 5.1A-24 which states: "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." After further review of the Wareham Spillway, the permanent replacement is still in the planning phase due to complexity and potential cost. Therefore, additional interim temporary fixes were required in 2024.

Schwatka Lake Safety/Debris Boom (Rate base increase of $0.123 million) – The boom was installed in late 2023 as forecast in the 2023/24 GRA. However, after installation, deficiencies were noted. The boom was stretched very tight, resulting in higher loads on the boom when the ice breaks up on the lake.

During 2024, more boom materials were ordered and more boom sections installed in mid-2024 so the boom was not stretched as tight. Some other hardware adjustments were also made for durability.

5.5A-2: PROJECTS NOT INCLUDED IN PREVIOUS GRA

Yukon Energy incurred costs on projects that were not forecast in the 2023/24 GRA. These emergent projects are included in the opening 2025 rate base. Capital projects not forecast in the 2023/24 GRA with costs greater than $100,000 added to rate base for the 2025-27 GRA as summarized in Table 5.4-2 are detailed below.

Mobile Diesel Generators (Rate base increase of $0.749 million) – Outages during the winter (2022-2023) highlighted that Yukon Energy does not have enough mobile generation to supply rural communities during outages. The solution was to purchase two mobile generators with larger capacity so Yukon Energy can provide an emergency supply of power to communities that do not have local backup power. Yukon Energy purchased two Doosan Bobcat PG570 mobile diesel generators after tendering a public bid.

WD7 Generator Reconditioning (Rate base increase of $0.109 million) – Through operating Yukon Energy noticed WD7 stator is prone to overheating and often needs to be operated at 2.5 MW rather than 3 MW. Electrical testing showed the unit requires refurbishment. This project included removing the generator and sending it down south for refurbishment. The WD7 generator was reconditioned complete with new bearings.

Aishihik Intake Inspection (Rate base increase of $0.158 million) – As part of the 2020 Dam Safety Review (DSR), it was recommended to perform an inspection of the intake portal for the Aishihik Generating Station (AGS). The intake has not been inspected since the AGS was constructed in the mid-70's (almost 50 years). There is no baseline information available to review the works. The objective was to have a 3D scan of the intake to see if there were any issues and to provide a baseline for future inspections, or should a seismic event occur that would require an inspection. Using a remotely operated vehicle (ROV) allowed for inspection of portions of the intake that had not previously been accessible. The survey data that was collected by the ROV will also allow for tracking of any changes in the future. There are no alternatives to this approach to undertaking the work. Previous attempts using a camera did not produce results. It was decided to complete the project in 2024 as the current condition of the intake was unknown. Additionally, this work should be conducted in 2024 ahead of the 2025 DSR, so the data can be incorporated into the review.

L171 Structure Replacement (Rate base increase of $0.259 million) – Yukon Energy T&D performs ground-based patrols of select lines on an annual basis. In 2024, power line technicians performed an inspection of L171. During the inspection several structures were identified as compromised and being at increased risk of failure. A total of seven structures were identified as deficient and in need of immediate replacement. Given the state of these structures as part of the main feeder between Aishihik and Tankini any structure failure would translate to a major loss of generation equaling or up to 38 MW. These structures were replaced in the summer of 2024.

Load Bank and Transformers (Rate base increase of $1.723 million) – Load banks are essential tools for testing and maintaining power generation and distribution systems. They simulate real-world electrical loads, allowing Yukon Energy to:

- Verify the performance and stability of new and existing power generation equipment.
- Ensure reliable operation of backup power systems.
- Conduct preventative maintenance and identify potential issues before they impact operations.
- Commission Battery Energy Storage Systems (BESS) safely and effectively.

The load bank will be used for commissioning the new thermal sites as well as the BESS. The critical timing of commissioning both the new thermal sites (Faro and Callison) is the primary driver. These projects are key to ensuring reliable power, especially during peak winter demand. Yukon Energy needs to address the risk of grid instability during winter. Cold temperatures put significant strain on the grid, and without thorough testing there is increased risk of power outages, equipment damage, and public safety hazards. Yukon Energy's recent experience in Faro shows that extensive load bank testing revealed critical issues that, if left unaddressed, would have resulted in significant operational problems.

A load bank was not previously considered critical. However, because of new technology and the amount of effort to integrate more complex projects like BESS and advanced thermal plants, it now is considered critical. This increased complexity demands more rigorous testing than in the past for these new sites. Older plants did not have the same level of interaction required. Also, the critical need to test in winter conditions is a new requirement, which increases construction requirements. Regulatory requirements and industry best practices are also evolving and require more comprehensive commissioning procedures.

Purchase of a load bank provides significant cost savings compared to a rental option. With a monthly rental cost of approximately $170,000 and a minimum rental period of 6 months, Yukon Energy would incur rental expenses of around $1,020,000 ($170,000/month x 6 months) for the initial projects. The purchase cost of the load bank and transformers is $1.723 million, resulting in a payback of less than one year. While the upfront cost of purchasing is higher, Yukon Energy would own valuable assets with a lifespan of 20-25 years. This eliminates ongoing rental expenses and provides a resource for future projects. In addition, owning the load bank ensures its immediate availability whenever needed, eliminating potential scheduling conflicts and project delays associated with rentals.

This is not a one-time-use purchase. The load bank will be a valuable asset for ongoing maintenance and testing and all Yukon Energy facilities moving forward. Examples of use cases are summarized below:

- **BESS Testing:** It will be used for routine BESS testing, including capacity, response time, and state-of-health monitoring. BESS systems, by their nature, require more frequent and detailed testing than traditional thermal plants.

- **Periodic Performance Testing:** It will be used for periodic performance testing of both the BESS and any thermal plants subject to changes, ensuring continued reliability.

- **Troubleshooting and Diagnostics:** It is a critical tool for troubleshooting and diagnosing grid and generating facility issues, reducing downtime and repair costs.

- **Training:** It can be used for training personnel on the operation and maintenance of these new systems.

- **Future Projects:** As Yukon Energy continues to deliver the capital plan and upgrading the grid, the load bank will be essential for future projects.

In summary, the load bank is an essential risk mitigation tool. Without it, the risk of commissioning these major projects is unacceptably high. It is a form of insurance that these projects will function as designed and protect the grid.

Tailrace Gate Certifications (Rate base increase of $0.552 million) – The WH4 tailrace gate and headgate needed to be certified. Certification is required to enter the confined spaces (draft tube, scroll case, penstock). Yukon Energy typically follows a single device isolation certification (SDIC) industry standard process. These confined spaces need to be entered annually for inspections and cavitation repairs. Work required on the gates included replacing bent springs and side rollers, replacing volute springs on the headgate side rollers, replacing seals, structural analysis and certification.

Mayo Bucket Truck (Rate base increase of $0.362 million) – The town of Mayo had a small bucket truck, with limited reach, that was very unreliable. A bucket truck is an integral piece of equipment used to complete O&M, capital and outage response in the north. A bucket truck is a key piece of equipment for powerline technicians to use in their day-to-day work and to provide the ability to respond to issues. This project is to purchase a bucket truck to replace the current Unit 88 that is at end of life. This improves reliability of the Northern region.

Unit 88 was a 2008 model with 126,000 kms. Unit 88 was in the shop for repairs. This unit typically saw repairs once very few months. Each repair is at minimum $2,500; and is usually more if the unit needs to be hauled from Mayo to Whitehorse. Renting is not a sustainable option. Current rental costs can be $4,725 weekly, and roughly $18,900 monthly. The payback for purchasing a bucket truck is less than two years.

Mayo Digger (Rate base increase of $0.454 million) - The town of Mayo had an aged digger truck that has been very unreliable; the truck had been at the shop for repairs for almost 18 months. Repairs did not proceed as the cost was more than the unit was worth. A digger truck is a key piece of equipment for powerline technicians to use in their day-to-day work and to provide the ability to respond to issues. This project is to purchase a digger truck to replace the current Unit 49. This improves reliability of service in the Northern region.

Unit 49 was a 1999 model with 120,029 kms and 5623 power take off (PTO) hours. When operational, this unit typically sees repairs once very few months. Each repair is at minimum $2,500; and usually more if the unit needs to be hauled from Mayo to Whitehorse. Renting is not a sustainable option. Current rental costs can be $4,725 weekly, and roughly $18,900 monthly. The payback for purchasing a bucket truck is approximately two years.

TAB 6
BOARD DIRECTIVES

6.0 BOARD DIRECTIVES

This Tab reviews outstanding directives contained in prior Board 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 amended 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 2023-2024 General Rate Application.

6.1 BOARD ORDERS 2024-05, 2024-12, 2024-13, AND 2025-08 – YUKON ENERGY 2023-24 GENERAL RATE APPLICATION & RELATED COMPLIANCE FILINGS, AND YUKON ENERGY 2024 LOW WATER RESERVE FUND ANNUAL REPORT

On August 31, 2023, Yukon Energy Corporation filed an application with the Board, pursuant to the *Public Utilities Act* (PUA) and OIC 1995/90 for approval of its forecast revenue requirements for the 2023 and 2024 test years. The 2023 and 2024 test years revenue requirements were approved subject to Board ordered adjustments pursuant to directions provided in Order 2024-05. Yukon Energy filed its Compliance

Filing regarding Order 2024-05 with the Board on August 5, 2024. Order 2024-13 was provided on September 13, 2024, noting that the Board approved Yukon Energy's August 5, 2024 submission as filed. Yukon Energy's requested changes to Yukon Energy rate riders, Rate Schedule 39 Fixed Charge, RS39 Fixed Charge true-up, Average blended fuel price, IPP Deferral Account and Low Water Reserve Fund (LWRF) Term Sheet were also approved, effective October 1, 2024 (Appendix A, paragraph 25).

Order 2024-05 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.

Separately, on February 28, 2025, Yukon Energy filed, pursuant to its LWRF Term Sheet as approved in Board Order 2024-13, correspondence with the Board on the 2024 LWRF Report and ERA Filing. Board Order 2025-08 issued on April 24, 2025, approved Yukon Energy's filing but also directed Yukon Energy in its next GRA to address an issue related to the use of Fish Lake hydro. This Fish Lake issue is addressed in Section 6.3 below.

6.1.1 Directives related to Revenue Requirement

Fuel and Purchased Power (paragraph 89)

> *"The Board shares the concern expressed by Mr. Maissan regarding the blended fuel ratio of 90/10 (LNG/diesel) and directs YEC to demonstrate, at the time of its next GRA, that the blended thermal ration proposed by YEC is the correct LTA blended fuel mix."*

See Tab 3, Appendix 3.3, which provides a detailed response to this directive with a proposed change in fuel mix to 80% LNG/20% diesel.

Production Expense (paragraph 137)

> *"…. YEC is directed, in its future applications, to provide a strong industry based and accepted approach on what the manufacturers accept as criteria and evidence for uprating thermal generation units. This can be based on documented industry standards".*

See Tab 2, Section 2.4 which provides a detailed response to this directive.

Insurance Costs and RFID Account (paragraph 170)

> *"…. The Board continues to direct 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 3.3.6.1 which summarizes and explains the basis for the insurance cost increase for 2025, 2026 and 2027 and the steps Yukon Energy is taking to potentially reduce costs in the future.

6.1.2 Directives related to Capital Projects

EAM/PAMMS Project (paragraph 270)

> *"…. YEC is directed to provide reporting on the EAM/PAMMS project that quantifies; improvement in reliability measures; real cost benefits from inventory management; direct and real labour savings; measures that can show improvements in YEC's asset health; and any other measure that YEC can add that will help the Board and interested parties assess the overall benefit of this project".*

See Appendix 6.1 for details on how this has been addressed.

Southern Lakes Enhanced Storage Project (paragraph 312)

> *"…. the Board directs YEC to examine and redefine its processes for similar major deferred capital projects and to only capitalize those costs once it is determined that there is a reasonable probability that that project will go forward and to reflect, as necessary, any changes that may be required to YEC's capitalization policies and supporting documents. On a go-forward basis, YEC is to explore and provide an alternative for the treatment of costs incurred for such projects until it has obtained a reasonable probability that the project will proceed. For example, this could be done by expensing the costs as incurred (until a reasonable probability of proceeding is determined) or treating the costs as no-cost capital (with or without debt and/or equity financing). In the case of cancelled projects, it should be clear to customers that the amounts that are included in rates are for cancelled projects. As there is no asset, YEC is to expense all costs for the project in the year*

the project is cancelled and reflect this change in YEC's capitalization policies and supporting documents".

See Tab 3, Section 3.3.5.1 which details the change in capitalization policy.

Deferred Costs: Projects >$1 Million (paragraph 334)

"…YEC is directed to provide with its application a summary of the historical activity and current status for each of the Whitehorse water use licence renewal, Mayo Generating Station water use licence renewal, and the Mayo Lake Storage and 2024 Resource Plan projects and the same information for any other project for which significant balances of CWIP (such as those projects identified in paragraphs 247-248 above) are forecast to remain at the end of the next test period".

See Tab 5, Sections 5.2.3 and 5.3.3 which summarizes capital and deferred projects in work-in-progress at the end of the final test year.

Deferred Costs: Projects between $100,000 and $1 Million (paragraph 343)

"…In its future applications, YEC should include information specific to how each of its proposed deferred projects meet the capitalization criterion set out in Finance Policy, FA-106".

See Tab 3, Section 3.3.5.1 which details a change in capitalization policy and the transition period.

General Matters (paragraph 402)

"…directs YEC in its compliance filing to this Board Order and in each future GRA application to provide CWIP continuity information as shown in the template provided by the Board in Appendix A to this Board Order.

See Tab 5, Tables 5.2 through 5.8.

6.1.3 Directives related to additional matters to the GRA

LWRF Account (paragraph 384 and 386)

> *"The Board directs YEC, at the time of its next GRA, to clarify and explain if the LWRF and other deferral accounts are part of working capital and contribute to the determination of the utility's revenue requirement".*

As noted in Yukon Energy's compliance filing for the 2023-24 GRA, the LWRF and other deferral accounts are not part of the working capital that contributes to the determination of the utility's revenue requirements.

> *"…. YEC is directed to populate and provide the following table for each year since 1989 regarding the LWRF balance as part of its compliance filing to this Board Order and to continue to provide updates to this table as part of it future general rate applications".*

The table, as directed by the Board, is provided as part of the annual LWRF filings with the Board.

6.2 BOARD ORDERS 2023-21, 2024-07, 2024-09 AND 2024-10

Cost awards were determined after the joint ATCO and Yukon Energy Rate Rebasing proceeding, the Yukon Energy 2021 LWRF and ERA proceeding, and the Yukon Energy 2022 LWRF and ERA proceeding. The Board provided the following directives related to hearing cost awards for each of these proceedings:

- ATCO and Yukon Energy Rate Rebasing Proceeding (Order 2023-21 - Erratum):
    - "YEC and AEY shall pay in equal share the following amounts identified within 30 days of issuance of this Order. The Board directs YEC and AEY to record these hearing-related costs in its Hearing Costs Reserve Account."
- Yukon Energy 2021 GRA Phase 2 Review Cost Awards (Order 2024-07):
    - "The Board finds that the total cost awarded as hearing-related costs of the Review Application shall be deemed utility regulatory costs and shall be added to the utility's rate case reserve fund."

- Yukon Energy 2021 LWRF and ERA proceeding (Order 2024-09):
  - "The Board finds that the hearing-related costs of the Application shall be deemed utility regulatory costs and shall be added to the utility's rate case reserve fund."
- Yukon Energy 2022 LWRF and ERA proceeding (Order 2024-10):
  - "The Board finds that the hearing-related costs of the Application shall be deemed utility regulatory costs and shall be added to the utility's rate case reserve fund."

Yukon Energy has established a Hearing Cost Reserve Account in accordance with the direction provided in Board Order 2013-03, and Yukon Energy has amortized hearing-related costs to this account for the above proceedings as directed by the Board (see Tab 3, Section 3.4.4.1).

6.3 BOARD ORDER 2025-08: 2024 LOW WATER RESERVE FUND ANNUAL REPORT

Board Order 2025-08 Appendix A (paragraph 29) raised the following issue regarding the use of Fish Lake hydro that Yukon Energy is directed to address in its next GRA:

> *"The Board is concerned with YEC's use of LTA for Fish Lake Hydro. In note 1 to the MS Excel spreadsheet, entitled "Table 1.1 – LWRF 2024", YEC states that OIC 2021/16 requires use of LTA average renewable resource energy for generation forecasting used to set rates. However, the OIC only refers to YEC and not AEY. Therefore, the Board questions whether the LTA attributed to AEY Fish Lake generation is to be included in the LTA calculations. Further, the LTA YEC applies to AEY's Fish Lake Generation is from Board Order 2014-06 and was a historical average before the replacement and upgrades of Fish Lake unit 1. The Board stated "Considering the long-term averages submitted by YECL and the lack of clarity respecting the efficiency gains related to the installation of new equipment, the Board for purposes of this application accepts the 8.73 GW.h annual generation output for the test period." The Board considers that the use of Fish Lake hydro (either as a LTA forecast, a GRA near term forecast or as an offset to YEC's wholesale sales) is an issue to be addressed by YEC in its next GRA."*

Prior to OIC 2021/16, as noted in the above reference to Board Order 2014/16, Yukon Energy GRAs have sought to apply LTA hydro generation for Fish Lake hydro when determining the wholesale firm purchases by AEY, applying the same LTA principles as Yukon Energy used to forecast its own hydro and thermal generation for GRA purposes. The Board approved this use of LTA for Fish Lake hydro generation when Yukon Energy GRA's provided for the use of LTA Fish Lake hydro in its filing.

Yukon Energy understands that OIC 2021/16 now requires the use of LTA for any renewable generation forecasts in a Yukon Energy GRA, and that this requirement includes the use of LTA for Fish Lake hydro forecasts used to forecast Yukon Energy wholesale sales requirements that directly impact the forecast of Yukon Energy forecast generation and related forecast thermal generation for test year revenue requirements.[1]

When dealing with the current and 2023/24 Yukon Energy GRAs, however, Yukon Energy completely understands the Board's need to clarify the use of LTA for Fish Lake Hydro as Yukon Energy also believes there is uncertainty regarding the updated LTA currently applicable for Fish Lake Hydro. When submitting the 2023/24 General Rate Application, Yukon Energy internally debated what the approved LTA for Fish Lake Hydro was. Yukon Energy noted that it is dependent on AEY to provide LTA estimates for Fish Lake hydro, and that at that time AEY had not provided any updates to the Fish Lake LTA.

As the Board has noted in Board Order 2025-08, the last approved Fish Lake LTA was from Board Order 2014-06. Section 3.2 Views of the Board stated, "Considering the long-term averages submitted by YECL and the lack of clarity respecting the efficiency gains related to the installation of new equipment, the Board for purposes of this application accepts the 8.73 GW.h annual generation output for the test period." In Board Order 2024-01, as part of AEY's 2023/24 GRA, the Board quoted Yukon Energy's comment in paragraph 35 "…YEC…concluded by stating that it forecasts Fish Lake hydro generation at 8.7 GWh for each test year equal to the long-term average (LTA), as required by OIC 2021/16." Board Order 2024-01 accepted a test-year Fish Lake forecast but made no mention of a change in Fish Lake LTA. Furthermore, during the AEY 2023/24 GRA it was disclosed that hydrogeneration in any particular year can be impacted by planned maintenance, water availability and adjusted for any planned decreases due to capital rebuilds.

In summary, Yukon Energy interpreted all the above in its 2023/24 GRA to mean that there has been no change in 'approved' LTA Fish Lake generation from the amount approved in Board Order 2014-06, notwithstanding ongoing changes affecting Fish Lake operation. This position was recognized in Appendix A to Board Order 2024-05 (paragraphs 38,39,40), and the Board in its approved wholesale forecast stated

[1] The OIC 2021/16 amendment to OIC 1995/90, in Section 9.1, subsection 3, directs that when the Board is determining forecast fuel costs for the forecast thermal generation needed to meet forecast customer requirements (per subsection 2) "...the Board must determine the forecast fuel costs for a financial year of Yukon Energy Corporation by (a) forecasting the amount of renewable generation available to contribute to meeting forecast customer requirements, based on long-term average annual renewable source availability; (b) forecasting the amount of thermal generation needed to meet any shortfall between the forecast renewable generation under paragraph (a) and forecast customer requirements."

(paragraph 47) "it is apparent that YEC does not have detailed LTA record of Fish Lake hydro" and that "AEY is the party best able to provide such a forecast and it is the AEY forecast for Fish Lake hydro that the Board accepts." As directed by Board Order 2024-05, Yukon Energy's Compliance Filing assumed the approved AEY wholesale purchase forecast (362.4 GWh for 2024) which assumed 10.1 GWh Fish Lake generation (Schedule 3.2 of AEY's Compliance Filing).

For purposes of calculating the revenue requirements for the 2025-2027 test years, Yukon Energy has continued (as in the final 2023/34 GRA Compliance filing approved by the Board) to assume wholesale forecasts as provided by AEY (see Tab 2, section 2.2.1). Yukon Energy has no new information today to assess separately any updated LTA for Fish Lake hydro, therefore, for this GRA purposes, no changes are assumed in the LTA for Fish Lake as approved by Board Order 2014-06.

APPENDIX 6.1
ENTERPRISE ASSET MANAGEMENT (EAM)/ PHYSICAL ASSET MANAGEMENT MANAGED SYSTEM (PAMMS) REPORTING

APPENDIX 6.1: ENTERPRISE ASSET MANAGEMENT (EAM)/PHYSICAL ASSET MANAGEMENT MANAGED SYSTEM (PAMMS) REPORTING

Board Order 2024-05, Appendix A, paragraph 270 directed Yukon Energy:

> "to provide reporting on the EAM/PAMMS project that quantifies; improvement in reliability measures; real cost benefits from inventory management; direct and real labour savings; measures that can show improvements in YEC's asset health; and any other measure that YEC can add that will help the Board and interested parties assess the overall benefit of this project."

Based on feedback from utilities in the Canadian Electricity Association (CEA),[1] quantifying qualitative benefits from implementing an asset management system can be challenging. Utilities do not start seeing these benefits immediately, but often a few years after implementation. The following steps are an example of how utilities can demonstrate value:

1. Identify key performance indicators;
2. Collect baseline data;
3. Monitor and analyze data; and
4. Calculate financial impact.

Industry research has generally shown that North American utilities are in different stages of their asset management journeys. Utilities' approaches to asset management reflect a number of factors, including the size and condition of their electrical systems and organizational objectives. Many southern utilities have had asset management systems in place for twenty years or more. Yukon Energy is at the beginning of its usage. The exact timeline of being able to calculate financial impact varies depending on the implementation strategy. Yukon Energy is implementing its asset management system in stages. Therefore, asset information will be different across the different asset classes. Yukon Energy is in the process of collecting and integrating baseline data, including data about asset age, condition and maintenance history. Yukon Energy will then spend years monitoring and analyzing data. After that, and only then, will actual financial impacts be able to be calculated.

[1] Yukon Energy participated in numerous CEA meetings and held discussions with colleagues from across the country.

The ‘measures’ that the Board requested to see in paragraph 270 of Order 2024-05 are challenging to answer directly. At this point in the lifecycle of asset management, Yukon Energy is not able to specifically quantify improvement in reliability measures since specific KPI’s have not been implemented to measure the projected improvements, nor does Yukon Energy have a baseline measure to compare to assess whether there are realized benefits. Yukon Energy is not able to provide quantitative real cost benefits from inventory management as warehousing has not yet been implemented. Direct and real labour savings correlate with a dependency on inventory management changes. Regarding measures that can show improvements in Yukon Energy’s asset health, Yukon Energy is just developing its baseline of data, so it is too early to calculate an improvement.

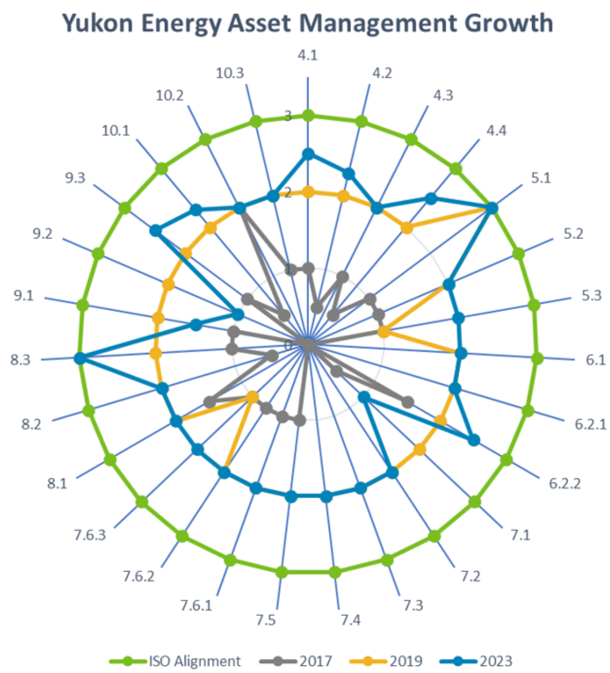
Therefore, at this early stage of the asset management lifecycle, Yukon Energy’s response to quantification of benefits is limited to ‘any other measure that YEC can add that will help the Board and interested parties assess the overall benefit of this project.’

The capital investment in the initial project to implement asset management is now complete (subject to more asset classes being added in the future). The foundation has been laid, and it is now up to Yukon Energy to grow and learn to use the tools that have been put into place. While Yukon Energy cannot monetize the value of improvement, below are some examples of where improvement can be seen:

1. **Maturity Assessment Improvement**

    a. Metsco provided an updated maturity assessment. An ISO55000 maturity assessment shows the alignment of the company’s asset management practices with ISO55000. An increase in maturity indicates more effective business practices, less waste and duplication of effort, and better alignment between team and corporate strategy.

        i. There is a measurable difference in maturity from the 2017 Hatch baseline maturity assessment to the 2023 assessment carried out by Metsco. The following chart shows the changes.



No	Clause
4.1	Understanding the organization and its context
4.2	Understanding the needs and expectations of stakeholders
4.3	Determining the scope of the asset management system
4.4	Asset management system
5.1	Leadership and commitment
5.2	Policy
5.3	Organizational roles, responsibilities and authorities
6.1	Actions to address risks and opportunities for the asset management system
6.2.1	Asset management objectives
6.2.2	Planning to achieve asset management objectives
7.1	Resources
7.2	Competence
7.3	Awareness
7.4	Communication
7.5	Information requirements
7.6.1	Documented information general
7.6.2	Creating and updating documented information
7.6.3	Control of documented information
8.1	Operational planning and control
8.2	Management of change
8.3	Outsourcing
9.1	Monitoring, measurement, analysis and evaluation
9.2	Internal audit
9.3	Management review
10.1	Nonconformity and corrective action
10.2	Preventive action
10.3	Continual improvement

ii. Improvement opportunities have been identified including a performance management framework and dashboard geared towards improvement in various areas.

b. Some of the improvement opportunities will take more time than others. Warehousing is a good example as it needs staffing and warehousing space to make a shift.

c. The foundational elements are there now, and next steps are to continue to make process and organizational improvements.

2. Asset Data Register

a. Yukon Energy now has a data register of assets that is accessible and useful. Operations work is being managed and tracked to those assets. Maintenance work is being planned and scheduled, and work is being tracked.

b. The asset register contains useful metadata helpful for developing asset management plans. For example, the Breakers Asset Management Plan references the loss of breakers with age and type from EAM, which is adequate for long term capital forecasting and for identifying near term priorities. In many instances of equipment, make, model and serial number are also tracked to support maintenance and capital planning.

c. Condition scoring is now functional in EAM (Yukon Energy has implemented Asset Health Index (AHI) scoring for SF6 breakers). However, since maintenance tests and data collection are carried out on a five-year cycle, it will take more years to fill in a full understanding of fleet condition. Yukon Energy plans to expand the program to other critical assets.

d. The asset register for substation assets contains criticality scoring for each asset. The criticality scoring will be used to prioritize capital and O&M decision making.

e. The register now contains 11,600 unique equipment items which Yukon Energy manages across generation, substation and T&D assets.

3. Asset Management Plan (AMP) Development

a. Asset management plans are now in place for several asset classes and will be updated and improved each year.

b. Asset management plans are aligning workload such as maintenance activities, capital replacement, and more specifically, the AH1 inspection.

c. Dam and Spillway AMPs align with dam safety inspection programs to prioritize dam and spillway investments to support capital planning and public safety.

d. AMPs provide an opportunity to align proactive maintenance activities with inspection data collection and capital planning – this provides the program structure and provides a strong basis for funding applications to government agencies to reduce the impact of major projects on ratepayers.

e. The maintenance activities agreed to internally by the different teams managing the equipment are documented in the AMP’s are implemented in EAM.

4. Capital Planning and Prioritization

a. A direct outcome of the asset management program was the development of a capital project prioritization and planning program.

b. The process engages leaders from across the organization to prioritize work for the entire company across all asset types.

c. This is the process used to develop the annual and five-year capital plans.

d. The planning process sees more engagement and buy in across the organization and is seen as productive and useful by our stakeholders in Yukon Development Corporation /Yukon government. Implementation of an asset management plan assisted Yukon Energy in receiving approval for funding and accessing Yukon government's debt cap.

e. Asset management is changing the conversation about the work that must be done and what the priorities are. Yukon Energy has a better picture of the work ahead than ever before.

5. Collaboration

a. The challenge of how to implement change and create alignment across Yukon Energy is driving collaboration between teams.

b. There is a new awareness of lifecycle cost vs project cost, and this is being used to support decision making for the long-term benefit of Yukon Energy (for example, comparing a cheaper used truck to a more expensive new one).

c. A cross departmental steering committee has formed to work through how to realize efficiency and process improvements as a team.

TAB 7
FINANCIAL SCHEDULES

Yukon Energy Corporation 2025-27 GRA
Compliance Filing

Schedule Index

Yukon Energy Corporation
Computation of Rate Base
($000s)

Schedule 1
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	**Property, Plant and Equipment**							
2	Year end balance	S.3 L.4	891,509	796,724	843,110	946,185	1,065,350	1,186,796
	Deduct:							
3	Accumulated depreciation (note 1)	S.3 L.8	238,671	224,234	239,951	260,608	285,136	312,792
4	Construction-in-progress	S.3 L.12	116,829	68,474	93,650	106,653	66,786	89,285
5	Disallowed assets	S.3 L.11	854	(141)	854	803	752	701
6	Miscellaneous reserves	S.3 L.17	1,751	2,148	83	679	1,276	1,872
7	Total deductions		358,105	294,716	334,538	368,743	353,949	404,651
	Add:							
8	Deferred Costs and Intangible Assets (note 2)	S.3 L.83	64,819	51,591	54,400	57,553	55,509	52,006
9	Less: Deferred Costs and Intangibles in Progress	S.3 L.84	38,780	32,881	26,959	12,565	13,388	5,093
10	Total additions		26,039	18,710	27,441	44,988	42,121	46,912
	Net plant in Service							
11	Current year-end balance	S.3 L.86	559,443	520,717	536,013	622,430	753,521	829,058
12	Previous year-end balance		519,440	478,861	520,717	536,013	622,430	753,521
13	Mid-year balance		539,441	499,789	528,365	579,222	687,976	791,290
14	Working capital	S.2 L.8	8,697	8,242	8,919	9,572	9,880	10,052
15	**Gross Rate Base**		548,138	508,031	537,284	588,794	697,856	801,341
	Deduct:							
	Contributions for extensions (PP&E)							
16	Current year-end balance		264,509	258,305	261,316	265,453	265,853	266,253
17	Contributions in WIP		26,516	18,337	12,933	16,670	170	170
18	Current year-end balance in-service		237,993	239,968	248,384	248,784	265,684	266,084
19	Accumulated amortization of contributions		63,971	59,327	64,785	71,926	79,486	87,466
20	Net current year-end balance in-service		174,022	180,642	183,599	176,857	186,197	178,618
21	Previous year-end balance		178,055	181,613	180,642	183,599	176,857	186,197
22	Mid-year balance		176,038	181,128	182,120	180,228	181,527	182,407
23	**Net Rate Base**	S.5 L.1	372,100	326,904	355,164	408,565	516,329	618,934

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
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	Operating and maintenance	S.5 L.5	54,096	48,623	54,810	61,667	66,076	69,135
2	Taxes other than income	S.5 L.6	777	756	759	771	790	806
3	Non-allowable expenses	S.5 L.12	(120)	(121)	(114)	(120)	(120)	(122)
4	Cash operating expenses		54,752	49,258	55,456	62,317	66,746	69,818
5	27/365		4,050	3,644	4,102	4,610	4,937	5,165
6	Inventory (three year average)		4,817	4,790	5,079	5,171	5,221	5,221
7	GST Impact on working capital	S.2A L.11	(170)	(191)	(262)	(209)	(278)	(334)
8	Working capital	S.1 L.14	8,697	8,242	8,919	9,572	9,880	10,052

Yukon Energy Corporation
Effect of GST on Working Capital
($000s)

Schedule 2A
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	Expenses subject to GST		139,615	97,303	91,817	159,554	161,358	163,401
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		6,981	4,865	4,591	7,978	8,068	8,170
4	Day Factor		14	14	14	14	14	14
5	Recoverable portion of GST impact		268	187	176	306	309	313
6	Revenue subject to GST		91,344	78,934	91,292	107,392	122,406	134,850
7	GST blended rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
8	GST payable		4,567	3,947	4,565	5,370	6,120	6,742
9	Day factor		35	35	35	35	35	35
10	Payable portion of GST impact		438	378	438	515	587	647
11	Net impact of GST on working capital	S.2 L.7	(170)	(191)	(262)	(209)	(278)	(334)

Yukon Energy Corporation **Schedule 3**
Continuity Schedule of Property, Plant and Equipment, Deferred Costs and Intangible Assets **2025-27 GRA**
($000s)

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
	Property, Plant and Equipment							
1	Balance at beginning of year		799,031	735,254	796,724	843,110	946,185	1,065,350
2	Net Increases to PPE (Table 5.1)		92,478	65,715	46,386	103,076	119,165	121,446
3	Retirements, disposals and adjustments		-	(4,245)	-	-	-	-
4	Balance at end of year	S.1 L.2	891,509	796,724	843,110	946,185	1,065,350	1,186,796
	Accumulated depreciation							
5	Balance at beginning of year		223,323	211,205	224,234	239,951	260,608	285,136
6	Depreciation expense	S.6 L.7	15,348	16,004	15,717	20,657	24,528	27,657
7	Retirements, disposals and adjustments		-	(2,975)	-	-	-	-
8	Balance at end of year	S.1 L.3	238,671	224,234	239,951	260,608	285,136	312,792
	Deductions from PP&E:							
9	Disallowed assets		1,388	1,388	1,388	1,388	1,388	1,388
10	Accum. Disallowed depreciation		(534)	(1,529)	(534)	(586)	(637)	(688)
11	Net Disallowed	S.1 L.5	854	(141)	854	803	752	701
12	Construction-in-progress	S.1 L.4	116,829	68,474	93,650	106,653	66,786	89,285
	Miscellaneous Reserves							
13	Fire Insurance Reserve		3,132	3,394	3,132	2,870	2,608	2,346
14	Reserve for Injuries and Damages		(3,347)	(3,282)	(5,086)	(4,577)	(4,069)	(3,560)
15	Reserve for Future Removal and Site Restoration		1,966	2,036	2,036	2,386	2,736	3,086
16	Total Miscellaneous Reserves	S.1 L.6	1,751	2,148	83	679	1,276	1,872
17	Total Deductions		119,434	70,482	94,587	108,135	68,814	91,858
18	Net Property, Plant and Equipment for Rate Base		533,403	502,007	508,572	577,442	711,401	782,146
	Add:							
19	Deferred study costs and Intangible assets (net of contributions)							
20	Feasibility Studies							
21	Opening balance		11,541	13,765	14,201	12,004	9,899	7,835
22	Additions		1,175	1,510	1,060	395	350	-
23	Amortization		(2,134)	(1,074)	(3,257)	(2,501)	(2,414)	(1,833)
24	Year-end balance		10,582	14,201	12,004	9,899	7,835	6,002
25	Feasibility Studies WIP		785	10,819	1,399	-	350	350
26	Relicensing							
27	Opening balance		26,961	17,089	22,917	26,867	29,515	29,084
28	Additions		7,327	6,648	4,762	4,113	1,450	905
29	Amortization		(812)	(820)	(812)	(1,465)	(1,881)	(2,075)
30	Year-end balance		33,476	22,917	26,867	29,515	29,084	27,914
31	Relicensing WIP		29,867	19,714	21,992	7,415	8,865	-
32	Dam Safety							
33	Opening balance		127	178	127	96	200	136
34	Additions		-	-	20	175	-	-
35	Amortization		(51)	(51)	(51)	(70)	(64)	(39)
36	Year-end balance		76	127	96	200	136	97
37	Dam Safety WIP		-	-	20	-	-	-
38	Vegetation Management Deferral							
39	Opening balance		665	886	665	443	222	(0)
40	Additions		-	-	-	-	-	-
41	Amortization		(222)	(222)	(222)	(222)	(222)	-
42	Year-end balance		443	665	443	222	(0)	(0)
43	Vegetation Management Deferral WIP		-	-	-	-	-	-

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
44	Intangibles							
45	Opening balance		9,840	4,582	4,424	4,916	4,916	6,068
46	Additions		4,830	568	1,210	1,985	2,042	816
47	Amortization		(1,281)	(726)	(718)	(833)	(914)	(976)
48	Year-end balance		13,389	4,424	4,916	6,068	6,044	5,907
49	Intangibles WIP		4,625	447	764	718	698	868
50	DSM							
51	Opening balance		1,857	1,121	1,510	1,933	2,350	2,428
52	Additions		1,160	520	644	747	484	444
53	Amortization		(255)	(131)	(220)	(331)	(405)	(454)
54	Year-end balance		2,762	1,510	1,933	2,350	2,428	2,419
55	DSM WIP		-	-	-	-	-	-
56	Regulatory							
57	Opening balance		2,684	6,097	7,807	8,139	9,298	9,979
58	Additions		1,600	1,901	1,015	1,855	1,375	400
59	Amortization		(131)	(190)	(684)	(696)	(694)	(715)
60	Year-end balance		4,154	7,807	8,139	9,298	9,979	9,664
61	Regulatory WIP		3,859	1,902	2,784	4,432	3,475	3,875
62	IPP Cost Deferral							
63	Opening balance		-	26	26	67	67	67
64	Additions		-	-	41	-	-	-
65	Amortization		-	-	-	-	-	-
66	Year-end balance		-	26	67	67	67	67
67	Defined Benefit Pension Deferral Account							
68	Opening balance		(62)	(62)	(87)	(65)	(65)	(65)
69	Additions		-	(24)	22	-	-	-
70	Amortization		-	-	-	-	-	-
71	Year-end balance		(62)	(87)	(65)	(65)	(65)	(65)
72	Total Deferred Costs and Intangible Assets							
73	Opening balance		53,613	43,681	51,591	54,400	56,401	55,533
74	Additions		16,092	11,122	8,774	9,270	5,701	2,565
75	Amortization		(4,885)	(3,213)	(5,964)	(6,117)	(6,593)	(6,092)
76	Year-end balance	S.1 L.8	64,819	51,591	54,400	57,553	55,509	52,006
77	Less: Deferred Costs and Intangible Assets in Progress	S.1 L.9	38,780	32,881	26,959	12,565	13,388	5,093
78	Total Net Deferred Costs and Intangible Assets for Rate Base		26,039	18,710	27,441	44,988	42,121	46,912
79	Total Net PP&E, Deferred Costs and Intangible Assets for Rate Base	S.1 L.11	559,443	520,717	536,013	622,430	753,521	829,058

Yukon Energy Corporation
Calculation of Depreciation Expense for 2025
$000

Schedule 3A - 2025
2025-27 GRA

Description	Cost at 2024 Year End	2025 Additions	2025 Disposals/ Adjustments	Cost at 2025 Year End	Approved Depreciation Rate (Years)	Depreciation Expense for 2025
A	B	C	D	E=B+C-D	F	G=B/F+C/2/F
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	78.4	0.0	1.6	76.9	50	1.6
Depreciation Study Differences						0.0
Total Land	**1,693.7**	**0.0**	**1.6**	**1,692.1**		**1.6**
Hydro Plant						
Structures and Improvements	54,670.3	8,119.1		62,789.3	72	815.7
Buildings and Improvements	10,278.7	0.0		10,278.7	40	257.0
Reservoirs, Dams, and Waterways	167,340.0	300.0	201.2	167,438.8	103	1,626.1
Hydro, Dams wtwys Twin Assets	6,711.4	0.0		6,711.4	103	65.2
Overhaul	13,677.7	0.0		13,677.7	10	1,367.8
Waterwheels,Turbines & Generation	28,222.8	0.0		28,222.8	85	332.0
Accessory Electric Equipment	27,401.1	0.0		27,401.1	40	685.0
Accessory Digital Equipment	858.7	0.0		858.7	20	42.9
Misc Power Plant Equipment	13,324.2	337.8		13,662.0	30	449.8
Fencing	107.1	0.0		107.1	30	3.6
Depreciation Study Differences						-140.3
Total Hydro Plant	**322,592.0**	**8,756.9**	**201.2**	**331,147.6**		**5,504.7**
Diesel Production						
Structures and Improvements	6,848.1	0.0		6,848.1	72	95.1
Buildings and Improvements	474.7	0.0		474.7	55	8.6
Fuel Holders, Products, and ACC	2,735.5	0.0		2,735.5	40	68.4
Generating Equipment and Prime	14,262.8	62,469.7	887.4	75,845.1	40	1,137.4
Overhaul	2,962.8	975.0		3,937.8	5	690.1
Minto Generating Equipment	243.5	0.0		243.5	12	20.3
Accessory Electric Equipment	9,041.0	0.0		9,041.0	45	200.9
Misc Power Plant Equipment	1,874.4	75.0		1,949.4	30	63.7
Depreciation Study Differences						-66.3
Total Diesel Production	**38,442.8**	**63,519.7**	**887.4**	**101,075.1**		**2,218.3**
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	83,695.1	713.0		84,408.1	65	1,293.1
Brushing	16,756.3	0.0		16,756.3	60	279.3
Survey Costs	4,297.2	0.0		4,297.2	60	71.6
Overhead Conductors / Poles	21,925.7	120.0		22,045.7	60	366.4
Overhead Conductors / Towers	278.0	0.0		278.0	60	4.6
Substation Equipment	75,796.1	850.8		76,646.8	54	1,411.5
Substation VGC Group - Gold Mine	10,688.6	0.0		10,688.6	10	1,068.9
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	162.0
Substation Fences	274.5	0.0		274.5	30	9.1
Depreciation Study Differences						-79.6
Total Main Transmission Facilities	**237,458.5**	**1,683.8**	**0.0**	**239,142.3**		**6,070.9**
Sub Transmission Lines						
Poles and Fixtures	4,640.1	0.0		4,640.1	65	71.4
25Kv Minto Spur- Structure	2,646.1	0.0		2,646.1	12	220.5
Brushing	41.6	0.0		41.6	60	0.7
Brushing Minto	432.5	0.0		432.5	12	36.0
Survey costs	0.0	0.0		0.0	60	0.0
Survey costs Minto	95.1	0.0		95.1	12	7.9
Overhead Conductors	1,837.9	0.0		1,837.9	60	30.6
Underground Conductors / Conduit	78.8	0.0		78.8	45	1.8
Overhead Conductors Minto	920.7	0.0		920.7	12	76.7
Substation Equipment	8,158.9	221.8		8,380.7	54	153.1
Substation Equipment Minto	7,111.2	0.0		7,111.2	12	592.6
Depreciation Study Differences						-36.4
Total Sub Transmission Lines	**25,963.1**	**221.8**	**0.0**	**26,184.8**		**1,155.1**
Distribution System						
Poles and Fixtures	19,847.7	2,182.7		22,030.4	40	523.5
Brushing	44.8	0.0		44.8	50	0.9
Survey costs	662.9	0.0		662.9	50	13.3
Overhead conductors - Poles	285.8	6,192.6		6,478.4	50	67.6
Overhead Costs	2,619.7	0.0		2,619.7	40	65.5
Underground Services	385.2	0.0		385.2	40	9.6
Underground Conduit	43.4	0.0		43.4	40	1.1

Yukon Energy Corporation
Calculation of Depreciation Expense for 2025
$000

Schedule 3A - 2025
2025-27 GRA

Description	Cost at 2024 Year End	2025 Additions	2025 Disposals/ Adjustments	Cost at 2025 Year End	Approved Depreciation Rate (Years)	Depreciation Expense for 2025
Wind Monitoring Equipment	0.0	0.0		0.0	0	0.0
Meters	312.6	0.0		312.6	16	19.5
Meter Equipment	288.4	0.0		288.4	16	18.0
Substation Equipment	2,202.1	0.0		2,202.1	40	55.1
Substation Buildings	64.8	0.0		64.8	55	1.2
Substation Fences	100.3	0.0		100.3	30	3.3
Street Lights	603.4	0.0		603.4	40	15.1
Line Transformers	4,042.5	0.0		4,042.5	35	115.5
Sentinel Lights	36.4	0.0		36.4	30	1.2
Depreciation Study Differences						50.0
Total Distribution System	**31,539.9**	**8,375.4**	**0.0**	**39,915.3**		**960.4**
Building and Other Equipment						
Survey Costs Land	4.3	0.0		4.3	50	0.1
Structures and Improvements (Hydro)	5,938.5	0.0		5,938.5	50	118.8
Building and Improvements	11,488.5	1,188.0		12,676.5	55	219.7
Office Furniture and Equipment	2,028.6	40.0		2,068.6	20	102.4
Communication Site Towers	19.3	0.0		19.3	40	0.5
Communication Site Fences	150.0	25.0		175.0	30	5.4
Computer Hardware	2,351.7	360.0		2,711.7	7	361.7
Computer Software	0.0	0.0		0.0	5	0.0
Tool and Instruments	3,707.2	678.7		4,385.9	20	202.3
Wind Monitoring Equipment	0.0	0.0		0.0	15	0.0
Communication Equipment	5,793.8	0.0		5,793.8	20	289.7
Company Owned Houses / Land	59.0	0.0		59.0	40	1.5
Company Owned Houses	2,152.4	0.0		2,152.4	40	53.8
Depreciation Study Differences						-67.3
Total Building and Other Equipment	**33,693.3**	**2,291.7**	**0.0**	**35,985.0**		**1,288.5**
Transportation						
Utility Vehicles	408.4	50.0		458.4	8	54.2
Sedans and Stationwagons	211.7	0.0		211.7	11	19.2
Trucks & Pole Trailer	71.8	0.0		71.8	25	2.9
Pole Trailers > 10,000 Lbs	53.7	0.0		53.7	25	2.1
Trucks 3/4 to 2 Ton	4,758.2	675.0		5,433.2	9	566.2
Trucks > 3 Ton	2,666.7	0.0		2,666.7	20	133.3
Foremost	1,003.9	0.0		1,003.9	20	50.2
Depreciation Study Differences						19.3
Total Transportation	**9,174.3**	**725.0**	**0.0**	**9,899.3**		**847.4**
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	220.0
Generator	20,891.0	0.0		20,891.0	40	522.3
Overhaul	1,692.1	2,080.2		3,772.4	2	1,366.1
Accessory Electric Equipment	3,655.9	0.0		3,655.9	45	81.2
Misc Power Plant Equipment	2,944.0	0.0		2,944.0	30	98.1
Fence	779.7	0.0		779.7	30	26.0
Depreciation Study Differences						-14.0
Total LNG Prodution	**49,348.1**	**2,080.2**	**0.0**	**51,428.4**		**2,385.7**
Battery Energy Storage						
Battery Energy Storage	0.0	0.0		0.0		0.0
Total Battery Energy Storage	**0.0**	**0.0**	**0.0**	**0.0**		**0.0**
Right of Use Assets						
Right of Use Assets	1,931.0	0.0		1,931.0		225.6
Total Right of Use Assets	**1,931.0**	**0.0**	**0.0**	**1,931.0**		**225.6**
Total	**753,002.3**	**87,654.4**	**1,090.2**	**839,566.5**		**20,658.1**

Yukon Energy Corporation Schedule 3A - 2026
Calculation of Depreciation Expense for 2026 2025-27 GRA
$000

Description	Cost at 2025 Year End	2026 Additions	2026 Disposals/ Adjustments	Cost at 2026 Year End	Approved Depreciation Rate (Years)	Depreciation Expense for 2026
A	B	C	D	E=B+C-D	F	G=B/F+C/2/F
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	76.9	0.0	1.5	75.3	50	1.5
Depreciation Study Differences						0.0
Total Land	**1,692.1**	**0.0**	**1.5**	**1,690.6**		**1.5**
Hydro Plant						
Structures and Improvements	62,789.3	109,763.2		172,552.5	72	1,634.3
Buildings and Improvements	10,278.7	0.0		10,278.7	40	257.0
Reservoirs, Dams, and Waterways	167,438.8	1,200.0		168,638.8	103	1,631.4
Hydro, Dams wtwys Twin Assets	6,711.4	0.0		6,711.4	103	65.2
Overhaul	13,677.7	0.0		13,677.7	10	1,367.8
Waterwheels,Turbines & Generation	28,222.8	0.0		28,222.8	85	332.0
Accessory Electric Equipment	27,401.1	0.0		27,401.1	40	685.0
Accessory Digital Equipment	858.7	0.0		858.7	20	42.9
Misc Power Plant Equipment	13,662.0	1,532.0		15,193.9	30	480.9
Fencing	107.1	0.0		107.1	30	3.6
Depreciation Study Differences						-140.3
Total Hydro Plant	**331,147.6**	**112,495.1**	**0.0**	**443,642.7**		**6,359.9**
Diesel Production						
Structures and Improvements	6,848.1	0.0		6,848.1	72	95.1
Buildings and Improvements	474.7	0.0		474.7	55	8.6
Fuel Holders, Products, and ACC	2,735.5	100.0		2,835.5	40	69.6
Generating Equipment and Prime	75,845.1	190.0		76,035.1	40	1,898.5
Overhaul	3,937.8	0.0		3,937.8	5	787.6
Minto Generating Equipment	243.5	0.0		243.5	12	20.3
Accessory Electric Equipment	9,041.0	0.0		9,041.0	45	200.9
Misc Power Plant Equipment	1,949.4	0.0		1,949.4	30	65.0
Depreciation Study Differences						-66.3
Total Diesel Production	**101,075.1**	**290.0**	**0.0**	**101,365.1**		**3,079.3**
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	84,408.1	300.0		84,708.1	65	1,300.9
Brushing	16,756.3	0.0		16,756.3	60	279.3
Survey Costs	4,297.2	100.0		4,397.2	60	72.5
Overhead Conductors / Poles	22,045.7	0.0		22,045.7	60	367.4
Overhead Conductors / Towers	278.0	0.0		278.0	60	4.6
Substation Equipment	76,646.8	2,030.0		78,676.8	54	1,438.2
Substation VGC Group - Gold Mine	10,688.6	0.0		10,688.6	10	1,068.9
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	162.0
Substation Fences	274.5	0.0		274.5	30	9.1
Depreciation Study Differences						-79.6
Total Main Transmission Facilities	**239,142.3**	**2,430.0**	**0.0**	**241,572.3**		**6,107.2**
Sub Transmission Lines						
Poles and Fixtures	4,640.1	0.0		4,640.1	65	71.4
25Kv Minto Spur- Structure	2,646.1	0.0		2,646.1	12	220.5
Brushing	41.6	0.0		41.6	60	0.7
Brushing Minto	432.5	0.0		432.5	12	36.0
Survey costs	0.0	0.0		0.0	60	0.0
Survey costs Minto	95.1	0.0		95.1	12	7.9
Overhead Conductors	1,837.9	0.0		1,837.9	60	30.6
Underground Conductors / Conduit	78.8	0.0		78.8	45	1.8
Overhead Conductors Minto	920.7	0.0		920.7	12	76.7
Substation Equipment	8,380.7	100.0		8,480.7	54	156.1
Substation Equipment Minto	7,111.2	0.0		7,111.2	12	592.6
Depreciation Study Differences						-36.4
Total Sub Transmission Lines	**26,184.8**	**100.0**	**0.0**	**26,284.8**		**1,158.0**
Distribution System						
Poles and Fixtures	22,030.4	2,380.5		24,410.9	40	580.5
Brushing	44.8	0.0		44.8	50	0.9
Survey costs	662.9	0.0		662.9	50	13.3
Overhead conductors - Poles	6,478.4	0.0		6,478.4	50	129.6
Overhead Costs	2,619.7	0.0		2,619.7	40	65.5
Underground Services	385.2	0.0		385.2	40	9.6
Underground Conduit	43.4	0.0		43.4	40	1.1

Yukon Energy Corporation
Calculation of Depreciation Expense for 2026
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Schedule 3A - 2026
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Description	Cost at 2025 Year End	2026 Additions	2026 Disposals/ Adjustments	Cost at 2026 Year End	Approved Depreciation Rate (Years)	Depreciation Expense for 2026
Wind Monitoring Equipment	0.0	0.0		0.0	0	0.0
Meters	312.6	0.0		312.6	16	19.5
Meter Equipment	288.4	0.0		288.4	16	18.0
Substation Equipment	2,202.1	0.0		2,202.1	40	55.1
Substation Buildings	64.8	0.0		64.8	55	1.2
Substation Fences	100.3	0.0		100.3	30	3.3
Street Lights	603.4	0.0		603.4	40	15.1
Line Transformers	4,042.5	0.0		4,042.5	35	115.5
Sentinel Lights	36.4	0.0		36.4	30	1.2
Depreciation Study Differences						50.0
Total Distribution System	**39,915.3**	**2,380.5**	**0.0**	**42,295.7**		**1,079.4**
Building and Other Equipment						
Survey Costs Land	4.3	0.0		4.3	50	0.1
Structures and Improvements (Hydro)	5,938.5	0.0		5,938.5	50	118.8
Building and Improvements	12,676.5	840.0		13,516.5	55	238.1
Office Furniture and Equipment	2,068.6	40.0		2,108.6	20	104.4
Communication Site Towers	19.3	0.0		19.3	40	0.5
Communication Site Fences	175.0	25.0		200.0	30	6.2
Computer Hardware	2,711.7	485.0		3,196.7	7	422.0
Computer Software	0.0	0.0		0.0	5	0.0
Tool and Instruments	4,385.9	1,230.0		5,615.9	20	250.0
Wind Monitoring Equipment	0.0	0.0		0.0	15	0.0
Communication Equipment	5,793.8	80.0		5,873.8	20	291.7
Company Owned Houses / Land	59.0	0.0		59.0	40	1.5
Company Owned Houses	2,152.4	0.0		2,152.4	40	53.8
Depreciation Study Differences						-67.3
Total Building and Other Equipment	**35,985.0**	**2,700.0**	**0.0**	**38,685.0**		**1,419.8**
Transportation						
Utility Vehicles	458.4	50.0		508.4	8	60.4
Sedans and Stationwagons	211.7	0.0		211.7	11	19.2
Trucks & Pole Trailer	71.8	0.0		71.8	25	2.9
Pole Trailers > 10,000 Lbs	53.7	0.0		53.7	25	2.1
Trucks 3/4 to 2 Ton	5,433.2	860.0		6,293.2	9	651.5
Trucks > 3 Ton	2,666.7	0.0		2,666.7	20	133.3
Foremost	1,003.9	0.0		1,003.9	20	50.2
Depreciation Study Differences						19.3
Total Transportation	**9,899.3**	**910.0**	**0.0**	**10,809.3**		**938.9**
Critical Spares						
Critical Spares	1,165.7	1,250.0		2,415.7	0	0.0
Total Critical Spares	**1,165.7**	**1,250.0**	**0.0**	**2,415.7**		**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	220.0
Generator	20,891.0	0.0		20,891.0	40	522.3
Overhaul	3,772.4	1,520.0		5,292.4	2	2,266.2
Accessory Electric Equipment	3,655.9	0.0		3,655.9	45	81.2
Misc Power Plant Equipment	2,944.0	0.0		2,944.0	30	98.1
Fence	779.7	0.0		779.7	30	26.0
Depreciation Study Differences						-14.0
Total LNG Prodution	**51,428.4**	**1,520.0**	**0.0**	**52,948.4**		**3,285.8**
Battery Energy Storage						
Battery Energy Storage	0.0	34,957.9		34,957.9	20	873.9
Total Battery Energy Storage	**0.0**	**34,957.9**	**0.0**	**34,957.9**		**873.9**
Right of Use Assets						
Right of Use Assets	1,931.0	0.0		1,931.0		225.6
Total Right of Use Assets	**1,931.0**	**0.0**	**0.0**	**1,931.0**		**225.6**
Total	**839,566.5**	**159,033.5**	**1.5**	**998,598.4**		**24,529.4**

Yukon Energy Corporation
Calculation of Depreciation Expense for 2027
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Schedule 3A - 2027
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Description	Cost at 2026 Year End	2027 Additions	2027 Disposals/ Adjustments	Cost at 2027 Year End	Approved Depreciation Rate (Years)	Depreciation Expense for 2027
A	B	C	D	E=B+C-D	F	G=B/F+C/2/F
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	75.3	0.0	1.5	73.8	50	1.5
Depreciation Study Differences						0.0
Total Land	**1,690.6**	**0.0**	**1.5**	**1,689.0**		**1.5**
Hydro Plant						
Structures and Improvements	172,552.5	75,224.1		247,776.6	72	2,919.0
Buildings and Improvements	10,278.7	400.0		10,678.7	40	262.0
Reservoirs, Dams, and Waterways	168,638.8	1,100.0		169,738.8	103	1,642.6
Hydro, Dams wtwys Twin Assets	6,711.4	0.0		6,711.4	103	65.2
Overhaul	13,677.7	2,050.0		15,727.7	10	1,470.3
Waterwheels,Turbines & Generation	28,222.8	0.0		28,222.8	85	332.0
Accessory Electric Equipment	27,401.1	460.0		27,861.1	40	690.8
Accessory Digital Equipment	858.7	0.0		858.7	20	42.9
Misc Power Plant Equipment	15,193.9	350.0		15,543.9	30	512.3
Fencing	107.1	0.0		107.1	30	3.6
Depreciation Study Differences						-140.3
Total Hydro Plant	**443,642.7**	**79,584.1**	**0.0**	**523,226.8**		**7,800.3**
Diesel Production						
Structures and Improvements	6,848.1	0.0		6,848.1	72	95.1
Buildings and Improvements	474.7	0.0		474.7	55	8.6
Fuel Holders, Products, and ACC	2,835.5	265.0		3,100.5	40	74.2
Generating Equipment and Prime	76,035.1	0.0		76,035.1	40	1,900.9
Overhaul	3,937.8	0.0		3,937.8	5	787.6
Minto Generating Equipment	243.5	0.0		243.5	12	20.3
Accessory Electric Equipment	9,041.0	0.0		9,041.0	45	200.9
Misc Power Plant Equipment	1,949.4	0.0		1,949.4	30	65.0
Depreciation Study Differences						-66.3
Total Diesel Production	**101,365.1**	**265.0**	**0.0**	**101,630.1**		**3,086.3**
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	84,708.1	6,700.1		91,408.2	65	1,354.7
Brushing	16,756.3	0.0		16,756.3	60	279.3
Survey Costs	4,397.2	100.0		4,497.2	60	74.1
Overhead Conductors / Poles	22,045.7	0.0		22,045.7	60	367.4
Overhead Conductors / Towers	278.0	0.0		278.0	60	4.6
Substation Equipment	78,676.8	2,200.0		80,876.8	54	1,477.3
Substation VGC Group - Gold Mine	10,688.6	0.0		10,688.6	10	1,068.9
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	162.0
Substation Fences	274.5	0.0		274.5	30	9.1
Depreciation Study Differences						-79.6
Total Main Transmission Facilities	**241,572.3**	**9,000.1**	**0.0**	**250,572.4**		**6,201.9**
Sub Transmission Lines						
Poles and Fixtures	4,640.1	0.0		4,640.1	65	71.4
25Kv Minto Spur- Structure	2,646.1	0.0		2,646.1	12	220.5
Brushing	41.6	0.0		41.6	60	0.7
Brushing Minto	432.5	0.0		432.5	12	36.0
Survey costs	0.0	0.0		0.0	60	0.0
Survey costs Minto	95.1	0.0		95.1	12	7.9
Overhead Conductors	1,837.9	0.0		1,837.9	60	30.6
Underground Conductors / Conduit	78.8	0.0		78.8	45	1.8
Overhead Conductors Minto	920.7	0.0		920.7	12	76.7
Substation Equipment	8,480.7	1,080.0		9,560.7	54	167.1
Substation Equipment Minto	7,111.2	0.0		7,111.2	12	592.6
Depreciation Study Differences						-36.4
Total Sub Transmission Lines	**26,284.8**	**1,080.0**	**0.0**	**27,364.8**		**1,169.0**
Distribution System						
Poles and Fixtures	24,410.9	1,974.9		26,385.8	40	635.0
Brushing	44.8	0.0		44.8	50	0.9
Survey costs	662.9	0.0		662.9	50	13.3
Overhead conductors - Poles	6,478.4	0.0		6,478.4	50	129.6
Overhead Costs	2,619.7	0.0		2,619.7	40	65.5
Underground Services	385.2	0.0		385.2	40	9.6
Underground Conduit	43.4	0.0		43.4	40	1.1

Yukon Energy Corporation
Calculation of Depreciation Expense for 2027
$000

Schedule 3A - 2027
2025-27 GRA

Description	Cost at 2026 Year End	2027 Additions	2027 Disposals/ Adjustments	Cost at 2027 Year End	Approved Depreciation Rate (Years)	Depreciation Expense for 2027
Wind Monitoring Equipment	0.0	0.0		0.0	0	0.0
Meters	312.6	0.0		312.6	16	19.5
Meter Equipment	288.4	700.0		988.4	16	39.9
Substation Equipment	2,202.1	0.0		2,202.1	40	55.1
Substation Buildings	64.8	0.0		64.8	55	1.2
Substation Fences	100.3	0.0		100.3	30	3.3
Street Lights	603.4	0.0		603.4	40	15.1
Line Transformers	4,042.5	0.0		4,042.5	35	115.5
Sentinel Lights	36.4	0.0		36.4	30	1.2
Depreciation Study Differences						50.0
Total Distribution System	**42,295.7**	**2,674.9**	**0.0**	**44,970.6**		**1,155.7**
Building and Other Equipment						
Survey Costs Land	4.3	0.0		4.3	50	0.1
Structures and Improvements (Hydro)	5,938.5	0.0		5,938.5	50	118.8
Building and Improvements	13,516.5	440.0		13,956.5	55	249.8
Office Furniture and Equipment	2,108.6	40.0		2,148.6	20	106.4
Communication Site Towers	19.3	0.0		19.3	40	0.5
Communication Site Fences	200.0	25.0		225.0	30	7.1
Computer Hardware	3,196.7	860.0		4,056.7	7	518.1
Computer Software	0.0	0.0		0.0	5	0.0
Tool and Instruments	5,615.9	695.0		6,310.9	20	298.2
Wind Monitoring Equipment	0.0	0.0		0.0	15	0.0
Communication Equipment	5,873.8	194.6		6,068.3	20	298.6
Company Owned Houses / Land	59.0	0.0		59.0	40	1.5
Company Owned Houses	2,152.4	0.0		2,152.4	40	53.8
Depreciation Study Differences						-67.3
Total Building and Other Equipment	**38,685.0**	**2,254.6**	**0.0**	**40,939.6**		**1,585.4**
Transportation						
Utility Vehicles	508.4	50.0		558.4	8	66.7
Sedans and Stationwagons	211.7	0.0		211.7	11	19.2
Trucks & Pole Trailer	71.8	0.0		71.8	25	2.9
Pole Trailers > 10,000 Lbs	53.7	0.0		53.7	25	2.1
Trucks 3/4 to 2 Ton	6,293.2	600.0		6,893.2	9	732.6
Trucks > 3 Ton	2,666.7	0.0		2,666.7	20	133.3
Foremost	1,003.9	0.0		1,003.9	20	50.2
Depreciation Study Differences						19.3
Total Transportation	**10,809.3**	**650.0**	**0.0**	**11,459.3**		**1,026.3**
Critical Spares						
Critical Spares	2,415.7	3,165.0		5,580.7	0	0.0
Total Critical Spares	**2,415.7**	**3,165.0**	**0.0**	**5,580.7**		**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	220.0
Generator	20,891.0	0.0		20,891.0	40	522.3
Overhaul	5,292.4	0.0		5,292.4	2	2,646.2
Accessory Electric Equipment	3,655.9	0.0		3,655.9	45	81.2
Misc Power Plant Equipment	2,944.0	275.0		3,219.0	30	102.7
Fence	779.7	0.0		779.7	30	26.0
Depreciation Study Differences						-14.0
Total LNG Prodution	**52,948.4**	**275.0**	**0.0**	**53,223.4**		**3,670.3**
Battery Energy Storage						
Battery Energy Storage	34,957.9	0.0		34,957.9	20	1,747.9
Total Battery Energy Storage	**34,957.9**	**0.0**	**0.0**	**34,957.9**		**1,747.9**
Right of Use Assets						
Right of Use Assets	1,931.0	0.0		1,931.0		213.8
Total Right of Use Assets	**1,931.0**	**0.0**	**0.0**	**1,931.0**		**213.8**
Total	**998,598.4**	**98,948.7**	**1.5**	**1,097,545.6**		**27,658.3**

YUKON ENERGY CORPORATION — **Schedule 3B - 2025**

Calculation of Amortization Expense for Deferred Costs and Intangibles (2025) — **2025-27 GRA**

$000

	Total Expenditures				NBV			
	Dec 31 2024	2025 Forecast Additions	2025 Forecast Transfers /Retired	Dec 31 2025	Dec 31 2024	Amortization Period	2025 Forecast Expenses	
Feasibility Study								
Completed Projects:								
Gladstone	4,521			4,521	904	10	452	
Mayo & Aishihik Climate Change	667			667	78	5	78	
Elevator Study Aishik	6			6	1	5	1	
Radio Repeater Assessment	25			25	5	5	5	
Transmission Line Access Plan	88			88	18	5	18	
Mt Sumanik Wind Feasibility St	744			744	149	5	149	
Mayo Earthworks	90			90	25	5	18	
FD7 Condition Assessment	73			73	28	5	15	
Wareham Spillgate Leakage Reduction	53			53	21	5	11	
P125 Intake Trash Rack Cleaning System	59			59	24	5	12	
PMF Flood Study	78			78	27	5	16	
IPP SOP Implentation	326			326	130	5	65	
WH Post-Flood Assessment	115			115	61	5	23	
Emergency Preparedness Improvement	60			60	36	5	12	
P126 Building Renovation	196			196	118	5	39	
WH4 Low Water Cavitation Study & Recommendation	47			47	27	5	9	
Southern Lakes Enhanced Storage	8,784			8,784	6,881	10	878	
Thermal SG4 WH Gas Feasibility	122			122	73	5	24	
Emission/Thermal Allocation Study	36			36	29	5	7	
Mayo Civil Infrastructure Refurbishment Planning	173			173	138	5	35	
SCADA/Server Room Fire Assessment	11			11	9	5	2	
Building Condition Reports	137			137	109	5	27	
Transformer Containment/Spill Risk Study	25			25	20	5	5	
Mayo Lake/Wareham Dam Breach	68			68	54	5	14	
IPP Power Variability Study	66			66	53	5	13	
IPP Technical Interconnection	13			13	11	5	3	
Climate Change Adaptation	44			44	43	5	9	
Thermal Plant Replacement Project	869			869	695	5	174	
ERP Requirements Gathering	118			118	95	5	24	
Mayo Lake CS/Wareham Dam Seismic Assmnt	100			100	100	5	20	
Lewes Gate/Seal Refurbishment	159			159	159	5	32	
Wareham Dam Toe Seepage Analysis	29			29	29	5	6	
Mayo Civil Project Feasibiltiy Study	201			201	201	5	40	
Wareham Winter Spill Study	122			122	122	5	24	
Transmssion Line Corridor Heritage Assmnt	20			20	20	5	4	
Aishihik Intake Inspection	158			158	158	5	32	
Lease Options Analysis 2024	9			9	9	5	2	
System Fire Suppression Assessment Study	66			66	66	5	13	
T&D Emrgncy Spare Parts & Stocking Study	14			14	14	5	3	
S170 McIntyre P&C & SCADA Upgrade DBM	19			19	19	5	4	
S250 Callison System Preliminary Engineering	29			29	29	5	6	
System Wide Arc Flash Study		245		245	-	5	24	
System Wide Stability Study		152		152	-	5	15	
SDIC Program Development		2		2	-	5	0	
AGS Fish Passage Study		3		3	-	5	0	
Project Management Software Research		123		123	-	5	12	
T&D Load Planning Study		164		164	-	5	16	
Business Continuity Plan		101		101	-	5	10	
YEC Process Refinement		69		69	-	5	7	
SF6 Dead Tank Breaker Monitoring - develop solution		18		18	-	5	2	
Condition Assessment for Critical Power Transformers and Reactors		307		307	-	5	31	
WG0 Summer High Temp Investigation		48		48	-	5	5	
Aishihik Dam Breach Study		13		13	-	5	1	
Grid Modernization Study		105		105	-	5	10	
WH Updated Slope Stability Assessment		4		4	-	5	0	
System Fire Protection Assessment		146		146	-	5	15	
Dam Safety Program High Risk		351		351	-	5	35	
Renewable Diesel Pilot Project		5		5	-	5	1	
Grid Modernization Study Contributions		(63)		(63)	-	5	(6)	
Total Feasibility Study Closed	18,537	1,794	-	20,331	10,785		2,501	
Regulatory								
Completed Projects:								
DSM	5,768	747	-	6,515	3,839	10	614	
DSM Contributions	(2,924)			(2,924)	(1,906)	10	(292)	
YUB 2007-8 - Part 3 Hearing	185			185	115	45	4	
10 Year Renewable Energy Plan	634			634	127	5	127	
Asset Management Framework	5,533			5,533	4,979	10	553	
Customer Bill Structure		207		207	-	5	21	
Total Regulatory Closed	9,196	954	-	10,151	7,154		1,027	
Relicensing								
Completed Projects:								
Aishihik 2022 5 Year Relicensing	3,903	714		4,618	2,342	5	852	
Whitehorse Hatchery Water Relicensing	40			40	31	25	2	
Whitehorse Relicensing	132			132	6	License term	6	*
Whitehorse Relicensing		10,608		10,608	-	25	212	
Mayo Relicensing	129			129	11	License term	11	*
Mayo Relicensing		7,295		7,295	-	25	146	
Thermal Assessment & Permitting	216			216	216	25	9	
Dawson City Air Emissions Permit		14		14	-	25	0	
Mayo Air Emissions Permit		10		10	-	25	0	
Aishihik and Takhini Substation Thermal Assessment and Permitting		50		50	-	25	1	
Mayo Lake Enhanced Storage	2,267			2,267	2,267	10	227	
Total Relicensing Closed	6,688	18,691	-	25,378	4,874		1,466	
Dam Safety Review								
Completed projects	254	195		449	76	5	70	
Deferred Vegetation Management							222	
Total Deferred Costs	**34,675**	**21,634**	**0**	**56,309**	**22,889**		**5,285**	
Intangibles								
Completed Projects:								
Financial Software Costs	2,836			2,836	109	10	(0)	**
Other intangible	2,077	2,031		4,108	1,312		378	**
EAM Purchase and Implementation	4,550			4,550	2,730	10	455	
Total Intangibles Closed	9,464	2,031	-	11,494	4,151		833	
Total Deferred and Intangibles Closed	**44,139**	**23,665**	**0**	**67,804**	**27,041**		**6,118**	

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

* The licensing cost amortization reflects the amortization of a number of licensing related projects [fishiries, control structure, salmon enhancement, etc.] over the years with amortization period ending 2025 [the current water use licence term].
** Includes a number of small projects.

YUKON ENERGY CORPORATION **Schedule 3B - 2026**
Calculation of Amortization Expense for Deferred Costs and Intangibles (2026) **2025-27 GRA**
$000

	Total Expenditures				NBV		
	Dec 31 2025	2026 Forecast Additions	Transfers /Retired	Dec 31 2026	Dec 31 2025	Amortization Period	2026 Forecast Expenses
Feasibility Study							
Completed Projects:							
Gladstone	4,521			4,521	452	10	452
Mayo Earthworks	90			90	7	5	7
FD7 Condition Assessment	73			73	13	5	13
Wareham Spillgate Leakage Reduction	53			53	11	5	11
P125 Intake Trash Rack Cleaning System	59			59	12	5	12
PMF Flood Study	78			78	12	5	12
IPP SOP Implentation	326			326	65	5	65
WH Post-Flood Assessment	115			115	38	5	23
Emergency Preparedness Improvement	60			60	24	5	12
P126 Building Renovation	196			196	79	5	39
WH4 Low Water Cavitation Study & Recommendation	47			47	18	5	9
Southern Lakes Enhanced Storage	8,784			8,784	6,002	10	878
Thermal SG4 WH Gas Feasibility	122			122	49	5	24
Emission/Thermal Allocation Study	36			36	22	5	7
Mayo Civil Infrastructure Refurbishment Planning	173			173	104	5	35
SCADA/Server Room Fire Assessment	11			11	7	5	2
Building Condition Reports	137			137	82	5	27
Transformer Containment/Spill Risk Study	25			25	15	5	5
Mayo Lake/Wareham Dam Breach	68			68	41	5	14
IPP Power Variability Study	66			66	40	5	13
IPP Technical Interconnection	13			13	8	5	3
Climate Change Adaptation	44			44	34	5	9
Thermal Plant Replacement Project	869			869	521	5	174
ERP Requirements Gathering	118			118	71	5	24
Mayo Lake CS/Wareham Dam Seismic Assmnt	100			100	80	5	20
Lewes Gate/Seal Refurbishment	159			159	127	5	32
Wareham Dam Toe Seepage Analysis	29			29	23	5	6
Mayo Civil Project Feasibiltiy Study	201			201	161	5	40
Wareham Winter Spill Study	122			122	98	5	24
Transmssion Line Corridor Heritage Assmnt	20			20	16	5	4
Aishihik Intake Inspection	158			158	126	5	32
Lease Options Analysis 2024	9			9	7	5	2
System Fire Suppression Assessment Study	66			66	53	5	13
T&D Emrgncy Spare Parts & Stocking Study	14			14	11	5	3
S170 McIntyre P&C & SCADA Upgrade DBM	19			19	15	5	4
S250 Callison System Preliminary Engineering	29			29	23	5	6
System Wide Arc Flash Study	245			245	220	5	49
System Wide Stability Study	152			152	137	5	30
SDIC Program Development	2			2	2	5	0
AGS Fish Passage Study	3			3	3	5	1
Project Management Software Research	123			123	111	5	25
T&D Load Planning Study	164			164	148	5	33
Business Continuity Plan	101			101	91	5	20
YEC Process Refinement	69			69	62	5	14
SF6 Dead Tank Breaker Monitoring - develop solution	18			18	17	5	4
Condition Assessment for Critical Power Transformers an	307			307	276	5	61
WG0 Summer High Temp Investigation	48			48	44	5	10
Aishihik Dam Breach Study	13			13	11	5	3
Grid Modernization Study	105			105	94	5	21
WH Updated Slope Stability Assessment	4			4	4	5	1
System Fire Protection Assessment	146			146	132	5	29
Dam Safety Program High Risk	351			351	316	5	70
Renewable Diesel Pilot Project	5			5	5	5	1
Grid Modernization Study Contributions	(63)			(63)	(56)	5	(13)
Total Feasibility Study Closed	18,802	-	-	18,802	10,078		2,414
Regulatory							
Completed Projects:							
DSM	6,515	484	-	6,999	3,972	10	676
DSM Contributions	(2,924)			(2,924)	(1,614)	10	(292)
YUB 2007-8 - Part 3 Hearing	185			185	111	45	4
Asset Management Framework	5,533			5,533	4,426	10	553
Customer Bill Structure	207			207	187	5	41
Integrated Resource Plan		2,332		2,332	-	10	117
Total Regulatory Closed	9,517	2,816	-	12,332	7,082		1,099
Relicensing							
Completed Projects:							
Aishihik 2022 5 Year Relicensing	4,618			4,618	2,204	5	924
Whitehorse Hatchery Water Relicensing	40			40	30	25	2
Whitehorse Relicensing	10,608			10,608	10,396	25	424
Mayo Relicensing	7,295			7,295	7,149	25	292
Thermal Assessment & Permitting	216			216	208	25	9
Dawson City Air Emissions Permit	14			14	14	25	1
Mayo Air Emissions Permit	10			10	10	25	0
Aishihik and Takhini Substation Thermal Assessment and	50			50	49	25	2
Mayo Lake Enhanced Storage	2,267			2,267	2,040	10	227
Total Relicensing Closed	25,118	-	-	25,118	22,099		1,880
Dam Safety Review							
Completed projects	449			449	200	5	64
Deferred Vegetation Management							222
Total Deferred Costs	**53,886**	**2,816**	**0**	**56,701**	**39,460**		**5,678**
Intangibles							
Completed Projects:							
Financial Software Costs	2,836			2,836	109	10	(0) **
Other intangible	4,108	910		5,018	2,965		459 **
EAM Purchase and Implementation	4,550			4,550	2,275	10	455
Total Intangibles Closed	11,494	910	-	12,404	5,349		914
Total Deferred and Intangibles Closed	**65,380**	**3,726**	**0**	**69,105**	**44,808**		**6,592**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

* The licensing cost amortization reflects the amortization of a number of licensing related projects [fishiries, control structure, salmon enhancement, etc.] over the years with amortization period ending 2025 [the current water use licence term].
** Includes a number of small projects.

YUKON ENERGY CORPORATION — **Schedule 3B - 2027**
Calculation of Amortization Expense for Deferred Costs and Intangibles (2027) — **2025-27 GRA**
$000

	Total Expenditures				NBV			
	Dec 31 2026	2027 Forecast Additions	2027 Forecast Transfers /Retired	Dec 31 2027	Dec 31 2026	Amortization Period	2027 Forecast Expenses	
Feasibility Study								
Completed Projects:								
WH Post-Flood Assessment	115			115	15	5	15	
Emergency Preparedness Improvement	60			60	12	5	12	
P126 Building Renovation	196			196	39	5	39	
WH4 Low Water Cavitation Study & Recommendation	47			47	9	5	9	
Southern Lakes Enhanced Storage	8,784			8,784	5,124	10	878	
Thermal SG4 WH Gas Feasibility	122			122	24	5	24	
Emission/Thermal Allocation Study	36			36	14	5	7	
Mayo Civil Infrastructure Refurbishment Planning	173			173	69	5	35	
SCADA/Server Room Fire Assessment	11			11	4	5	2	
Building Condition Reports	137			137	55	5	27	
Transformer Containment/Spill Risk Study	25			25	10	5	5	
Mayo Lake/Wareham Dam Breach	68			68	27	5	14	
IPP Power Variability Study	66			66	26	5	13	
IPP Technical Interconnection	13			13	5	5	3	
Climate Change Adaptation	44			44	25	5	9	
Thermal Plant Replacement Project	869			869	348	5	174	
ERP Requirements Gathering	118			118	47	5	24	
Mayo Lake CS/Wareham Dam Seismic Assmnt	100			100	60	5	20	
Lewes Gate/Seal Refurbishment	159			159	95	5	32	
Wareham Dam Toe Seepage Analysis	29			29	17	5	6	
Mayo Civil Project Feasibiltiy Study	201			201	120	5	40	
Wareham Winter Spill Study	122			122	73	5	24	
Transmssion Line Corridor Heritage Assmnt	20			20	12	5	4	
Aishihik Intake Inspection	158			158	95	5	32	
Lease Options Analysis 2024	9			9	5	5	2	
System Fire Suppression Assessment Study	66			66	40	5	13	
T&D Emrgncy Spare Parts & Stocking Study	14			14	8	5	3	
S170 McIntyre P&C & SCADA Upgrade DBM	19			19	11	5	4	
S250 Callison System Preliminary Engineering	29			29	17	5	6	
System Wide Arc Flash Study	245			245	171	5	49	
System Wide Stability Study	152			152	106	5	30	
SDIC Program Development	2			2	1	5	0	
AGS Fish Passage Study	3			3	2	5	1	
Project Management Software Research	123			123	86	5	25	
T&D Load Planning Study	164			164	115	5	33	
Business Continuity Plan	101			101	71	5	20	
YEC Process Refinement	69			69	48	5	14	
SF6 Dead Tank Breaker Monitoring - develop solution	18			18	13	5	4	
Condition Assessment for Critical Power Transformers an	307			307	215	5	61	
WG0 Summer High Temp Investigation	48			48	34	5	10	
Aishihik Dam Breach Study	13			13	9	5	3	
Grid Modernization Study	105			105	73	5	21	
WH Updated Slope Stability Assessment	4			4	3	5	1	
System Fire Protection Assessment	146			146	102	5	29	
Dam Safety Program High Risk	351			351	246	5	70	
Renewable Diesel Pilot Project	5			5	4	5	1	
Grid Modernization Study Contributions	(63)			(63)	(44)	5	(13)	
Total Feasibility Study Closed	13,602	-	-	13,602	7,665		1,833	
Regulatory								
Completed Projects:								
DSM	6,999	444	-	7,443	3,780	10	535	
DSM Contributions	(2,924)			(2,924)	(1,321)	10	(199)	
YUB 2007-8 - Part 3 Hearing	185			185	107	45	4	
Asset Management Framework	5,533			5,533	3,873	10	553	
Customer Bill Structure	207			207	145	5	41	
Integrated Resource Plan	2,332			2,332	2,215	10	233	
Total Regulatory Closed	12,332	444	-	12,776	8,799		1,168	
Relicensing								
Completed Projects:								
Aishihik 2022 5 Year Relicensing	4,618			4,618	1,281	5	924	
Whitehorse Hatchery Water Relicensing	40			40	28	25	2	
Whitehorse Relicensing	10,608			10,608	9,971	25	424	
Mayo Relicensing	7,295			7,295	6,857	25	292	
Thermal Assessment & Permitting	216			216	199	25	9	
Dawson City Air Emissions Permit	14			14	13	25	1	
Mayo Air Emissions Permit	10			10	9	25	0	
Aishihik and Takhini Substation Thermal Assessment and	50			50	47	25	2	
Mayo Lake Enhanced Storage	2,267			2,267	1,814	10	227	
Aishihik 25-Year Water Use License Renewal		9,770		9,770	-	25	195	
Total Relicensing Closed	25,118	9,770	-	34,887	20,219		2,075	
Dam Safety Review								
Completed projects	449			449	136	5	39	
Total Deferred Costs	**51,502**	**10,214**	**0**	**61,715**	**36,819**		**5,116**	
Intangibles								
Completed Projects:								
Financial Software Costs	2,836			2,836	109	10	(0)	**
Other intangible	5,018	670		5,688	3,416		521	**
EAM Purchase and Implementation	4,550			4,550	1,820	10	455	
Total Intangibles Closed	12,404	670	-	13,074	5,344		976	
Total Deferred and Intangibles Closed	**63,906**	**10,884**	**0**	**74,790**	**42,163**		**6,092**	

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

* The licensing cost amortization reflects the amortization of a number of licensing related projects [fishiries, control structure, salmon enhancement, etc.] over the years with amortization period ending 2025 [the current water use licence term].
** Includes a number of small projects.

Yukon Energy Corporation
Cost of Capital Calculation
($000s)

Schedule 4
2025-27 GRA

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Deemed Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
	2024 GRA Compliance							
1	Long-Term debt	S.11 L.19	223,115	60.0%	60.0%	223,260	3.43%	7,654
2	Common Stock		148,487	40.0%	40.0%	148,840	9.15%	13,619
3	Total	S.5 L.3	371,602	100.0%	100.0%	372,100	5.72%	21,273
	2023 Actual							
4	Long-Term debt	S.11 L.19	188,025	57.5%		188,101	3.13%	5,888
5	Common Stock		138,746	42.5%		138,803	7.04%	9,776
6	Total	S.5 L.3	326,771	100.0%		326,904	4.79%	15,664
	2024 Preliminary Actual							
7	Long-Term debt	S.11 L.19	198,511	59.4%		210,801	3.15%	6,640
8	Common Stock		135,946	40.6%		144,363	7.89%	11,393
9	Total	S.5 L.3	334,458	100.0%		355,164	5.08%	18,033
	Forecast 2025							
10	Long-Term debt	S.11 L.19	240,873	59.7%	60.0%	243,777	3.56%	8,672
11	Common Stock		162,826	40.3%	40.0%	164,789	9.15%	15,078
12	Total	S.5 L.3	403,699	100.0%	100.0%	408,565	5.81%	23,751
	Forecast 2026							
13	Long-Term debt	S.11 L.19	309,705	60.0%	60.0%	309,798	3.72%	11,510
14	Common Stock		206,469	40.0%	40.0%	206,531	9.15%	18,898
15	Total	S.5 L.3	516,174	100.0%	100.0%	516,329	5.89%	30,408
	Forecast 2027							
16	Long-Term debt	S.11 L.19	371,309	60.0%	60.0%	371,361	4.02%	14,918
17	Common Stock		247,539	40.0%	40.0%	247,573	9.15%	22,653
18	Total	S.5 L.3	618,848	100.0%	100.0%	618,934	6.07%	37,571

Yukon Energy Corporation
Utility Revenue Requirement
($000s)

Schedule 5
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	Net rate base	S.1 L.23	372,100	326,904	355,164	408,565	516,329	618,934
2	Average Rate of return on rate base		5.72%	4.79%	5.08%	5.81%	5.89%	6.07%
3	Utility income	S.8 L.1	21,273	15,664	18,033	23,751	30,408	37,571
4	Utility expenses							
5	Operating and maintenance (note 1)	S.6 L.3	54,096	48,623	54,810	61,667	66,076	69,135
6	Taxes other than income	S.6 L.4	777	756	759	771	790	806
7	Amortization of deferred costs	S.6 L.5	5,345	3,690	5,436	7,006	7,488	6,893
8	Reserve for Injuries and Damages	S.6 L.6	616	616	616	1,063	1,063	1,063
9	Depreciation	S.6 L.7	15,350	16,005	15,719	21,008	24,879	28,008
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(5,941)	(6,742)	(5,967)	(7,702)	(8,127)	(8,453)
11	Disallowed depreciation		(51)	(51)	(51)	(51)	(51)	(51)
12	Donations		(120)	(121)	(114)	(120)	(120)	(122)
13	Total utility expenses		70,071	62,776	71,208	83,641	91,998	97,278
14	Revenue Requirement	S.6 L.1	91,344	78,440	89,241	107,392	122,406	134,850

Note 1: Includes fuel expenses and purchased power.

Yukon Energy Corporation
Statement of Earnings
($000s)

Schedule 6
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	Revenues (note 1)	S.5 L.14	91,344	78,440	89,242	107,392	122,406	134,850
2	**Operating expenses**							
3	Operating and maintenance	S.10 L.15	54,096	48,623	54,810	61,667	66,076	69,135
4	Taxes other than income	S.5 L.6	777	756	759	771	790	806
5	Amortize deferred costs		5,345	3,690	5,436	7,006	7,488	6,893
6	Reserve for Injuries and Damages	S.5 L.8	616	616	616	1,063	1,063	1,063
7	Depreciation		15,350	16,005	15,719	21,008	24,879	28,008
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(5,941)	(6,742)	(5,967)	(7,702)	(8,127)	(8,453)
9	Total		70,242	62,948	71,373	83,812	92,169	97,452
10	**Operating income**		21,102	15,492	17,869	23,579	30,237	37,398
11	**Other income**							
12	Allowed for Funds Used	S.8 L.2	3,354	1,840	2,733	3,735	3,805	3,254
13	Miscellaneous (note 2)	S.8 L.3	(3,126)	(1,223)	(5,297)	(3,586)	(4,472)	(4,999)
14	Total		228	617	(2,563)	149	(667)	(1,745)
15	**Other expenses**							
16	Interest expense	S.8 L.4	10,157	9,479	10,958	10,814	12,279	14,241
17	Total		10,157	9,479	10,958	10,814	12,279	14,241
18	**Net earnings**	S.8 L.8	11,172	6,630	4,348	12,914	17,291	21,412

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
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	Balance at beginning of year		84,615	94,226	73,330	78,027	78,027	90,941
	Add:							
2	Net earnings	S.6 L.18	11,172	6,630	4,348	12,914	17,291	21,412
3	IFRS Comprehensive Income Adjustment			(267)	350	-	-	-
4	Balance at end of year before dividend		95,788	100,590	78,027	90,941	95,319	112,354
	Less:							
5	Common Dividends (note 1)		-	27,260	-	-	-	-
6	Balance at end of year		95,788	73,330	78,027	90,941	95,319	112,354
	Shareholder's Equity							
7	Common shares		61,603	54,968	65,568	91,117	122,649	134,552
8	Retained earnings		95,788	73,330	78,027	90,941	95,319	112,354
9	Total		157,390	128,298	143,595	182,059	217,968	246,906

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
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	Utility Income (Return on Rate Base)	S.5 L.3	21,273	15,664	18,033	23,751	30,408	37,571
	Add:							
2	Allowance for funds used	S.6 L.12	3,354	1,840	2,733	3,735	3,805	3,254
3	Other income (expenses)	S.6 L.13	(3,126)	(1,223)	(5,297)	(3,586)	(4,472)	(4,999)
			21,501	16,281	15,470	23,899	29,741	35,826
	Less:							
4	Interest - long-term	S.6 L.17	10,157	9,479	10,958	10,814	12,279	14,241
5	Donations	S.5 L.12	120	121	114	120	120	122
6	Disallowed costs		-	-	-	-	-	-
7	Disallowed depreciation	S.5 L.11	51	51	51	51	51	51
			10,329	9,651	11,123	10,985	12,450	14,414
8	Net earnings	S.6 L.18	11,172	6,630	4,347	12,914	17,291	21,412

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues
($000s)

Schedule 9
2025-27 GRA

Line No.	Description	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	**Residential**						
2	Customers	1,898	1,889	1,968	2,008	2,048	2,088
3	Sales in MWh	18,090	17,328	18,989	19,369	19,756	20,151
4	MWh sales per customer	9.5	9.2	9.6	9.6	9.6	9.6
5	Revenue ($000s)	2,611	2,472	2,749	2,823	2,879	2,937
6	Cents per KWh	14.4	14.3	14.5	14.6	14.6	14.6
7	**General Service**						
8	Customers	536	561	612	618	624	630
9	Sales in MWh	44,698	39,502	39,520	39,781	40,044	40,310
10	MWh sales per customer	83.4	70.5	64.6	64.3	64.1	64.0
11	Revenue ($000s)	7,175	6,476	6,860	6,496	6,539	6,583
12	Cents per KWh	16.1	16.4	17.4	16.3	16.3	16.3
13	**Industrial**						
14	Sales in MWh	69,368	74,498	46,127	42,796	42,796	42,796
15	Revenue ($000s)	8,809	9,586	6,888	5,724	5,628	5,628
16	Cents per KWh	12.7	12.9	14.9	13.4	13.2	13.2
17	**Street lights**						
18	Sales in MWh	168	168	172	171	171	171
19	Revenue ($000s)	82	83	83	83	83	83
20	Cents per KWh	48.9	49.4	48.3	48.6	48.6	48.6
21	**Space lights**						
22	Sales in MWh	9	9	10	10	10	10
23	Revenue ($000s)	2	3	3	3	3	3
24	Cents per KWh	27.3	29.2	26.5	26.9	26.9	26.9
25	**Total Company - Firm Retail and Industrial**						
26	Customers	2,434	2,450	2,580	2,626	2,672	2,718
27	Sales in MWh	132,333	131,504	104,818	102,127	102,777	103,439
28	Revenue ($000s)	18,679	18,619	16,582	15,128	15,132	15,234
29	Cents per KWh	14.1	14.2	15.8	14.8	14.7	14.7
30	**Wholesale sales**						
31	Sales in MWh	362,365	347,704	374,831	373,662	381,929	390,420
32	Revenue ($000s)	30,069	28,852	31,103	31,006	31,692	32,397
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3	8.3
34	**Total Company - Firm**						
35	Sales in MWh	494,699	479,208	479,649	475,788	484,706	493,858
36	Revenue ($000s)	48,748	47,471	47,685	46,135	46,824	47,631
37	Cents per KWh	9.9	9.9	9.9	9.7	9.7	9.6
38	**Secondary**						
39	Sales in MWh	2,931	2,214	3,699	2,931	2,931	2,931
40	Revenue ($000s)	358	227	379	287	287	287
41	Cents per KWh	12.2	10.2	10.2	9.8	9.8	9.8
42	**Total Company**						
43	Sales in MWh	497,630	481,422	483,348	478,719	487,637	496,789
44	Revenue ($000s)	49,106	47,698	48,064	46,422	47,112	47,918
45	Cents per KWh	9.9	9.9	9.9	9.7	9.7	9.6
46	Rider J	26,194	25,432	35,154	40,954	41,681	42,474
47	GRA Increase Req'd	15,650			19,603	33,201	44,045
48	Total Sales of Power	90,950	73,130	83,218	106,979	121,993	134,437
49	Other Revenues	394	192	510	413	413	413
50	Total Revenues	91,344	73,322	83,728	107,392	122,406	134,850

Yukon Energy Corporation
Summary of Operating and Maintenance Expenses
($000s)

Schedule 10
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	**Utility operations**							
2	Production		15,531	13,590	16,600	17,437	18,190	18,775
3	Transmission and distribution		3,267	2,976	3,740	3,415	3,831	3,438
4	General		1,615	1,923	1,980	1,760	1,801	1,830
5	Administration and general		13,092	13,060	13,951	15,705	16,674	17,446
6	Insurance		2,417	2,218	2,504	2,993	3,329	3,393
7	Sub-total		35,922	33,767	38,775	41,309	43,826	44,881
8	Donations		120	121	114	120	120	122
9	Sub-total		120	121	114	120	120	122
10	O&M not including fuel and							
11	purchased power		36,042	33,887	38,888	41,429	43,946	45,004
12	Fuel		15,295	14,367	14,214	16,802	18,661	20,627
13	Purchased power		2,759	368	1,707	3,435	3,469	3,504
14	Sub-total		18,054	14,736	15,922	20,237	22,130	24,131
15	Total operating and maintenance	S.6 L.3	54,096	48,623	54,810	61,667	66,076	69,135
	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*	*1,063*	*1,063*	*1,063*
17	*Property Taxes*		*777*	*756*	*759*	*771*	*790*	*806*
18	*less: Donations*		*-120*	*-121*	*-114*	*-120*	*-120*	*-122*
19	*O&M per Table 3.3 (Tab 3)*		*37,314*	*35,139*	*40,150*	*43,143*	*45,678*	*46,750*

Yukon Energy Corporation
Summary of Labour Costs
($000s)

Schedule 10A
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	**Total FTEs**	Tab 3, Table 3.4	119.8	113.7	123.5	128.9	139.8	144.4
2	**Total Labour Costs**		19,651	18,330	21,108	22,812	24,943	26,296
3	O&M Labour Costs	Sum Lines 5-9	16,132	15,186	17,058	18,005	19,530	20,597
4	Labour Costs to Capital		3,519	3,145	4,050	4,807	5,413	5,699
	Labour Costs							
5	Production		6,040	5,939	6,669	7,517	8,071	8,453
6	Transmission		666	343	637	565	639	648
7	Distribution		764	653	930	808	841	867
8	General		350	371	425	374	388	389
9	Administration		8,311	7,879	8,397	8,740	9,590	10,240
10	Total Labour		16,132	15,186	17,058	18,005	19,530	20,597

Yukon Energy Corporation
Summary of Cost of Long - Term Debt
($000s)

Schedule 11
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Prelim. Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
	Long-Term Debt Balance							
1	YDC Mayo B Flexible Term Debt		17,520	17,857	17,520	17,183	16,846	16,509
2	TD Bank Swap		6,552	6,987	6,552	6,108	5,655	5,192
3	YDC $92.5M Debt		55,620	59,304	55,620	51,937	48,253	44,569
4	YDC $5.5M Debt		5,505	5,505	5,505	5,505	5,505	5,505
5	YDC $21.0M Debt		13,430	14,269	13,430	12,591	11,751	10,912
6	YDC $12.1M Debt		12,136	12,136	12,136	12,136	12,136	12,136
7	TD Bank Swap		19,403	20,135	19,403	18,645	17,862	17,051
8	TD Bank Swap		5,659	5,877	5,659	5,435	5,206	4,970
9	YDC $2.9M Debt		2,871	2,871	2,871	2,871	2,871	2,871
10	2020 New Debt		4,175	4,333	4,175	4,014	3,849	3,681
11	YDC Debt - 2020		3,959	3,959	3,959	3,959	3,959	3,959
12	$7.7M TD Swap - 2021		6,850	7,079	6,850	6,614	6,371	6,121
13	$17.9M TD Swap - 2022		17,269	17,598	17,269	16,926	16,569	16,197
14	$6.425M TD Swap - 2023			6,425	6,274	6,117	5,953	5,783
15	$1.0M CAFN Debenture - 2023			1,000	1,000	1,000	1,000	1,000
16	2023 New Debt		28,874					
17	2024 New Debt		33,561		27,254	26,632	25,982	25,304
18	2025 New Debt					72,094	72,094	72,094
19	2026 New Debt						81,140	81,140
20	2027 New Debt							57,684
21	Minto Decommissioning Reserve		3,087	3,029	3,182	3,321	3,321	3,617
22	Current year-end balance		236,471	188,364	208,659	273,087	346,322	396,295
23	Previous year-end balance		209,760	187,685	188,364	208,659	273,087	346,322
24	Mid Year		223,115	188,025	198,511	240,873	309,705	371,309
	Interest Expenses							
25	YDC Mayo B Flexible Term Debt		975	993	975	957	938	920
26	TD Bank Swap		140	149	140	131	122	112
27	YDC $92.5M Debt		1,589	1,688	1,589	2,266	2,116	1,966
28	YDC $5.5M Debt		132	132	132	132	132	132
29	YDC $21.0M Debt		315	334	315	297	278	260
30	YDC $12.1M Debt		359	358	358	358	358	358
31	TD Bank Swap		673	697	673	648	621	594
32	TD Bank Swap		153	158	153	147	141	135
33	YDC $2.9M Debt		83	83	83	83	83	83
34	2020 New Debt		88	91	88	84	81	78
35	YDC Debt - 2020		62	62	62	62	62	62
36	$7.7M TD Swap - 2021		201	208	201	194	187	180
37	$17.9M TD Swap - 2022		711	724	711	697	683	668
38	$6.425M TD Swap - 2023			0	261	255	248	241
39	$1.0M CAFN Debenture - 2023			38	70	79	92	92
40	2023 New Debt		1,221					
41	2024 New Debt		832	0	244	1,178	1,128	1,091
42	2025 New Debt			0	0	827	3,280	3,280
43	2026 New Debt			0	0	0	931	3,692
44	2027 New Debt			0	0	0	0	662
45	Minto Decommissioning Reserve		110	153	153	139	0	297
46	Capital Lease Interest		5	17	45	35	25	14
47	**Total Cost of Interest**		7,650	5,886	6,253	8,569	11,507	14,916
48	Mid-Year Cost of Debt		3.43%	3.13%	3.15%	3.56%	3.72%	4.02%

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 2025, 2026 and 2027 test years, including the following:

- Background;
- Yukon Energy Fair ROE for 2025, 2026 and 2027; and
- Capital Structure.

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 11 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 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 British Columbia regulated utilities.[2] A generic cost of capital proceeding was completed in 2013[3]

[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; the Yukon Energy 2021 General Rate Application; and the Yukon Energy 2023/24 Generation 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.

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.

- A separate proceeding to determine cost of capital and relevant risk premiums for other BCUC regulated utilities was completed in 2014.[5]

- Between 2021 and 2024, the BCUC undertook a Generic Cost of Capital (GCOC) proceeding to review the existing benchmark ROE. Stage 1 of the GCOC proceeding set the deemed equity component and allowed return on equity of FEI and FortisBC (FBC). Stage 2 of the GCOC proceeding determined that FEI would act as the benchmark and set the deemed equity component and allowed return on equity for all other utilities that use the benchmark in British Columbia.

  This BCUC GCOC proceeding changed the relationship between ROEs for FEI and FBC. Prior to the BCUC Order G-236-23, FBC's approved ROE of 9.15% was based on the FEI benchmark ROE of 8.75% plus a risk premium of 40 basis points, with FEI's approved deemed equity of 38.5% being lower than FBC's deemed equity of 40.0%. In contrast, BCUC Order G-236-23 approved the same ROE (9.65%) for both FBC and FEI, but with FBC's approved deemed equity of 41% being lower than FEI's deemed equity of 45%. The effect of this is that FEI's effective equity return (ROE times deemed equity) for revenue requirement purposes now exceeds FBC's effective equity return, i.e., FEI is now assessed to have a higher business risk than FBC.

  By Order G-6-24 dated January 11, 2024, the BCUC finalized the scope for Stage 2 of the GCOC proceeding and set FEI as the Benchmark Utility. By Order G-321-24 dated November 29, 2024, the BCUC approved ROE and risk premiums for other utilities, the ROE for all utilities in that BCUC Order, including PNG-West, was approved at 10.40% which is 75 basis points over the benchmark ROE of 8.65%.

In Order 2018-10 concerning Yukon Energy's 2017-18 GRA, the Board awarded a 45-basis point risk premium adder to Yukon Energy over the BCUC benchmark ROE to compensate for its small size and risk related to generation, isolated grid and customer diversity. The Board Order recognized FBC and AEY as

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[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.

appropriate comparators for determining Yukon Energy's risk premium [i.e., Yukon Energy has more risk than FortisBC (Electric) and AEY] but did not accept PNG-West as an appropriate comparator utility.

In Order 2023-01 concerning Yukon Energy's 2021 GRA, the Board indicated its view that Yukon Energy may be less comparable to FBC due to issuance of OIC 2021/16,[6] but noted that YEC faces some incremental risk with thermal production costs for incremental loads relative to FBC. 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 effect, the Board confirmed that the Yukon Energy risk premium was at least the same as FBC.

In Appendix A to the Board Order 2024-05, the Board stated that it "continues to find that the ROE for YEC for this proceeding shall continue to be not greater than the ROE determined for FBC before the application of OIC 1995/90. Therefore, YEC's ROE for the 2023 and 2024 test years will be 9.15 percent."[7] The Board further stated that "before the application of OIC 1995/90, YEC's ROE will be 9.65 per cent versus AEY's approved ROE of 9.50 per cent for the 2023-2024 test period. This confirms that YEC relative to AEY is compensated for higher risks."

8.2 YUKON ENERGY FAIR ROE FOR 2025, 2026 AND 2027

In respect of the 2025, 2026 and 2027 test years, Yukon Energy is proposing an approach for determining fair ROE that is consistent with underlying principles provided in the most recent Board Orders. This approach offers a simple, transparent and cost-effective method to determine a consistent and fair return for Yukon utilities.

- **Step 1 – Determine Benchmark Utility ROE:** For the 2025, 2026 and 2027 test years, Yukon Energy proposes to continue to adopt the BCUC benchmark ROE of 9.65%, as most recently approved in Board Order 2024-05 for YEC.

- **Step 2 – Risk Premium adder:** The Board in Order 2024-05 stated that the ROE for Yukon Energy shall continue to be not greater than the ROE determined for FBC before the application of OIC 1995/90. The ROE for FBC was approved at 9.65% which is the same as the BCUC

[6] Due to lack of evidence on existence of asymmetric risk profile the Board made no findings on whether Yukon Energy faces more risk than FortisBC (Electric). Board Order 2023-01, Appendix A, paragraph 41.
[7] Based on the ROE of 9.65% approved for FBC less 50-basis points as per OIC 1995/90=9.15%.

benchmark ROE approved for FEI. Therefore, there is no risk premium adder proposed over the FBC ROE at 9.65% for this proceeding.

- **Step 3 – Determine Yukon Energy Allowed ROE by Deducting 50 Basis Points from the 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 9.15% which is 50 basis points below FBC ROE.

Accordingly, the proposed ROE in this Application for each test year is 9.15%, which is the same as approved for Yukon Energy's 2023/24 GRA.

Tables 8.1 and 8.2 update comparisons in prior GRAs of Yukon Energy with FortisBC (Electric) and AEY regarding size of operations, financial structure and nature of business. Compared to FortisBC (Electric), Yukon Energy continues to be much smaller in size, with a similar capital structure, much greater reliance on its own generation, lack of interconnection with external electricity markets, and higher exposure to industrial customer risks. Compared to AEY, Yukon Energy continues to have a smaller number of customers (with exposure to industrial customer risks), greater rate base costs, and much greater reliance on its own generation.

8.3 CAPITAL STRUCTURE

In Appendix A to Order 2024-05, the Board approved Yukon Energy's capital structure of 60 per cent debt and 40 per cent equity as to be reasonable and consistent with past practice. This capital structure has been approved for Yukon Energy at least since 1992. There is no new evidence that warrants the change in the capital structure. Therefore, YEC is not proposing a change to capital structure for this proceeding.

Table 8.1:
Comparison of YEC to Fortis BC & AEY – Size of Operations & Financial Structure (2023)

	YEC	Fortis BC Inc. (Electric)	AEY
Revenues ($millions)	73.1	513.0	61.7
Rate base ($millions)	326.9	1,676.0	127.2
Number of employees	114	518	67
Number of customers	2,450	150,761	20,872
Capital Structure			
Debt/Equity ratio	60%/40%	59%/41%	60%/40%
ROE Benchmark	9.65%	9.65%	9.65%
ROE Risk Adjustment	0.00%	N/A	-0.15%
Fair ROE Approved	9.65%	9.65%	9.50%
YEC Final ROE after OIC 1995/90	9.15%		

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 2024-05 in relation to YEC's 2023 and 2024 GRA. Approved ROE reflects adjustment for 50 basis points pursuant to OIC 1995/90. Employee number is FTEs without adjustment for vacancy.

2. The information for Fortis BC is based on 2023 Financial Statements available at https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/fortisbc-(electric)-fs-with-notes-q4-2023-c2-audit-sedar.pdf?sfvrsn=a13ac586_1 [accessed on March 24, 2025]. The revenue information on page 7; rate base on page 16.
Number of customers data (accessed from Appendix A2, page 6) is based on information available from Annual Review for 2024 Rates https://docs.bcuc.com/documents/proceedings/2023/doc_72776_b2fbc2024annualreviewratesapplication.pdf [accessed on March 24, 2025].
The info on capital structure and ROE is based on Information available from the BCUC GCOC proceeding Order G-236-23, page 136 https://docs.bcuc.com/documents/other/2023/doc_73454_g-236-23-gcoc-stage1-decision.pdf.
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, response to information request #9 from BCUC.

3. The capital structure and ROE for Fortis BC reflect allowed structure and allowed ROE based on the BCUC GCOC proceeding, Order G-236-23.

4. The information for AEY is based on AEY's 2023 Key Performance Indicators report filed with the YUB. Approved ROE is based on AEY's 2023-24 GRA and YUB Order 2024-01. Number of employees based on number of employees per customer and total number of customers.

Table 8.2:
Comparison of YEC to Fortis BC & AEY – Nature of Business (2023)

	YEC	Fortis BC Inc. (Electricity)	ATCO Electric Yukon
Services	Electricity	Electricity	Electricity
Acquisition of Product			
Hydroelectric	91%	42%	2%
Thermal/Other	9%	-	6%
Purchased		58%	92%
Revenue share by customer type			
Residential	5.3%	44.4%	47.5%
Commercial	13.8%	24.5%	50.1%
Industrial	19.9%	10.3%	0.0%
Wholesale	60.7%	11.6%	0.1%
Other/misc	0.4%	9.3%	2.4%
Energy sales share			
Residential	3.6%	37.6%	51.7%
Commercial	8.2%	27.8%	46.6%
Industrial	15.5%	16.2%	0.0%
Wholesale	72.2%	17.0%	0.1%
Other/misc	0.5%	1.4%	1.6%

Notes:
1. The information for Yukon Energy is from Tab 2 tables.
2. The information for Fortis BC is based on 2023 Financial Statements available at https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/fortisbc-(electric)-fs-with-notes-q4-2023-c2-audit-sedar.pdf?sfvrsn=a13ac586_1, Note 16, page 31 [accessed on March 24, 2025]; Annual Review for 2024 Rates, https://docs.bcuc.com/documents/proceedings/2023/doc_72776_b2fbc2024annualreviewratesapplication.pdf pages 18 and 41.

3. The information for AEY is based on AEY's 2023 Key Performance Indicators report filed with the YUB.

TAB 9
NET SALVAGE STUDY

REVIEW OF YUKON ENERGY CORPORATION
FUTURE REMOVAL AND SITE RESTORATION PROVISION
(NET SALVAGE)

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March 30, 2025

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1.0 INTRODUCTION

Yukon Energy Corporation ("Yukon Energy") is a regulated public utility that maintains material capital assets in service. Similar to many utility peers, prior to 2005 Yukon Energy maintained a provision for Future Removal and Site Restoration ("FRSR") also commonly known as a Net Salvage provision ("Net Salvage") which encompassed both annual accruals and annual spending. The term Net Salvage is typically meant to encompass spending on asset removal, dismantling, disposal, and site restoration, net of any salvage receipts from sale of the spare parts or scrap – multiple terms are used in various contexts to describe this concept, but they are typically synonymous.

In a rate application before the Yukon Utilities Board ("YUB") in 2005, the regulator directed a change to the practice to be applied to managing the obligations and liabilities associated with asset end-of-life and Net Salvage costs and recoveries.

Prior to 2005, Yukon Energy used an approach to accruing for future costs and recoveries associated with asset end-of-life commonly known as the Traditional Approach to Net Salvage, where costs associated with future removal and dismantling costs net of salvage are accrued during an asset's life in a manner that parallels the straight-line depreciation. In YUB Decision 2005-12, the regulator indicated that the balance at year-end 2004 was $5.757 million and annual accruals were approximately $0.5 million. The YUB directed that Yukon Energy discontinue annual accruals to the FRSR, and that YEC should use the established balance for removal ("dismantling") costs in 2005 and subsequent years, until the balance in the liability reaches $2 million, at which time Yukon Energy is to inform the YUB.

Now that the balance has reached this level, Yukon Energy is in a position to propose a new approach to managing the future cost of net salvage. This report reviews the two main approaches that Yukon Energy may elect to apply to managing Net Salvage, consistent with common regulatory practice in Canada.

1.1 SUMMARY OF CONCLUSIONS

With the termination of the drawdown phase established by YUB Decision 2005-12, two main alternatives arise as potential candidates for Yukon Energy to pursue for accruing and collecting Net Salvage or FRSR in future years.

The first candidate is what is known as the Traditional Approach, effectively the same approach used by Yukon Energy prior to 2005. This option would be challenging for Yukon Energy to implement, for two reasons. First is that Yukon Energy is somewhat limited in the data required to properly implement the approach. More important, after a period of draw-down, re-adopting the Traditional Approach will have material rate impacts which are exacerbated by the last 20 years of no collection. Were the Traditional

Approach to have been the preferred route for Yukon Energy and its regulator, the pause initiated in 2005 is counter to achieving long-term rate stability.

The second candidate is the approach used by a number of southern Canadian jurisdictions, based fundamentally around capitalizing the costs of net salvage and removal as part of any new replacement capital project, and only accruing in rates sufficient funding to address removal costs when no direct replacement project will be undertaken. This Capitalization Approach can be implemented today on a reasonable basis using available data, and without severe rate impacts. The approach also overlaps well with IFRS, and is a good match for Yukon Energy's long-lived and relatively permanent assets (e.g., hydro units and transmission lines that are likely to be maintained into the indefinite future or replaced in situ, even in a period of decarbonization initiatives).

On this basis, it is recommended that the Capitalization Approach be adopted.

The approach should be implemented by way of an annual appropriate to the FRSR regulatory asset account, based on 0.042% of gross plant. If a major upcoming terminal retirement is identified or an ARO has been recorded for a material asset, this amount should be increased to reflect this obligation as early as reasonable plans can be developed for the retirement, including timing and cost.

The account balances would only be drawn down for removal activities where there is no direct replacement asset.

Yukon Energy should also review and, if necessary, adapt its capitalization policies to ensure annual transactions accord with this approach.

2.0 YUKON ENERGY NET SALVAGE HISTORY

Prior to 2005, Yukon Energy used an approach to accruing for future costs and recoveries associated with asset end-of-life commonly known as the Traditional Approach to Net Salvage, where costs associated with future removal and dismantling costs net of salvage are accrued during an asset's life in a manner that parallels the straight-line depreciation.

Since 2005, Yukon Energy has continued to maintain the net salvage account (the FRSR) consistent with the direction in Board Order 2005-12 which terminated annual accruals. As there have been no annual accruals to the account, the balance has declined with time (as was expected). The progression of the account balance is shown in Table 1:

Table 1: FRSR Balances

Balances in FRSR by year
($000s)

	opening	spend/ recover	accrual (additions)	closing
2005	5,757	139		5,618
2006	5,618	535	-	5,083
2007	5,083	(158)	-	5,241
2008	5,241	73	-	5,168
2009	5,168	160	-	5,008
2010	5,008	243	-	4,764
2011	4,764	53	-	4,711
2012	4,711	-	-	4,711
2013	4,711	40	-	4,671
2014	4,671	-	-	4,671
2015	4,671	304	-	4,367
2016	4,367	8	-	4,359
2017	4,359	55	-	4,303
2018	4,303	340	-	3,963
2019	3,963	1,173	-	2,790
2020	2,790	53	-	2,738
2021	2,738	-	-	2,738
2022	2,738	49	-	2,689
2023	2,689	653	-	2,036
total		3,721		

As noted in Table 1, the balances reflect the ongoing spending and draw down of the account. It should also be noted that the account is not cash – it represents a balance sheet entry as a regulatory liability.

The spending on net salvage since 2005 is notably limited, averaging only $196,000 per year. A review of projects comprising the spending since 2009 ($3.1 million in total spend) indicates over half (more than $1.7 million) is related to only three projects – the removal of Whitehorse Wind #1, Whitehorse Wind #2, and the decommissioning of Whitehorse diesel units from service (WD1, WD2, and WD3).

Even over the most recent 5 years, which are somewhat higher than previous years, Yukon Energy's average annual spending is $0.376 million per year. This is a low level of spend on net salvage activities. For example, consider the following examples in Table 2 measured in relation to each utility's rate base:

Table 2: Average Annual Spending on Net Salvage Activities

$M	period	Average annual net salvage spending	Rate Base	spend as a percentage of rate base
Yukon Energy	2019-2023	0.38	376	0.10%
ATCO Electric Yukon	2016-2024	0.61	140	0.44%
BC Hydro	2023-2030	59.00	23,237	0.25%
AltaLink Management	2019-2023	31.08	7,736	0.40%
Northwest Territories Power	2021-2024	2.17	364	0.60%

notes:

AEY per 2023 GRA

BC Hydro per F2023-F2025 GRA

AltaLink per AUC proceeding 26509

Yukon Energy rate base per 2023 GRA

NTPC per 2024-26 GRA

From the above data, it appears likely that Yukon Energy has approached use of the FRSR with restraint, likely accounting for costs as either capital or O&M, which could have been included in the FRSR based on utility industry practice.

3.0 NET SALVAGE APPROACHES

3.1 Background

There are a number of different approaches to addressing the costs of Net Salvage for utilities in Canada. Common among these approaches is the recognition that the costs of Net Salvage comprising removal, dismantling, site restoration etc. are appropriate utility costs for recovery from customers. The costs of removing an asset are a key part of the costs of the service provided by the asset. As such these costs are appropriately included in the utility Revenue Requirement for the purpose of setting rates.

Variations occur in establishing an approach to managing Net Salvage costs, comprised of the complementary consideration of *in which time period* the collection will occur and *at what varying level* which can be combined into a number of approaches. Each of the common approaches has different degrees of rate impact, cash flow implications, and data requirements.

There are also variations around whether the same approach will be applied to all removals, or only to a subset of removals, typically reflecting two types of removals:

- The concept of a **terminal retirement** is that the asset is being removed from service and no replacement or equivalent asset will be built in the same location to replace it.
- In contrast, an **interim retirement** relates to cases where the asset in question is being removed and replaced by a similar asset in the same vicinity. In utility operations, this is typically the far more common type of retirement.

The main projects cited for Yukon Energy's historical net salvage spending (wind turbine removal and Whitehorse diesel decommissioning) likely fit into the definition as a terminal retirement.

The three main variants for periods of collection are:

1) Collected concurrent with the asset's service life, which includes methods known as the **Traditional Method**, and the far less common **Constant Dollar Net Salvage (CDNS)** approach
2) Collected on a largely **Pay-As-You-Go** basis as the assets are retired (or in a short number of years close to the year of retirement).
3) Collected via **Capitalization** as part of the capital cost of any replacement asset installed at the time of the retirement of the first asset. This third approach is only an option for interim retirements.

In practice, utilities in Canada primarily make use of two approaches – first is the Traditional Approach, and second is a hybrid approach consisting of Capitalization for interim retirements, combined with an alternative approach (either Pay-As-You-Go or Traditional Approach) for terminal retirements.

3.2 The Traditional Approach

The Traditional Approach is the most common, and has been widely used for many years. This is the approach that Yukon Energy used before the YUB adopted the pause in 2005. Other examples include:

- ATCO Electric Alberta
- Northwest Territories Power Corporation
- AltaGas Utilities
- ATCO Gas
- FortisBC Inc.
- Naka Power NWT (previously Northland Utilities Limited (NWT)).

Of particular note to Yukon Energy are ATCO Electric Yukon and BC Hydro given proximity and common history.

ATCO Electric Yukon (AEY) (previously Yukon Electrical Company Limited, or YECL) used the traditional approach to net salvage in periods prior to 2009. In YUB decision 2009-2, the YUB directed that AEY should cease accruals related to Net Salvage, similar to the YEC approach directed in 2005, but continue to use the Net Salvage balance to pay for removal activity. This reduced AEY's revenue requirement for the accrual by approximately $1 million per year for 2009[1]. At the time AEY had a Net Salvage balance of $4.7 million. AEY continued to use this approach until its 2023-2024 GRA, when the balance had declined to below $0.5 million.[2] AEY proposed to reimplement the traditional approach, with an annual accrual of $2.1 million per year (2024), which was approved by the YUB.[3] The YUB, however, significantly reduced the net salvage estimates, leading to a net impact of $0.940 million on 2024 revenue requirement[4]. The addition of $0.940 million per year to revenue requirement was a material impact in that proceeding, given that AEY's own source revenue requirement (i.e., excluding fuel and purchased power) totals only $30.995 million in 2024[5].

BC Hydro received an order from its regulator, the British Columbia Utilities Commission (BCUC) to suspend accruals to its Net Salvage accrual account in 2005 (similar to the 2005 Yukon Energy direction). Prior to 2005, BC Hydro used the Traditional Method for Net Salvage accruals.[6] The balance in 2005 was $233 million, which was to be used to fund removal activities but with no new accruals.[7] The previous accrual of $17 million per year was terminated.[8]

[1] YUB Order 2009-2 Appendix A, page 21.
[2] YECL 2023-2024 GRA, section 7.2.
[3] YUB Order 2024-01 Appendix A, section 5.3.5
[4] AEY 2023-2024 GRA Compliance Filing, Attachment 1, Schedule 7.1
[5] AEY 2023-2040 GRA Compliance Filing, Attachment 1, Schedule 1.1.
[6] Based on the description in BCUC Order G-96-04.
[7] BCUC Order G-96-04.
[8] BCUC Order G-47-18 page 158.

By F2017, the Net Salvage balance was approaching zero[9]. As part of its F2017-F2019 RRA, BC Hydro proposed to implement the Pay-As-You-Go approach, by including the forecast annual dismantling costs into revenue requirement[10]. BC Hydro proposed a new regulatory deferral for dismantling costs, that would true-up actuals to forecasts to eliminate risk from BC Hydro for variances. The BCUC approved the new account for F2017-F2019 only, noting that the Pay-As-You-Go approach could lead to variances but that with experience, "BC Hydro should be able to provide its best estimate on site dismantling and restoration necessary for the facilities that it operates and manages. Any variance remaining from factors outside of management's control may not be significant enough to warrant the variance treatment for the forecast dismantling cost."[11] In short, as of F2017, the main components of the net salvage component of BC Hydro's costs were fully incorporated into a Pay-As-You-Go approach.

For F2020 to F2021, BC Hydro applied to extend the dismantling account due to the nature of the costs being non-controllable[12], but continued to apply the Pay-As-You-Go approach. No intervenor opposed this approach. The BCUC approved the extension of the account, but expressed concern with the level of dismantling costs (including a table showing over the previous 8 years, spending totaled $267.3 million, or an average of $33.4 million/year). The Commission noted:

> However, the Panel also notes that dismantling costs have been increasing and is concerned with whether BC Hydro's approach to dismantling costs would result in intergenerational equity issues. In the Panel's view, the dismantling of property, plant and equipment, similar to negative salvage, should be paid for by the customers who benefited from the use of these assets. Therefore, the Panel directs BC Hydro to provide in its next RRA, an assessment of whether its current practice of expensing dismantling costs as they occur would result in intergenerational inequity and to provide options on how it could calculate and collect dismantling costs to better promote intergenerational equity. For these reasons, the Panel approves the use of the Dismantling Cost Regulatory Account, as requested by BC Hydro, for the Test Period only.

For F2022, BC Hydro sought approval to continue the dismantling deferral account, and indicated it was preparing a proposal for depreciation and net salvage[13].

In its F2023-F2025 Revenue Requirement Application, BC Hydro sought to re-implement the Traditional Approach. BC Hydro estimated that a full implementation of the Traditional Approach, but without phase-

[9] BCUC Order G-47-18, page 61.
[10] BCUC Order G-47-18, page 61.
[11] BCUC Order G-47-18, page 62.
[12] BCUC Order G-246-20, page 122.
[13] Order G-187-21, page 69.

in, would result in annual accruals of $112 million in F2026.[14] BC Hydro proposed to adopt the principle that the Traditional Approach should be used, but did not seek approval to begin accruals in the F2023-F2025 period. The BCUC approved the use of the Traditional Approach in principle, for implementation in F2026 subject to BC Hydro providing additional analysis on net salvage levels and phase-in impacts. This implementation and update of estimates has not yet occurred.

3.2.1 Implementation and Cost Impacts if Adopted

For Yukon Energy, re-adopting the traditional approach would reflect a common utility precedent in Canada, and matches the method adopted by peers who had a similar history with pausing then reinitiating their Net Salvage provision – specifically, AEY and BC Hydro.

However, there are two key issues with adopting the traditional approach at this time. The first is data limitations, and the second is revenue impacts.

On the first issue, Yukon Energy's experience with respect to data collection on net salvage (particularly for interim retirements) is likely a barrier to accurately implementing the Traditional Approach at this time. As noted earlier in this discussion, the Yukon Energy record appears to be heavily weighted towards terminal retirements with much less reflection of the costs of net salvage associated with interim retirements. It would normally be expected that the interim retirements experienced add up to many multiples of the costs recorded for terminal retirements, yet Yukon Energy's record with respect to interim retirements does not match this pattern (more than half of recorded net salvage costs are for terminal retirements). For example, AltaLink has filed estimates of terminal versus interim retirements that indicate interim retirements typically are 10 times the experience with terminal retirements[15].

This low level of recorded spending for interim retirements is not consistent with the principles and development of estimates normally adopted for the Traditional Approach to Net Salvage. If the Traditional Approach is re-implemented, it will be important to ensure that capital asset policies for recording project costs appropriately track the removal portion of all capital jobs to permit appropriate allocation of spending to capital asset additions versus removal/net salvage costs.

A review of potential removal costs under a Traditional Approach requires three data components:

1) An estimate of the costs of removal as a percentage of the original cost to install an asset. These percentages are typically derived from a mixture of a utility's own data and a review of peers. Given Yukon Energy's limited own-source data, ratios have been developed focused on peers and

[14] BC Hydro F2023-F2025 Revenue Requirement Application, Table 8-6.
[15] AUC Exhibit 26509-X0023, AML-AUC-2021AUG20-011. Pdf page 26 of 315.

previous Yukon benchmarks. The comparison is provided in Attachment A1. Based on this review, estimated ratios as follows appear to be appropriate:

a. Hydro assets – 10%

b. Diesel and LNG assets – 10%

c. Distribution – 20%

d. Transmission and subtransmission – 30%

e. General Plan, excluding Transportation – 5%

2) An estimate of the expected average remaining life of assets in service. Data for this is available from Yukon Energy's last depreciation study.

3) A period for the "true-up" of any deficits or surpluses compared to the balance estimated to be required as of a given date. This is a significant portion of the cost impact of the Traditional Approach, as the present balance below $2 million is far short of what would be in place had the Traditional Approach been retained in service throughout the intervening years. Even if only the previous $0.5 million/year accrual had been continued (ignoring growth in the asset base), there would be approximately $10 million additional in the FRSR today. For the purposes of this analysis, an approach based on recovering this true-up amount over the expected average remaining life has been assumed. This is the longest period that would normally be considered for a true-up (i.e., lowest rate impact).

Based on the above approach, there would be 2 components to the implementation of Net Salvage at this time:

- The ongoing normal annual accrual would total $2.473 million/year. This is the estimated amount needed to keep up with the present plant in service. As spending is far below this level, the balance in the Net Salvage provision would grow quickly, reflecting building up to a balance that would be discharged with far-future expected major removal activities. While this is approximately 5 times the amounts that were being accrued in 2005 (at about $0.5 million), this ratio is reasonably consistent with BC Hydro who saw their annual accrual grow from $17 million to $112 million, a ratio of 6.6 times. AEY also saw material growth of a factor of 2.2, but this was over a somewhat shorter period (15 years, as opposed to 20)
- The added need for a true-up provision is material, and is based on the relative procession of assets through their lives since the 2005 balance was set in decline. At this time, a fully-funded Net Salvage reserve balance is $40.170 million (as compared to slightly over $5 million in 2005,

and less than $2 million today). Based on the amortization of the true-up over the expected average remaining life, this balance would lead to an additional annual expense of $2.284 million.

Combined, the annual expense to implement the Traditional Approach at this time is estimated at $4.742 million/year based on plant in service in 2024.

The calculation of the above figures is provided in Attachment A1, showing the derivation of the net salvage costs, and the salvage parameters compared to peers.

3.3 Capitalization Approaches

The most common alternative to the Traditional Approach is to adopt a procedure for interim retirements that uses the Capitalization approach, combined with a provision for accruals or expensing tied to terminal retirements.

This approach is not as common as the Traditional Approach, though it has been adopted in recent years for a number of utilities. The analytical basis ties to equitable treatment - at any given time, ratepayers will be shouldering all costs to finance and depreciate the original cost of the assets in service. For any given asset, the nominal cost of return and depreciation will decrease over time (as the asset is depreciated), and the real cost (especially in the case of load growth) will decline even faster. Yet every user of the system receives effectively the same service from the asset whether it is new or old (e.g., same kW produced or transmitted). Therefore, the most equitable time to recover salvage is in the latter years of the asset's life, when the same service is otherwise being delivered at a lower cost.

Outside of this mathematical relationship, there is also a solid basis in equitable treatment to conclude, for those assets that will be replaced in situ, that some of the benefit of the existing asset in fact accrues to the future customers served by second generation of the asset.

Taking into account the above factors, a number of regulators ultimately concluded to adjust the method of net salvage to include the costs of removal of any interim retirement into the capital costs of the replacement asset[16].

This same broad type of methodology has been adopted in a number of cases in Canada, including the following:

- Altalink Utilities Inc.
- Manitoba Hydro

[16] AUC Proceeding 25870

- Newfoundland Hydro
- EPCOR Utilities[17]

Other utilities, such as AltaGas[18] and ATCO Gas[19], have been directed to study the approach.

It is helpful to note the specific implementation details that differ to some degree among the main utility examples:

- Altalink is presently in a transition period, where charges for all removal costs (interim or terminal) are charged to the residual balance remaining from the period when Altalink used the traditional method (much like the Yukon Energy remaining Net Salvage balance). After this period is over, removal costs linked to replacement projects (i.e., interim retirements) will be charged to the capital cost of the replacement asset. Final terminal retirements will be expensed, which has not yet been operationalized, but is expected in practice to be included in revenue requirement through a deferral account treatment (effectively a Pay-As-You-Go funding model, with deferral and stabilization to fund ongoing occasional larger terminal removal activities).
- Manitoba Hydro includes removal costs for interim retirements as part of the capital cost of the replacement asset. As noted in Manitoba Hydro's 2020/21 Annual Report: "When the costs of removing an asset from service are incurred to facilitate the installation of a new asset, the costs to remove the asset from service are added to the costs of the new asset. When an asset is retired from service and not replaced with a similar asset, the costs of removing the asset from service are treated similarly to the net gain or loss on retirement of assets."[20] In effect, given the form of regulation for Manitoba Hydro, the gain or loss on retirement is expensed.
- Newfoundland Hydro uses the same approach as Manitoba Hydro for interim retirements. For final retirements, the Annual Report or NALCOR (the owner of Newfoundland Hydro's Regulated operations): "A significant number of Nalcor's assets include generation plants, transmission assets and distribution systems. These assets can continue to run indefinitely with ongoing maintenance activities. As it is expected that these assets will be used for an indefinite period, no removal date can be determined and consequently, a reasonable estimate of the fair value of the cost of decommissioning liability cannot be determined at this time. If it becomes possible to estimate the

[17] Decision 22570-D01-2018 at para 91.
[18] AUC Decision 24161-D03-2019
[19] AUC Decision 24188-D02-2020.
[20] Manitoba Hydro 2020/21 Financial Statements, note 3(g).

> fair value of the cost of removing assets that Nalcor is required to remove, a decommissioning liability for those assets will be recognized at that time."[21]

In short, none of Altalink, Newfoundland Hydro, nor Manitoba Hydro ever accrues or expenses the costs of interim retirements, but instead considers these costs to be part of the cost of the replacement asset.

However, for terminal retirements, Newfoundland Hydro will accrue a balance, but not until later in an asset's life when a reasonable estimate can be made of the fair value of the cost of removal. For Manitoba Hydro, these amounts are understood to be charged to accumulated depreciation and expensed (which in practice results in a regulatory treatment that later seeks recovery from ratepayers, as Manitoba Hydro does not operate with a strict annual revenue requirement model). For Altalink, the amounts are to be collected in a stabilized Pay-As-You-Go model.

3.3.1 Implementation and Cost Impacts if Adopted

An analysis of the Yukon Energy Net Salvage spending suggests that the majority of spending that has been tracked to the Net Salvage account represents terminal retirement activities.

On this basis, it can be assumed that a reasonable estimate for routine terminal retirements alone (not including interim retirements) can be developed from the long-term historical record, in relation to the asset base in place at the time. This data is shown in Table 3[22]:

[21] Note that the excerpt is from NALCOR's 2020 Financial Statements MD&A page 44. This is in contrast to Concentric response to AMPC IR 1.38.5, which suggests NALCOR uses the "traditional" approach for terminal retirements. The above described approach to terminal retirements does not fit with the traditional approach as it only accrues balances late in an asset's life.

[22] Gross PPE from Yukon Energy Annual Reports up to 2014, and from Yukon Energy Regulatory Schedules from 2015 onwards, as filed with the YUB.

Table 3: Spending in Relation to Gross PPE

FRSR Spending in Relation to Gross PPE
($000s)

	spend/ recover	Gross PPE (including WIP)	Ratio
2005	139	222,116	0.063%
2006	535	226,567	0.236%
2007	(158)	237,646	-0.066%
2008	73	275,268	0.027%
2009	160	297,262	0.054%
2010	243	378,170	0.064%
2011	53	473,168	0.011%
2012	-	495,796	0.000%
2013	40	520,406	0.008%
2014	-	555,552	0.000%
2015	304	577,888	0.053%
2016	8	589,387	0.001%
2017	55	598,756	0.009%
2018	340	615,387	0.055%
2019	1,173	642,291	0.183%
2020	53	667,962	0.008%
2021	-	691,598	0.000%
2022	49	734,073	0.007%
2023	653	796,724	0.082%
		mean	0.042%

Based on an estimated 2024 year-end Gross PPE of $841.173 million, this would yield an estimated net salvage spending on terminal retirement activities of $0.352 million.

The final consideration is the overlap with the IFRS Asset Retirement Obligation ("ARO"). It is understood that Yukon Energy has had little need to record AROs in recent years, so there has been no need to resolve any potential conflict between the activities meant to be reflected in the FRSR and AROs. Going forward, there is the potential of more significant AROs. To maintain a complementary operation of FRSR and AROs, it will be necessary to be clear on regulatory versus IFRS accounting. The FRSR is inherently a financial liability – it represents dollars collected for a purpose that have not yet been spent and are not income to the utility. The ARO is different in that it is an activity-based liability – a future activity that the utility is obligated to undertake. For regulatory purposes, the only account necessary to record is the FRSR, though the balance being targeted could be informed by an IFRS ARO. For example, if a large ARO is being recorded, this is a sign the FRSR accrual should be increased over time to match the upcoming spend, if it is insufficient. For financial reporting purposes, further consideration of IFRS and the best way to reflect the interaction will be required. It would appear appropriate that the ARO and FRSR are structured to avoid double-counting of the same principles on the balance sheet. For example, the value of the FRSR reported on the balance may be best represented by being reported net of any ARO already recorded. However, further accounting advice may be required to consider alternatives, and whether additional direction is required from the regulator in respect of the FRSR regulatory asset.

Implementation of the Capitalization approach would therefore include three separate aspects:

1) **Terminal Retirements:** A revision to Yukon Energy's capital asset policy that makes clear that any and all removal costs associated with removal of assets which are being effectively replaced in the same location are part of the capital cost of new assets in that location. If any change is necessary in practice, it should not be a major change, as it appears this is largely consistent with Yukon Energy practice (based on the low rate of charges to the FRSR provision). Also, this approach is routinely cited as being consistent with IFRS (for example, see Altalink AUC proceeding 23848).
2) **Routine Interim Retirements:** Maintain the FRSR account as part of regulated ratemaking. Implementation of a new accrual in rates of 0.042% of gross PPE each year (approximately $0.352 million/year) to sustain the account solely related to the estimated requirement for funding the costs of routine terminal retirements.
3) **Non-Routine Retirements:** Adoption of a practice that, if needed, any major non-routine terminal retirements are addressed at an early opportunity through accruals in rates. For example, if a major transmission or hydro asset is facing terminal retirement, costs for that activity should be estimated at an early opportunity and an accrual built into rates to build up the balances needed to undertake the removal activity. Note that this would be expected to be very rare (no such event is reflected in the 2005-2023 record).
4) **Addressing the overlap with ARO in financial reporting.**

With the above three provisions, it would be expected that the current FRSR balance of somewhat less than $2 million would be sustained, and permit the annual provision to be maintained at the 0.042% level for a period of time, with the ability to absorb events of higher than average terminal retirement cost.

4.0 CONCLUSION

Based on the above considerations, Yukon Energy is advised to pursue a Capitalization approach to managing net salvage costs. The annual accrual should be set at 0.042% of Gross PPE, or approximately $0.352 million per year, updated at each rate application. If a major upcoming terminal retirement is identified or an ARO has been recorded for a material asset, this amount should be increased to reflect this obligation as early as reasonable plans can be developed for the retirement, including timing and cost.

ATTACHMENTS

Attachment A1 – Calculation of Traditional Approach to Net Salvage

			2018 Depreciation Study Parameters				Peer Utility Net Salvage Rates									
Asset Class ID	Asset Class ID Descriptions	2024 Forecast Gross Plant in Service	Approved Life	Amortization Rate based on Board Approved Life Parameters (Order 2022-03)	Remaining Life	2024 Depreciation	BC Hydro 2021 Study (Decision G-91-23)	Fortis BC 2017 Study (Decision G-166-20)	NTPC 2020 Study (Phase-in)	Maritime Electric 2020 Depr Study	Estimated Average Net Salvage Rate for YEC	Annual Net Salvage Keep-up Provision (2024 Forecast)	Accum. Amor. Ratio to Gross Plant	Catch-up Amount	Annual Provision for Catch-up (2024 Forecast)	Total Net Salvage Provision (2024 Forecast)
	Hydro Plant															
1615-200	Hydro-Strctrs & Imprvmts	55,493,770	72	1.39%	56.6	770,747		10%	8%				-30%	1,674,967	29,593	
1615-201	Hydro-Building & Imprvmts	10,441,993	40	2.50%	38.59	261,050		10%	8%				-30%	315,170	8,167	
1615-205 & 1615-206	Hydro-Rsrvoirs Dams & Wtrways	175,789,457	103	0.97%	73.55	1,706,694		25%	8%				-30%	5,305,850	72,139	
1615-504 & 1615-506	Hydro-Wtrwhls, Trbines & Gen's	40,243,046	85	1.18%	45.53	473,448		25%	8%				-30%	1,214,655	26,678	
1615-600	Hydro-Accessory Electric Equip	27,836,431	40	2.50%	28.8	695,911		20%	8%				-30%	840,186	29,173	
1615-601	Hydro Accessory Digital Equip	872,322	20	5.00%	18.5	43,616		20%	8%				-30%	26,329	1,423	
1615-700	Hydro-Misc Power Plant Equip	12,191,310	30	3.33%	21.58	406,377		15%	5%				-30%	367,970	17,051	
1615-730	Hydro- Fences	108,787	30	3.33%	21.7	3,626		15%	8%				-30%	3,284	151	
	Hydro Plant Total	322,977,116				4,361,468	10%				10%	436,147	-30%	9,748,412	184,377	620,524
	Diesel Plant															
1620-200	Diesel-Strctrs and Imprvmts	7,248,598	72	1.39%	42.77	100,675			13%	3%			-51%	372,369	8,706	
1620-201	Diesel-Building & Imprvmnt	502,429	55	1.82%	47.65	9,135			13%	3%			-51%	25,810	542	
1620-403	Diesel-Fuel Hldrs,Prdcts&Accss	2,895,496	40	2.50%	26.04	72,387			25%	3%			-51%	148,745	5,712	
1620-500	Diesel-Gnrtng Equip & Prime	12,891,063	40	2.50%	19.47	322,277			8%	3%			-51%	662,229	34,013	
1620-501	Diesel Assets Overhaul	3,136,061	11	9.09%	0	285,096			8%	3%			-51%	161,103	161,103	
1620-508	Diesel-Minto Gnrtng Equip	257,792	12	8.33%	2.5	21,483			8%	3%			-51%	13,243	5,297	
1620-600	Diesel-Acc Electric Equip	9,527,355	45	2.22%	29.63	211,719			8%	3%			-51%	489,432	16,518	
1620-700	Diesel-Misc Power Plant Equip	1,984,007	30	3.33%	17.74	66,134			0%				-51%	101,921	5,745	
	Diesel Plant Total	38,442,802				1,088,906	10%				10%	108,891	-51%	1,974,853	237,637	346,527
	Distribution System															
1625-300	Dist System - Poles & Fxtrs	15,550,611	40	2.50%	31.9	388,765		35%	5%	65%			-31%	963,342	30,199	
1625-304	Dist System - Brushing	62,748	50	2.00%	20.69	1,255		30%					-31%	3,887	188	
1625-305	Dist System - Survey Costs	929,248	50	2.00%	40.61	18,585							-31%	57,566	1,418	
1625-401	Dist System - O/H Cndctrs	400,625	50	2.00%	37.18	8,012		35%	5%	65%			-31%	24,818	668	
1625-410	Dist System - O/H Services	3,672,313	40	2.50%	22.4	91,808		35%	8%	65%			-31%	227,496	10,156	
1625-501	Underground Conduit	539,907	40	2.50%	37.65	13,498		30%		15%			-31%	33,447	888	
1625-510	Dist System - Undrgrnd Cnduit	60,805	40	2.50%	33.22	1,520		30%		15%			-31%	3,767	113	
1625-610	Dist System - Meters	438,246	16	6.25%	2.36	27,390		30%		5%			-31%	27,149	11,504	
1625-620	Dist System - Meter Equip	404,266	16	6.25%	2.82	25,267		30%		5%			-31%	25,044	8,881	
1625-710	Dist System - Sbstn EEquip	3,086,841	40	2.50%	25.29	77,171		25%		15%			-31%	191,226	7,561	
1625-720	Dist System - Sbstn Buildings	90,834	55	1.82%	28.51	1,652		25%		15%			-31%	5,627	197	
1625-730	Dist System- Substation Fences	140,640	30	3.33%	26.51	4,688		25%		15%			-31%	8,712	329	
1625-815	Dist System - Street Lights	845,795	40	2.50%	27.69	21,145		15%	8%	25%			-31%	52,396	1,892	
1625-905	Dist System - Line Trxformers	5,666,718	35	2.86%	14.33	161,906		30%	5%	22%			-31%	351,047	24,497	
1625-961	Dist System - Sentinel Lights	51,085	30	3.33%	16.01	1,703		15%	8%	25%			-31%	3,165	198	
	Distribution System Total	31,940,685				844,365	20%				20%	168,873	-31%	1,978,688	98,689	267,562
	Main Transmission Facilities															
1635-300	Main Trx - Poles & Fxtrs	84,738,673	65	1.54%	39.74	1,303,672		35%	13%	90%			-27%	6,948,867	174,858	
1635-304	Main Trx - Brushing	17,035,511	60	1.67%	48.97	283,925		30%	13%				-27%	1,396,971	28,527	
1635-305	Main Trx - Survey Costs	4,368,839	60	1.67%	47.13	72,814		30%					-27%	358,260	7,602	
1635-402	Main Trx - O/H Cndctrs/Poles	20,539,508	60	1.67%	47.84	342,325		30%	13%	90%			-27%	1,684,311	35,207	
1635-404	Main Trx - O/H Cndctrs/Towers	282,607	60	1.67%	30.48	4,710		30%	13%	90%			-27%	23,175	760	
1635-710 & 1635-711	Main Trx - Sbstn Equip	103,012,358	54	1.85%	35.95	1,907,636		25%	10%	15%			-27%	8,447,373	234,976	
1635-720	Main Trx - Sbstn Buildings	9,056,011	55	1.82%	49.39	164,655		25%	10%	15%			-27%	742,625	15,036	
1635-730	Main Trx - Sbstn Fences	279,051	30	3.33%	23.09	9,302		25%	10%	15%			-27%	22,883	991	
	Main Transmission Facilities Total	239,312,559			322.59	4,089,039	30%				30%	1,226,712	-27%	19,624,465	497,957	1,724,669

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Asset Class ID	Asset Class ID Descriptions	2024 Forecast Gross Plant in Service	2018 Depreciation Study Parameters: Approved Life	Amortization Rate based on Board Approved Life Parameters (Order 2022-03)	Remaining Life	2024 Depreciation	Peer Utility Net Salvage Rates: BC Hydro 2021 Study (Decision G-91-23)	Fortis BC 2017 Study (Decision G-166-20)	NTPC 2020 Study (Phase-in)	Maritime Electric 2020 Depr Study	Estimated Average Net Salvage Rate for YEC	Annual Net Salvage Keep-up Provision (2024 Forecast)	Accum. Amor. Ratio to Gross Plant	Catch-up Amount	Annual Provision for Catch-up (2024 Forecast)	Total Net Salvage Provision (2024 Forecast)
	Sub Transmission Lines															
1640-300	Sub Trx - Poles & Fxtrs	4,645,012	65	1.54%	24.84	71,462		35%	13%	90%			-64%	885,606	35,652	
1640-301	Sub Trx - Poles & Fxtrs Mnt Mn	2,681,352	12	8.33%	2	223,446		30%	13%	90%			-64%	511,220	255,610	
1640-304	Sub Trx - Brushing	42,151	60	1.67%	58.52	703		30%					-64%	8,036	137	
1640-306	Sub Trx - Brushing Mnt Mn	438,290	12	8.33%	2	36,524		30%					-64%	83,563	41,782	
1640-307	Sub Trx - Survey Costs Mnt Mn	96,403	12	8.33%	2	8,034		30%					-64%	18,380	9,190	
1640-401	Sub Trx - O/H Cndctrs	1,862,351	60	1.67%	44	31,039		30%	13%	90%			-64%	355,071	8,070	
1640-405	Sub Trx - Undrgrnd Cndctrs/Cnd	79,862	45	2.22%	14.12	1,775		30%					-64%	15,226	1,078	
1640-407	Sub Trx - O/H Cndctrs Mnt Mn	932,947	12	8.33%	2	77,746		30%	13%	90%			-64%	177,873	88,937	
1640-710	Sub Trx - Sbstn EEquip	8,200,567	54	1.85%	41.87	151,862		25%	10%	15%			-64%	1,563,499	37,342	
1640-711	Sub Trx - Sbstn Equips Mnt Mn	7,205,898	12	8.33%	2	600,491		25%	10%	15%			-64%	1,373,858	686,929	
	Sub Transmission Lines Total	26,184,833				1,203,081	30%				30%	360,924	-64%	4,992,333	1,164,727	1,525,651
	Buildings & Other Equipment															
1645-110	Bldg&Otr - Survey Costs Land	5,040	50	2.00%	17.18	101		5%		10%			-44%	111	6	
1645-200	Bldg&Otr-Strctrs/Imprvmnt Hyd	3,050,343	50	2.00%	44.39	61,007		5%		10%			-44%	66,903	1,507	
1645-201	Bldg&Otr - Building & Imprvmnt	13,329,109	55	1.82%	32.5	242,347		5%		10%			-44%	292,349	8,995	
1645-202	Bldg&Otr-Office Frntr & Equip	2,307,989	20	5.00%	5.34	115,399		5%					-44%	50,621	9,480	
1645-210	Bldg&Otr - Comm Site Towers	22,508	40	2.50%	25.26	563		5%		10%			-44%	494	20	
1645-220	Bldg&Otr - Comm Site Fences	131,448	30	3.33%	20.65	4,382		5%		10%			-44%	2,883	140	
1645-320	Bldg&Otr - Computer Hardware	1,889,795	7	14.29%	2.99	269,971		5%		10%			-44%	41,449	13,863	
1645-330	Bldg&Otr - Computer Software	0	5	20.00%	2.55	0		5%		10%			-44%	0	0	
1645-505	Bldg&Otr - Tools & Instruments	3,748,061	20	5.00%	9.24	187,403		5%		10%			-44%	82,207	8,897	
1645-507	Bldg&Otr - Wind Mntrng Equip	0	15	6.67%	1.5	0		5%		10%			-44%	0	0	
1645-605	Bldg&Otr - Comm Equip	6,718,210	20	5.00%	9.68	335,910		5%		10%			-44%	147,351	15,222	
1645-810	Bldg&Otr - Houses/Land	68,854	40	2.50%	29.85	1,721		5%		10%			-44%	1,510	51	
1645-820	Bldg&Otr - Houses/Buildings	2,510,576	40	2.50%	24.85	62,764		5%		10%			-44%	55,065	2,216	
	Total Building	33,781,933				1,281,569	5%				5%	64,078	-44%	740,943	60,396	124,474
	Transportation															
1650-411	Trxptn - Utility Vehicles	448,260	8	12.50%	3.97	56,033										
1650-412	Trxptn - Sedans & Stn Wagons	261,643	11	9.09%	4.74	23,786										
1650-420	Trxptn - Trucks & Pole Trailer	88,711	25	4.00%	18.81	3,548										
1650-430	Trxptn -Pole Trailer>10,000lbs	66,388	25	4.00%	16.97	2,656										
1650-440	Trxptn - Trucks 3/4 to 2 Ton	4,780,822	9	11.11%	5.24	531,202										
1650-470	Trxptn - Trucks > 3Tons	2,287,704	20	5.00%	13.79	114,385										
1650-490	Trxptn - Foremost	1,240,792	20	5.00%	11.58	62,040										
	Total Transporation	9,174,321				793,650										
	LNG Plant															
1665-200	Structures and Improverments	6,248,874	72	1.39%	68.85	86,790							-23%	140,601	2,042	
1665-403	Fuel Holders	13,337,568	60	1.67%	56.85	222,293							-23%	300,097	5,279	
1665-500 & 1665-504	LNG Generator	22,359,448	40	2.50%	37.64	558,986							-23%	503,091	13,366	
1665-600	Accessory Electric Equipment	3,693,853	45	2.22%	41.88	82,086							-23%	83,112	1,985	
1665-700	Miscellanours Power Plant Equi	2,920,651	30	3.33%	26.95	97,355							-23%	65,715	2,438	
1665-730	LNG Fence	787,736	30	3.33%	26.88	26,258							-23%	17,724	659	
	Total LNG	49,348,131				1,073,767	10%				10%	107,377	-23%	1,110,341	25,769	133,146
	Total YEC	751,162,379				14,735,845						**2,473,002**		40,170,034	**2,269,551**	**4,742,552**

TAB 10
AUDITED FINANCIAL STATEMENTS

Yukon Energy Corporation
Statement of Financial Position
(in thousands of Canadian dollars)

As at	December 31 2023	December 31 2022
Assets		
Current		
Accounts receivable (Note 5)	17,059	20,404
Inventories (Note 6)	5,072	4,944
Prepaid expenses	1,686	689
	23,817	26,037
Non-current		
Property, plant and equipment (Note 7)	570,446	520,472
Intangible assets (Note 8)	27,342	21,671
Right-of-use assets (Note 9)	1,776	1,231
Derivative related asset (Note 26)	2,405	4,908
Total assets	**625,786**	574,319
Regulatory debit balances (Note 10(a))	38,272	32,513
Total assets and regulatory debit balances	**$ 664,058**	$ 606,832
Liabilities		
Current		
Bank indebtedness (Note 11)	$ 44,457	$ 11,123
Accounts payable and accrued liabilities (Note 12)	21,644	16,785
Construction financing (Note 13)	58,277	21,017
Dividend payable (Note 27)	-	11,500
Current portion of deferred revenue (Note 17)	1,851	1,380
Current portion of lease liability (Note 9)	160	130
Current portion of long-term debt (Note 14)	62,733	6,900
	189,122	68,835
Non-current		
Post-employment benefits (Note 15)	964	827
Contributions in aid of construction (Note 16)	170,169	168,893
Deferred revenue (Note 17)	17,615	17,319
Lease liability (Note 9)	695	135
Long-term debt (Note 14)	122,743	178,051
Total liabilities	**501,308**	434,060
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	74,289	94,796
Total equity	**129,257**	149,764
Total liabilities and equity	**630,565**	583,824
Regulatory credit balances (Note 10(b))	33,493	23,008
Total liabilities, equity and regulatory credit balances	**$ 664,058**	$ 606,832

Commitments and Contingencies (Notes 23 and 24)

The accompanying notes are an integral part of these financial statements.

Approved by the Board

Lesley Cabott (May 9, 2024 15:15 PDT), Chair

Gayle Corry (May 9, 2024 19:28 PDT), Director

Yukon Energy Corporation

Statement of Operations and Other Comprehensive Income
(in thousands of Canadian dollars)

For the year ended December 31	**2023**	**2022**
Revenues		
Sales of power (Note 18)	$ 78,458	$ 80,520
Other (Note 19)	6,565	3,907
	85,023	84,427
Operating expenses		
Operations and maintenance (Note 20)	36,936	35,178
Depreciation and amortization (Notes 7, 8 and 9)	14,405	14,229
Administration (Note 21)	17,575	14,856
	68,916	64,263
Income before other income and other expenses	**16,107**	20,164
Other income		
Amortization of contributions in aid of construction (Note 16)	3,091	3,262
Allowance for funds used during construction	1,840	1,060
Unrealized gain on interest rate swap (Note 26)	-	7,387
	4,931	11,709
Other expenses		
Interest on borrowings	6,791	5,527
Unrealized loss on interest rate swap (Note 26)	2,503	-
Net income for the year before net movement in regulatory balances	**11,744**	26,346
Net movement in Regulatory balances related to net income (Note 10(d))	(4,727)	(6,100)
Net income for the year after net movement in regulatory account balances	**7,017**	20,246
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)	(262)	3,366
Total comprehensive income for the year	**$ 6,755**	$ 23,612

The accompanying notes are an integral part of these financial statements.

Yukon Energy Corporation
Statement of Changes in Equity
(in thousands of Canadian dollars)

	Share Capital Number of shares	Share Capital $	Contributed surplus	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at December 31, 2021	**3,900**	**$ 39,000**	**$ 15,968**	**$ 82,684**	**$ -**	**$ 137,652**
Net income for the year and net movement in regulatory 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**
Net income for the year and net movement in regulatory account balances	-	-	-	7,017	-	7,017
Other comprehensive income	-	-	-	-	(262)	(262)
Transfer of re-measurement of defined benefit pension plans to retained earnings	-	-	-	(262)	262	-
Dividends (Note 27)	-	-	-	(27,260)	-	(27,260)
Balance at December 31, 2023	**3,900**	**$ 39,000**	**$ 15,968**	**$ 74,291**	**$ -**	**$ 129,259**

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	2023	2022
Operating activities		
Cash receipts from customers	$ 81,794	$ 80,096
Cash receipts from contributions in aid of construction	7,167	3,683
Cash paid to suppliers	(36,977)	(36,690)
Cash paid to employees	(15,434)	(14,212)
Cash receipts from insurance claim settlement	4,387	2,137
Interest paid	(6,657)	(5,669)
Cash provided by operating activities	**34,280**	29,345
Financing activities		
Net advance from (repayment to) line of credit	33,491	(1,694)
Dividends paid	(1,500)	-
Proceeds from long-term debt	7,425	17,991
Repayment of long-term debt	(6,900)	(6,614)
Lease payments	(178)	(1,172)
Cash provided by financing activities	**32,338**	8,511
Investing activities		
Additions to property, plant and equipment	(59,585)	(34,888)
Additions to intangible assets	(6,876)	(3,011)
Cash used in investing activities	**(66,461)**	(37,899)
Net increase (decrease) in cash	157	(43)
Cash, beginning of year	**3,061**	3,104
Cash, end of year (Note 11)	**$ 3,218**	$ 3,061

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 2023

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 2023

1. NATURE OF OPERATIONS - continued

b) Rate regulation - continued
In August 2023, the Utility filed a GRA for the years 2023 and 2024 requesting approval of revenue requirement and related rate increases of 6.25% for 2023 and 7.40% for 2024. The Utility expects a decision from the YUB in mid-2024.

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 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 reviewed and approved by the YUB is to maintain a capital structure of approximately 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 8, 2024.

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 2023

3. MATERIAL ACCOUNTING POLICY INFORMATION

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.

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 or if applicable over the useful life of the asset to which the contribution relates.

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.

Payment for Sales of Power are due within the month following service.

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.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2023

3. MATERIAL ACCOUNTING POLICY INFORMATION - continued

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.

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.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2023

3. MATERIAL ACCOUNTING POLICY INFORMATION - continued

f) Financial instruments - continued

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.

The fair value of the derivative related asset is calculated using market implied forward rates and discount factors, such as those for a Canadian dollar index, and which are specific to the credit risk and term to maturity of the asset. As the derivative related asset is fair valued using observable market data other than quoted prices for the asset, these inputs and the asset are categorized as level 2 in the fair value hierarchy.

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. A financial liability is derecognized when the obligation is discharged or cancelled, or expires.

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.

The fair value of the long-term debt is calculated using the net present value of principal and interest cash flows. The discount rates used in the present value calculation are obtained from the issuing banking institutions, and are specific to the credit risk and term to maturity associated with the long-term debt. As these discount rates are based on unobservable data, they are categorized as level 3 inputs in the fair value hierarchy.

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.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2023

3. MATERIAL ACCOUNTING POLICY INFORMATION - continued

g) Property, plant and equipment - continued

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
Land	No Depreciation
Buildings	20 to 55 years
Transportation	8 to 25 years
Other equipment	5 to 20 years

Depreciation commences when an asset is available for use. The estimated useful lives of the assets are based upon depreciation studies conducted periodically by the Utility and any changes in the estimated useful lives are accounted for prospectively.

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
Water Licensing	
Aishihik	5 years
Other hydro generation	17 to 25 years
Thermal Permit	3 years
Other Intangibles	5 years

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2023

3. MATERIAL ACCOUNTING POLICY INFORMATION - continued

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.

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.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2023

3. MATERIAL ACCOUNTING POLICY INFORMATION - continued

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 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.

k) Rate regulated accounting policies

Regulatory Deferral Account
Regulatory deferral accounts in these financial statements are accounted for differently than they would be in the absence of rate regulation; these are referred to throughout the statements as Regulatory Accounts. The Utility defers certain costs or revenues as regulatory debit balances or regulatory credit balances on the Statement of Financial Position and recognizes changes in the regulatory account balances in the net movement in regulatory account balances in the Statement of Operations and Other Comprehensive Income. The amounts recognized as regulatory account balances are expected to be recovered or refunded in future rates, based on approvals by the YUB. The recovery or settlement of regulatory 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 debit balances and regulatory credit balances as described in Note 1(b)).

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2023

3. MATERIAL ACCOUNTING POLICY INFORMATION - continued

k) Rate regulated accounting policies - continuted

i) Regulatory debit balances
Regulatory 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 credit balances
Regulatory 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 debits and credits, 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.

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.

Yukon Energy Corporation

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3. MATERIAL ACCOUNTING POLICY INFORMATION - continued

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.

p) Future application of changes in accounting standards
On May 16, 2022, Refinitiv Benchmark Services (UK) Limited (RBSL) announced the decision to cease the publication of Canadian Dollar Offered Rate (CDOR) after June 28, 2024. The transition is expected to impact derivatives and non-derivative instruments of the Utility.

The impacted derivatives include all interest rate swap agreements with TD Bank. The swaps have a fair value at year end of $2,405,000. The impacted non-derivatives include the long-term debt held with YDC, TD Bank, and others who have yet to transition, as well as the Minto Decommissioning Fund. As at year end, the total fair value of long-term debt is $178,176,000, while the total balance of the decommissioning fund is $3,028,000.

The transition will impact the rates used to calculate the fair value of the long-term debt and derivatives, and the interest rate earned by the decommissioning fund.

For the TD Bank derivatives, and most long-term debt, the banks providing the Utility with fair value percentages are expected to transition from the CDOR 1-month to the Canadian Overnight Repo Rate Average (CORRA). The transition is expected to impact the fair value amount of the interest rate swaps and the long-term debt as the CDOR rates were previously used to calculate fair value.

For the decommissioning fund held at CIBC, interest is currently based on the CDOR 3-month rate. As the basis for calculating cash flows from interest will change, the transition is expected to impact cash and deferred revenue related to the fund.

The interest rate benchmark reform has not resulted in changes to the Utility's risk management strategy. Management has been monitoring the transition and has assessed the overall risk arising from the transition as low. The full impact of the amendments is currently not known and will be assessed at conversion in 2024.

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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 financial assets – Note 3(f)(i)
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.

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.

Yukon Energy Corporation

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4. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS - continued

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.

Revenue – Notes 3(a), 10(a)(viii), 18 and 19
In years where the Utility has submitted a General Rate Application and the decision from the Yukon Utilities Board is outstanding, the Utility estimates the recovery amount of the GRA revenue requested.

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 Account Balances – Notes 1(b), 3(k) and 10
The Utility accounts for its regulatory 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 2023	December 31 2022
Trade accounts receivable		
Retail energy sales	$ 7,781	$ 8,426
Wholesale energy sales	5,061	6,404
Due from related parties (Note 22)	1,725	4,353
Other	2,492	1,221
	$ 17,059	$ 20,404

Included in Accounts receivable - Other is an amount of $831,000 (2022 - $496,000) related to GST ITC receivable.

At December 31, 2023, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	$ 11,982	$ 624	$ 4,463	$ 17,069
Allowance for doubtful accounts	-	-	(10)	(10)
	$ 11,982	$ 624	$ 4,453	$ 17,059

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

A reconciliation of the beginning and ending amount of allowance for doubtful accounts is as follows:

	December 31 2023	December 31 2022
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)

Yukon Energy Corporation

Notes to Financial Statements
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6. INVENTORIES

	December 31 2023	December 31 2022
Materials and supplies	$ 3,777	$ 3,562
Diesel fuel	1,192	1,312
Liquefied natural gas	103	70
	$ 5,072	$ 4,944

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
Costs:							
At December 31, 2021	$ 324,776	230,126	1,615	20,145	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	1,615	20,362	5,800	29,063	623,486
Additions	-	-	-	-	-	63,621	63,621
Transfers	10,622	15,686	-	1,618	1,052	(28,978)	-
Disposals	(3,467)	(140)	-	(50)	(27)	-	(3,684)
At December 31, 2023	$ 337,597	251,750	1,615	21,930	6,825	63,706	683,423
Accumulated depreciation:							
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
Depreciation	6,809	4,620	-	736	490		12,655
Disposals	(2,521)	(95)	-	(49)	(27)		(2,692)
At December 31, 2023	$ 55,428	47,383	-	6,826	3,340	-	112,977
Net Book Value:							
At December 31, 2022	$ 279,302	193,346	1,615	14,223	2,923	29,063	520,472
At December 31, 2023	$ 282,169	204,367	1,615	15,104	3,485	63,706	570,446

The total AFUDC capitalized for 2023 was $1,840,000 (2022 - $1,060,000). The AFUDC rate for 2023 was 2.77% (2022 - 2.61%).

Yukon Energy Corporation

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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	Water Licensing	Thermal Permit	Other Intangibles	Work in Progress	Total
Costs:									
At December 31, 2021	$	1,303	443	6,955	1,288	-	-	13,450	23,439
Additions		-						3,904	3,904
Transfers		278			-			(278)	
Disposals		(396)			(805)				(1,201)
At December 31, 2022	$	1,185	443	6,955	483			17,076	26,142
Additions		-	-	-	-			7,247	7,247
Transfers		258			3,903			(4,161)	-
Disposals		(259)			(147)				(406)
At December 31, 2023	$	1,184	443	6,955	4,239	-	-	20,162	32,983
Accumulated amortization:									
At December 31, 2021	$	657	443	2,614	830				4,544
Amortization		235	-	554	339				1,128
Disposals		(396)	-	-	(805)				(1,201)
At December 31, 2022	$	496	443	3,168	364	-	-	-	4,471
Amortization		233	-	492	820				1,545
Disposals		(228)	-	-	(147)				(375)
At December 31, 2023	$	501	443	3,660	1,037	-	-	-	5,641
Net Book Value:									
At December 31, 2022	$	689	-	3,787	119	-	-	17,076	21,671
At December 31, 2023	$	683	-	3,295	3,202	-	-	20,162	27,342

Additions to Financial Software, Water Licensing, Thermal permit and Other Intangibles were almost exclusively internally generated. Additions to Software was almost exclusively externally purchased.

The table above has been updated to present work in progress separately from Intangible Assets that are in service. Work in Progress consists of Software $64,000 (2022 – $6,000), Financial Software $118,000 (2022 – $100,000), Water Licensing $19,576,000 (2022 – $16,970,000), Thermal Permit $138,000 (2022 – $0) and Other Intangibles $266,000 (2022 - $0).

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9. LEASES

The Utility leases industrial land and building facilities. During the year the Utility renewed a building lease for a term of five years. In 2022 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 2022.

Right-of-use assets consist of land of $1,063,000 (2022 - $1,139,000) and building of $713,000 (2022 - $92,000).

	December 31 2023	December 31 2022
Right-of-use assets		
As at January 1	$ 1,231	$ 234
Additions	750	1,181
Depreciation expense	(205)	(184)
As at December 31	$ 1,776	$ 1,231
Lease liabilities		
Lease liabilities	$ 855	$ 265
Less: current portion	160	130
Non-current portion	$ 695	$ 135
Maturity analysis		
Less than one year	$ 205	$ 137
One to five years	772	145
More than five years	-	-
Total undiscounted lease liabilities	$ 977	$ 282
Amounts recognized in net income		
Depreciation expense on right-of-use assets	$ (205)	$ (184)
Interest expense on lease liabilities	$ (18)	$ (8)
Expense relating to short-term leases	$ (3,556)	$ (3,203)

Yukon Energy Corporation

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10. REGULATORY ACCOUNTS

a) Regulatory 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, 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
Costs incurred	1,510	3,363	-	-	555	-	5,428
Regulatory provision	-	(413)	-	(98)	(411)	2,193	1,271
Disposals	650	(423)	-	-	-	(2,112)	(1,885)
Contributions received	-	(453)	-	-	-	-	(453)
At December 31, 2023	$ 18,967	$ 10,458	255	$ 1,301	$ 4,745	$ 3,246	$ 38,972
Accumulated amortization:							
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
Amortization	1,074	321	51	138	205	-	1,789
Disposals	650	(349)	-	-	-	-	301
At December 31, 2023	$ 4,763	$ 1,139	$ 127	$ 248	$ 1,462	$ -	$ 7,739
Net book value:							
At December 31, 2022	$ 13,768	$ 7,217	$ 179	$ 1,289	$ 3,344	$ 3,165	$ 28,962
At December 31, 2023	$ 14,204	$ 9,319	$ 128	$ 1,053	$ 3,283	$ 3,246	$ 31,233
Net increase (decrease) in regulatory debit balances (which are recognized in the net movement in regulatory account balances related to net income on the Statement of Operations and Other Comprehensive Income):							
December 31, 2022	$ (1,384)	$ 426	$ (51)	$ 372	$ 1,390	$ 1,842	$ 2,595
December 31, 2023	$ 436	$ 2,102	$ (51)	$ (236)	$ (61)	$ 81	$ 2,271
Remaining recovery years							
At December 31, 2022	1 to 5 years	1 to 31 years	4 years	5 to 10 years	Indeterminate	1 year	
At December 31, 2023	1 to 5 years	1 to 30 years	3 years	3 years	Indeterminate	1 year	
Absent rate regulation, net income for the year and net movement in regulatory account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:							
December 31, 2022	$ 1,384	$ (426)	$ 51	$ (372)	$ (1,390)	$ (1,842)	$ (2,595)
December 31, 2023	$ (436)	$ (2,102)	$ 51	$ 236	$ 61	$ (81)	$ (2,271)

Yukon Energy Corporation

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10. REGULATORY ACCOUNTS - continued

a) Regulatory debit balances - continued

	Carry Forward	Vegetation Management (vii)	2023/24 GRA (viii)	2021 GRA (ix)	IPP Purchase Costs (x)	Total
Cost:						
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
Costs incurred	5,428	-	-	-	-	5,428
Regulatory provision	1,271	-	5,667	-	-	6,938
Disposals	(1,885)	-	-	(1,957)	-	(3,842)
Contributions received	(453)	-	-	-	-	(453)
At December 31, 2023	$ 38,972	$ 2,216	$ 5,667	$ 682	$ 26	$ 47,563
Accumulated amortization:						
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
Amortization	1,789	222	-	1,957	-	3,968
Disposals	301	-	-	(1,957)	-	(1,656)
At December 31, 2023	$ 7,739	$ 1,552	$ -	$ -	$ -	$ 9,291
Net book value:						
At December 31, 2022	$ 28,962	$ 886	$ -	$ 2,639	$ 26	$ 32,513
At December 31, 2023	$ 31,233	$ 664	$ 5,667	$ 682	$ 26	$ 38,272
Net increase (decrease) in regulatory debit balances (which are recognized in the net movement in regulatory account balances on the Statement of Operations and Other Comprehensive Income):						
December 31, 2022	$ 2,595	$ (221)	$ -	$ (1,691)	$ 26	$ 709
December 31, 2023	$ 2,271	$ (222)	$ 5,667	$ (1,957)	$ -	$ 5,759
Remaining recovery years						
At December 31, 2022		4 years	N/A	1 year	Indeterminate	
At December 31, 2023		3 years	2 years	1 year	Indeterminate	
Absent rate regulation, net income for the year and net movement in regulatory account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:						
December 31, 2022	$ (2,595)	$ 221	$ -	$ 1,691	$ (26)	$ (709)
December 31, 2023	$ (2,271)	$ 222	$ (5,667)	$ 1,957	$ -	$ (5,759)

(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.

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10. REGULATORY ACCOUNTS - continued

a) Regulatory 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. During the year, $413,000 (2022 - $903,000) was transferred to the regulatory credit balance class hearing reserve (Note 10(b)(ii)) and disallowed costs of $423,000 (2022 - $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 and amortization of the forecast 2020 accumulated balance of $2,048,000 over ten years ($205,000 per year). In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(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 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 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) 2023/24 GRA
The Utility recognizes a regulatory 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 2023/24 GRA, $5,667,000 was recognized for increase in revenue requirement. This amount is 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.

(ix) 2021 GRA
The Utility recognizes a regulatory 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 February 2023, less amounts received from customers. 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 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, 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
Cost incurred	-	-	-	(653)	-	-	(653)
Regulatory provision	4,500	(166)	5,791	-	(96)	1,348	11,377
At December 31, 2023	$ 16,102	$ (1,047)	$ 15,687	$ 2,037	$ 4,964	$ 3,874	$ 41,617
Accumulated amortization:							
At December 31, 2021	$ 7,686	$ 973	$ -	$ -	$ -	$ -	$ 8,659
Amortization	262	-	-	-	-	-	262
Disposals	-	(973)	-	-	-	-	(973)
At December 31, 2022	$ 7,948	$ -	$ -	$ -	$ -	$ -	$ 7,948
Amortization	262	-	-	-	-	-	262
Disposals	-	-	-	-	-	-	-
At December 31, 2023	$ 8,210	$ -	$ -	$ -	$ -	$ -	$ 8,210
Net book value:							
At December 31, 2022	$ 3,654	$ (881)	$ 9,896	$ 2,690	$ 5,060	$ 2,526	$ 22,945
At December 31, 2023	$ 7,892	$ (1,047)	$ 15,687	$ 2,037	$ 4,964	$ 3,874	$ 33,407
Net (increase) decrease in regulatory credit balances (which are recognized in the net movement of regulatory balances related to net income on the Statement of Operations and Other Comprehensive Income):							
December 31, 2022	$ 262	$ 653	$ (7,114)	$ 49	$ 96	$ (692)	$ (6,746)
December 31, 2023	$ (4,238)	$ 166	$ (5,791)	$ 653	$ 96	$ (1,348)	$ (10,462)
Remaining recovery years							
At December 31, 2022	14 years	Indeterminate	Indeterminate	Indeterminate	45 years	51 years	
At December 31, 2023	13 years	Indeterminate	Indeterminate	Indeterminate	44 years	50 years	
Absent rate regulation, net income for the year end and net movement in regulatory balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:							
December 31, 2022	$ (262)	$ (653)	$ 7,114	$ (49)	$ (96)	$ 692	$ 6,746
December 31, 2023	$ 4,238	$ (166)	$ 5,791	$ (653)	$ (96)	$ 1,348	$ 10,462

Yukon Energy Corporation

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December 31 2023

10. REGULATORY ACCOUNTS - continued

b) Regulatory credit balances - continued

	Carry Forward	Defined Benefit Pension (vii)	Total
Cost:			
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
Cost incurred	(653)	-	(653)
Regulatory provision	11,377	23	11,400
Disposals	-	-	-
At December 31, 2023	$ 41,617	$ 86	$ 41,703
Accumulated amortization:			
At December 31, 2021	$ 8,659	$ -	$ 8,659
Amortization	262	-	262
Disposals	(973)	-	(973)
At December 31, 2022	$ 7,948	-	$ 7,948
Amortization	262	-	262
Disposals	-	-	-
At December 31, 2023	$ 8,210	$ -	$ 8,210
Net book value:			
At December 31, 2022	$ 22,945	$ 63	$ 23,008
At December 31, 2023	$ 33,407	$ 86	$ 33,493
Net (increase) decrease in regulatory credit balances (which are recognized in the net movement of regulatory balances related to net income on the Statement of Operations and Other Comprehensive Income):			
December 31, 2022	$ (6,746)	$ (63)	$ (6,809)
December 31, 2023	$ (10,462)	$ (23)	$ (10,485)
Remaining recovery years			
At December 31, 2022		Indeterminate	
At December 31, 2023		Indeterminate	
Absent rate regulation, net income for the year end and net movement in regulatory balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:			
December 31, 2022	$ 6,746	$ 63	$ 6,809
December 31, 2023	$ 10,462	$ 23	$ 10,485

(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, and a gain on insurance proceeds related to damage to the Lewes River Boat lock in 2021 which is not yet being amortized as it has not yet received regulatory approval. In the absence of rate regulation, IFRS requires the gain to have been fully recognized as income in the year received.

Yukon Energy Corporation

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10. REGULATORY ACCOUNTS - continued

b) Regulatory credit balances - continued

(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 less $416,000 (2022 - $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.

(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 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 credit balance.

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2023

10. REGULATORY ACCOUNTS - continued

b) Regulatory credit balances - continued

(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 credit balance.

(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 $5,428,000 (2022 - $4,527,000) and regulatory account credit balances of $653,000 (2022 - $49,000).

(d) Net movement in regulatory balances related to net income

Net movement in regulatory balances related to net income is $4,727,000 (2022 - $6,100,000) represents the adjustment to net income for the year before net movement in regulatory balances for the effects of rate regulation in accordance with IFRS 14. The net movement figure is comprised of an increase of $5,759,000 for regulatory account debit balances and an increase of $10,485,000 for regulatory account credit balances for rate regulation compared to the amounts that are recognized under IFRS. The net movement figure for 2022 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 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 $47.7 million (2022 - $14.1 million). The Utility has cash balances with the same financial institution of $3.2 million (2022 - $3.1 million). The Utility's bank indebtedness is comprised of:

	December 31 2023	December 31 2022
Line of credit	$ 47,675	$ 14,184
Less: bank balances	3,218	3,061
	$ 44,457	$ 11,123

For the purposes of the statement of cash flows, the line of credit is classified as financing activities as it is used to fund construction work in progress. 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 2023	December 31 2022
Trade payables	$ 19,376	$ 13,951
Due to related parties (Note 22)	993	1,422
Employee compensation	1,006	1,151
Other	269	261
	$ 21,644	$ 16,785

13. CONSTRUCTION FINANCING

	December 31 2023	December 31 2022
Construction financing, due December 31, 2024 bearing interest at 5.444% approved to a maximum of $10 million	$ 10,000	$ -
Construction financing, due December 31, 2024 bearing interest at 5.444% approved to a maximum of $27.26 million	27,260	-
Construction financing, due December 31, 2024 bearing interest at 5.444% approved to a maximum of $8.4 million	8,400	-
Construction financing, due December 31, 2024 bearing interest at 5.444% approved to a maximum of $14 million	12,617	-
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
	$ 58,277	$ 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. Two new constuction financing agreements ($10.0M and $27.26M) have been added in 2023 to assist with working requirements for capital projects. The prior year debt was extinguished and replaced with new debt with no impact on cash flows.

Yukon Energy Corporation

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December 31 2023

14. LONG-TERM DEBT

The Utility's long-term debt is unsecured and summarized as follows:

	December 31 2023	December 31 2022
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	$ 59,304	$ 62,988
$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)	17,857	18,194
$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	14,269	15,109
$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
$6,425,000 term note bearing interest at 4.10%. Payable in quarterly installments of $103,009 interest and principal with the balance due December 21, 2048 (ii)	6,425	-
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 (iii)	6,987	7,413
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 (iv)	20,135	20,843
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 (v)	5,877	6,089
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 (vi)	4,333	4,488
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 (vii)	7,079	7,301

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2023

14. LONG-TERM DEBT - continued

	December 31 2023	December 31 2022
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 (viii)	$ 17,598	$ 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
Champagne and Aishihik First Nations		
On July 21, 2023, the Utility entered into $1,000,000 Long-term debt associated with the installation of the third hydro turbine at the Aishihik Hydroelectric Generating Station (AGS) and due on July 31, 2048. Interest rate is the rate of return on equity and interest payable annually (ix)	1,000	-
Long-term debt	185,476	184,951
Less: current portion	62,733	6,900
	$ 122,743	$ 178,051

(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) $6,425,000 Flexible Term Note
On December 21, 2023, Yukon Development Corporation entered into a loan and interest rate swap with TD Bank to support the Utility to maintain required regulatory debt ratio of 60%. The Utility will make payments of principal and interest to YDC in the amounts of each payment owing by YDC to the TD Bank.

(iii) 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.

Yukon Energy Corporation

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December 31 2023

14. LONG-TERM DEBT - continued

(iv) 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.

(v) 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.

(vi) 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.

(vii) 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.

(viii) 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.

(ix) Champagne and Aishihik First Nations debt
On July 21, 2023, the Utility entered into a long-term debt agreement with Champagne and Aishihik First Nation associated with the installation of the third hydro turbine at the AGS. The debt matures July 31, 2048. The per annum interest rate is the actual final rate of return on equity for the Utility's regulatory income for the actual year most recently filed with the YUB under section 25(1) of the *Public Utilities Act*.

Long-term debt repayment
Scheduled repayments for all long-term debt are as follows:

2024	62,733
2025	7,458
2026	3,571
2027	3,646
2028	3,723
Thereafter	104,345
	$ 185,476

Yukon Energy Corporation

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14. LONG-TERM DEBT - continued

The change in long-term debt arising from financing activities during the year related to principal repayments of $6,900,000 (2022 - $6,614,000) and the issuance of additional debt in the amount of $7,425,000 (2022 - $17,991,000).

Fair value
The fair value of long-term debt at December 31, 2023 is $178,176,000 (2022 - $174,539,000). 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.

15. POST-EMPLOYMENT BENEFITS

Characteristics of benefit plans
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 currently not required to make any special payments.

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.

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 2023, these were $673,000 (2022 - $559,000).

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 2023	December 31 2022
Present value of benefit obligations		
Balance, beginning of year	$ 22,536	$ 28,781
Employee contributions	45	43
Current service cost	120	409
Interest cost	1,131	864
Benefits paid	(1,022)	(827)
Actuarial (gains) losses on experience	(583)	319
Actuarial (gains) on demographic assumptions	(48)	(6)
Actuarial losses (gains) on financial assumptions	1,715	(7,047)
Balance, end of year	$ 23,894	$ 22,536
Fair value of plan assets		
Balance, beginning of year	21,785	24,611
Interest income on plan assets	1,093	736
Gains (losses) on plan assets	818	(3,376)
Employee contributions	45	43
Employer contributions	357	668
Benefits paid	(1,022)	(827)
Administrative costs	(70)	(70)
Balance, end of year	$ 23,006	$ 21,785
Effect of asset ceiling	76	76
Net defined benefit liability	$ 964	$ 827

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2023

15. POST-EMPLOYMENT BENEFITS - continued

Components of benefit plan cost:

	December 31 2023	December 31 2022
Current service cost	$ 120	$ 409
Interest cost	1,131	864
Interest income on plan assets	(1,093)	(736)
Administrative costs	70	70
Interest cost on effect of asset ceiling	4	2
Defined benefit expense in Statement of Operations	232	609
Defined contribution expense	673	559
Total benefit expense in Statement of Operations	$ 905	$ 1,168
Actuarial losses (gains) on obligation	1,084	(6,734)
(Gains) losses on plan assets	(818)	3,376
Effect of asset ceiling	(4)	(8)
Total re-measurements included in Other Comprehensive Income	$ 262	$ (3,366)
Total benefit costs recognized in Statement of Operations and Other Comprehensive Income	$ 1,167	$ (2,198)

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, 2023	December 31, 2022
Equities	40.7%	43.8%
Fixed income securities	40.5%	31.5%
Real estate	18.8%	24.7%

Significant assumptions:

	December 31, 2023	December 31, 2022
Discount rate - accrued benefit obligation	4.60%	5.10%
Assumed rate of compensation increase	3.10%	3.10%
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, 2023

Assumption	+1%	-1%	+1%	-1%
Discount rate	-11%	13%	$ (2,605)	$ 3,173
Salary growth	0.3%	-0.3%	67	(65)
Pension growth	13%	-11%	3,053	(2,612)
Life expectancy (1 year movement)	3%	-3%	607	(618)

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)

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 12.3 years (2022 - 12.1 years). The Utility expects to make payments of $209,000 (2022 - $230,800) 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, 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
Additions	3,843	-	524	-	4,367
At December 31, 2023	$ 103,583	$ 89,730	$ 12,422	$ 1,739	$ 207,474
Accumulated amortization:					
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
Amortization	1,249	1,602	197	43	3,091
At December 31, 2023	$ 12,863	$ 19,464	$ 3,339	$ 1,639	$ 37,305
Net book value:					
At December 31, 2022	$ 88,126	$ 71,868	$ 8,756	$ 143	$ 168,893
At December 31, 2023	$ 90,720	$ 70,266	$ 9,083	$ 100	$ 170,169

17. DEFERRED REVENUE

	Customer Contributions	IPP Contracts	Decommissioning Fund	Total
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
Additions	459	1,822	154	2,435
Revenue recognized in Sales of Power and Other Revenue	(1,303)	(365)	-	(1,668)
At December 31, 2023	$ 14,704	$ 1,733	$ 3,029	$ 19,466

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

The following table includes revenue expected to be recognized in the future related to performance obligations that are unsatisfied as at December 31, 2023:

	Less than 1 year	Between 1 and 5 years	More than 5 years	Total
Customer contracts	$ 1,295	$ 6,475	$ 6,934	$ 14,704
IPP contracts	556	242	935	1,733
Decommissioning fund	-	-	3,029	3,029
	$ 1,851	$ 6,717	$ 10,898	$ 19,466

At December 31, 2022, the current portion of deferred revenue of $1,380,000 consisted of customer contracts ($1,315,000) and IPP contracts ($65,000).

18. SALES OF POWER

	2023	2022
Wholesale	$ 46,665	$ 46,993
Industrial	16,576	20,753
General service	10,793	8,193
Residential	4,084	4,079
Secondary sales	227	365
Sentinel and street lights	113	137
	$ 78,458	$ 80,520

19. OTHER REVENUE

The Utility recognized $4,500,000 (2022 - $0) related to a gain on insurance proceeds (Note 10(b)(i)) and $365,000 (2022 - $3,201,000) in other revenue related to IPP contracts (Note 17).

In October 2021 efforts to reduce flooding at Marsh Lake resulted in permanent damage to the Lewes River Boat Lock. Insurance proceeds were received in 2023 in the amount of $5,520,000. Net of the insurance deductible and other costs, proceeds totaled $4,500,000. Insurance proceeds were allocated to the removal of the Lewes River Boat Lock and towards a new upgraded boat lock at the Lewes Dam, which is part of a larger upgrade project. Construction is expected to commence in 2024.

Yukon Energy Corporation

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20. OPERATIONS AND MAINTENANCE EXPENSES

	2023	2022
Fuel	$ 11,138	$ 11,642
Wages and benefits	7,285	6,516
Regulatory account expenses (Note 10(c))	6,083	4,576
Rent	5,242	3,028
Contractors	3,825	6,760
Materials and consumables	1,713	2,099
Loss on asset disposals	1,024	61
Travel	533	409
Communication	93	87
	$ 36,936	$ 35,178

21. ADMINISTRATION EXPENSES

	2023	2022
Wages and benefits	$ 7,879	$ 7,098
Insurance and taxes	3,060	2,702
External labour	2,619	1,956
Materials, consumables and general	2,472	1,684
Licences and fees	1,027	1,083
Travel	362	224
Board fees	156	109
	$ 17,575	$ 14,856

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.

Yukon Energy Corporation

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22. RELATED PARTY TRANSACTIONS - continued

The following table summarizes the Utility's related party transactions with YDC for the year:

	2023	2022
Revenue		
Sales of service	$ -	$ 4
Rate subsidy	831	$ 924
Operating expenses		
Interest expense	$ 4,741	$ 3,998
Dividends	$ 27,260	$ 11,500
Other receipts		
Construction financing	$ 37,260	$ -
Long-term debt	6,425	-
Other payments/deductions		
Repayment of long-term debt	$ 4,860	$ 4,860

At the end of the year, the amounts receivable from and due to related parties are as follows:

	December 31 2023	December 31 2022
YDC		
Accounts receivable	$ 1,485	$ 4,144
Accounts payable	993	1,012
Construction financing	58,277	21,017
Dividends payable	-	11,500
Current portion of long-term debt	60,631	4,860
Long-term debt	61,695	115,901
YG		
Accounts receivable	$ 240	$ 209
Accounts payable	-	410

Included in Accounts receivable from YDC is an amount of $1,192,000 for capital projects funded by the federal government, which are administered through YG and YDC (2022 - $3,992,000). 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	2023	2022
Short-term employee benefits	$ 1,975	$ 1,823
Post-employment benefits	110	145
	$ 2,085	$ 1,968

Yukon Energy Corporation

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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, 2023 as the product or service had not been provided. The following table summarizes the nature of the commitments:

Commitments*	2023	2022
Property, plant and equipment	$ 44,353	$ 66,059
Other products or services	8,110	5,546
Intangible assets	1,747	717
	$ 54,210	$ 72,322

* Comparative information has been disaggregated by the nature of the commitment in order to provide additional information and to align with the current year's presentation.

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, 2023 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, 2023, 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.

Yukon Energy Corporation

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26. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

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.

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, 2023 was an asset of $2,405,000 (2022 - asset of $4,908,000). The decrease in the fair value in 2023 of $2,503,000 (2022 – increase $7,387,000) is recognized on the Statement of Operations and Other Comprehensive Income as an unrealized loss. 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 $5,844,000 (2022 - $6,371,000).

The Utility has access to a line of credit. As at January 1, 2023, the line of credit was $65.0 million. Effective December 18, 2023, the line of credit was increased temporarily to $100.0 million. The temporary increase expires June 30, 2024. The account accrues interest on withdrawals at prime rate minus 0.75% (2022 - 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 2023	December 31 2022
Accounts receivable	17,059	20,404
	$ 17,059	$ 20,404

Credit risk on accounts receivable is generally considered minimal as the Utility has experienced insignificant bad debt in prior years. 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, 2023 is $5,077,000 (2022 - $4,957,000), of which $4,015,000 (2022 - $3,851,000) pertains to one customer. This customer is currently in receivership and working on a potential mine sale process. If the sale process is not successful, the receiver will commence with asset liquidation. The recovery of any amount owing will not occur until after the sale or liquidation is completed. The timing and certainty of a full recovery is unknown, and a wide range of outcomes are possible. However, based on management's judgment and assessment, as at December 31, 2023, this amount continues to be considered fully collectible. Therefore, no allowance provision (2022 – $nil) has been recognized.

Yukon Energy Corporation

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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, 2023:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related asset	-	$2,405	-	$2,405
Long-term debt	-		$178,176	$178,176

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

Yukon Energy Corporation

Notes to Financial Statements
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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 regulatory capital structure at a ratio of approximately 60% debt and 40% equity. The capital structure ratio has been reviewed and accepted by the YUB for rate setting purposes.

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 16). 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 2023	December 31 2022
Long-term debt due within one year	$ 62,733	$ 6,900
Long-term debt	122,743	178,051
Total debt	185,476	184,951
Add decommissioning fund (Note 17)	3,029	2,875
Total debt to include in the calculation	$ 188,505	$ 187,826
Share capital	39,000	39,000
Contributed surplus	15,968	15,968
Retained earnings	74,289	94,796
Total shareholder's equity	$ 129,257	$ 149,764
Total capitalization	$ 317,762	$ 337,590
Total debt to total capitalization	59 %	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 $27,260,000 (2022 - $11,500,000). The dividend was converted to Construction Financing (see Note 13). Of the prior year dividend, $10,000,000 was also converted to Construction Financing and the remaining $1,500,000 was paid in cash.

TAB 11
ORDERS IN COUNCIL

PUBLIC UTILITIES ACT

RATE POLICY DIRECTIVE (1995)

O.I.C. 1995/090

Effective Date:

May 29, 1995

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

DÉCRET 1995/090

Date d'entrée en vigueur :

29 mai 1995

O.I.C. 1995/090
PUBLIC UTILITIES ACT

RATE POLICY DIRECTIVE (1995)

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.

DÉCRET 1995/090
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

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.

Commissioner of the Yukon/Commissaire du Yukon

RATE POLICY DIRECTIVE (1995)

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INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

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RATE POLICY DIRECTIVE (1995)

1. Interpretation

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* »

"renewable generation" means generation of electricity from renewable sources, including hydro, wind, solar,

INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

1. Définitions

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*" geothermal and biomass sources; *« production d'énergie renouvelable »*

["renewable generation" added by O.I.C. 2021/16]

"**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* »

2. Normal return on equity

(1) Subject to subsection (2), the Board must include in the rates of Yukon Energy Corporation and the Yukon Electrical Company Limited provision to recover a fair return on their equity used to finance their rate base.

(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]

2.1 Retail and major industrial rate adjustments

(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)

« **gaz naturel** » S'entend notamment du gaz naturel liquéfié. "*natural gas*"

*[« **gaz naturel** » ajoutée par Décret 2018/220]*

« 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"*

*[« **production d'énergie renouvelable** » ajoutée par Décret 2021/16]*

« **province** » S'entend d'une province au sens de la *Loi d'interprétation*. "*province*"

2. Rendement normal sur la valeur nette

(1) Sous réserve du paragraphe 2, la Régie doit prévoir dans les tarifs de la Société d'énergie du Yukon et de la Yukon Electrical Company Limited les mesures pour réaliser un rendement équitable sur leur valeur nette utilisé pour financer leurs tarifs de base.

(2) La Régie 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 Régie, 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]

[Article 2 modifié par Décret 2021/16]

2.1 Ajustements tarifaires pour les clients au détail et industriels majeurs

(1) La Régie 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]

[Paragraphe 2.1(1) modifié par Décret 2021/16]

(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]

3. Normal principles to apply

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.

4. Retail rates: non-government customers

(1) The Board must fix rates for retail customers, other than government customers, in accordance with the following rate policy for Yukon,

(a) the rates for non-government retail customers must be sufficient to recover costs that are not to be recovered from government customers or from major industrial customers;

(b) rates for each class of non-governmental retail customer must be the same throughout the Yukon without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited customers;

(2) The Board must fix a runoff rate block for each non-government retail customer class applicable to all consumption by each customer of the class in excess of a specified consumption level per billing period, and such specified consumption level per customer is not to be less than 1,000 kWh for residential non-government retail customers and 2,000 kWh for general service non-government retail customers.

[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]

3. Application des principes normaux

Sauf indication contraire dans les présentes instructions ou dans la Loi, la Régie 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.

[Article 3 modifié par Décret 2021/16]

4. Tarifs au détail pour les clients non-gouvernementaux

(1) La Régie fixe les tarifs pour les clients au détail non-gouvernementaux selon la politique tarifaire suivante pour le Yukon :

a) les tarifs pour les clients non-gouvernementaux doivent suffire à générer les recettes nécessaires afin de recouvrer les coûts, lesquels ne doivent pas être récupérés des clients gouvernementaux ou des clients industriels majeurs;

b) les tarifs pour chaque catégorie de clients au détail non-gouvernementaux s’appliquent uniformément à la grandeur du Yukon et sans distinction entre la Société d’énergie du Yukon et la Yukon Electrical Company Limited.

(2) La Régie 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) 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.

(3) La Régie 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.

[Article 4 modifié par Décret 2021/16]

5. Retail rates: government customers

(1) The Board must fix rates for government customers in accordance with the following power rate policy for Yukon

(a) rates for government customers may be adjusted so as to simplify the rate structure and make the rates more consistent throughout Yukon;

(b) the rate for government customers in a community may not be lower than the rate for similar service to non-government retail customers in that community.

(2) Upon application of Yukon Energy Corporation, The Yukon Electrical Company Limited, or a customer, the Board must determine whether a customer is or is not a government customer.

5. Tarifs au détail pour les clients gouvernementaux

(1) La Régie fixe les tarifs pour les clients gouvernementaux selon la politique tarifaire énergétique du Yukon qui suit :

a) les tarifs pour les clients gouvernementaux peuvent être ajustés aux fins de simplifier la structure tarifaire et d'uniformiser les tarifs à la grandeur du Yukon;

b) le tarif pour les clients gouvernementaux dans une agglomération ne peut être moindre que le tarif pour un service semblable pour les clients au détail non-gouvernementaux dans cette agglomération.

(2) À la demande de la Société d'énergie du Yukon ou de la Yukon Electrical Company Limited, ou d'un client, la Régie prend une décision sur le statut de client gouvernemental d'un client.

[Article 5 modifié par Décret 2021/16]

6. Rates - major and isolated industrial customers

(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]

6. Tarifs pour les clients industriels majeurs et isolés

(1) La Régie 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) 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]

7. Wholesale rates

The Board must fix rates of Yukon Energy Corporation for the wholesale power customer in accordance with the following rate policy for Yukon:

(a) Yukon Energy Corporation shall sell electricity to The Yukon Electrical Company Limited at the same demand rate and the same energy rate throughout the Yukon and those rates must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers;

(b) the wholesale rate to The Yukon Electrical Company Limited shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein.

8. Fuel Price adjustment

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

(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 Régie lorsqu’elle établit les tarifs pour d’autres clients.

(3) Malgré le paragraphe (1), la Régie 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) modifié par Décret 2014/23]

[Paragraphe 6(3) remplacé par Décret 2018/220]

[Article 6 modifié par Décret 2021/16]

7. Tarifs de gros

La Régie doit déterminer les tarifs facturés par la Société d’énergie du Yukon au client en gros selon la politique tarifaire du Yukon qui suit :

a) la Société d’énergie du Yukon vend de l’électricité à la Yukon Electrical Company Limited au même tarif de demande et au même tarif d’énergie à la grandeur du Yukon et ces tarifs doivent suffire à la Société d’énergie du Yukon pour recouvrer les coûts qui ne sont pas recouverts de ses autres clients;

b) le tarif de gros facturé à la Yukon Electrical Company Limited comprend les mesures appropriées pour permettre à la Société d’énergie du Yukon de recouvrer ses coûts de service au détail et ses coûts de service aux clients industriels majeurs au moyen de tarifs qui s’appliquent à ces services en vertu des présentes.

[Article 7 modifié par Décret 2021/16

8. Ajustement du prix du combustible

La Régie 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 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]

9. Fuel costs and low water deferral account

(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 renewable generation. *« disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable »*

(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.

(3) For the purpose of subsection (2), the Board must determine the forecast fuel costs for a financial year of Yukon Energy Corporation by

(a) forecasting the amount of renewable generation available to contribute to meeting forecast customer requirements, based on long-term average annual renewable source availability;

(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

(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.

une demande particulière à la Régie pour obtenir son autorisation.

[Article 8 modifié par Décret 2018/220]

[Article 8 modifié par Décret 2021/16]

9. Coûts du combustible et compte de report de bas niveau d'eau

(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 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) 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) 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) 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) 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) 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:

(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 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 source availability is less than long-term average annual renewable source availability.

(4) Après chaque exercice de la Société d’énergie du Yukon, la Régie examine et approuve la différence entre les éléments suivants :

a) les coûts du combustible pour la quantité de production d’énergie thermique nécessaire pour répondre aux besoins réels de clients pour l’exercice 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 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) 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.

[Section 9 added by O.I.C 2021/16]

(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.

[Article 9 ajouté par Décret 2021/16]

10. Recovery of costs for demand-side management program

(1) In this section

"demand-side management program" means 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. *« 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.

10. Recouvrement des coûts d'un programme de gestion axée sur la demande

(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 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) 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.

[Section 10 added by O.I.C 2021/16]

(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.

[Article 10 ajouté par Décret 2021/16]

11. Recovery of costs for renewable generation project planning or development

(1) 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 plan or develop renewable generation projects.

(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.

[Section 11 added by O.I.C 2021/16]

11. Recouvrement des coûts de planification ou de développement de projets de production d'énergie renouvelable

(1) 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 planifier ou développer des projets de production d'énergie renouvelable.

(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.

[Article 11 ajouté par Décret 2021/16]

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

DIRECTION TO THE YUKON UTILITIES BOARD (INDEPENDENT POWER PRODUCTION)

O.I.C. 2019/025

Effective Date:

January 25, 2019

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INSTRUCTION À L'INTENTION DE LA RÉGIE DES ENTREPRISES DE SERVICE PUBLIC (PRODUCTION INDÉPENDANTE D'ÉNERGIE)

DÉCRET 2019/025

Date d'entrée en vigueur :

25 janvier 2019

O.I.C. 2019/025
PUBLIC UTILITIES ACT

DIRECTION TO THE YUKON UTILITIES BOARD (INDEPENDENT POWER PRODUCTION)

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.

DÉCRET 2019/025
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INSTRUCTION À L'INTENTION DE LA RÉGIE DES ENTREPRISES DE SERVICE PUBLIC (PRODUCTION INDÉPENDANTE D'ÉNERGIE)

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.

Commissioner of Yukon/Commissaire du Yukon

DIRECTION TO THE YUKON UTILITIES BOARD (INDEPENDENT POWER PRODUCTION)

INSTRUCTION À L'INTENTION DE LA RÉGIE DES ENTREPRISES DE SERVICE PUBLIC (PRODUCTION INDÉPENDANTE D'ÉNERGIE)

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DIRECTION TO THE YUKON UTILITIES BOARD (INDEPENDENT POWER PRODUCTION)

1 Definitions

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

INSTRUCTION À L'INTENTION DE LA RÉGIE DES ENTREPRISES DE SERVICE PUBLIC (PRODUCTION INDÉPENDANTE D'ÉNERGIE)

1 Définitions

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*" 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* »

"**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* »

« **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 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*"

2 Costs recoverable by electrical utility

(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.

(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 Coûts recouvrables par un service public d'électricité

(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) 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.

3 Price for electricity under electricity purchase agreement

(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.

3 Prix de l'électricité en vertu du contrat d'achat d'électricité

(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.

4 Annual CPI adjustment

(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.

(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.

5 Compensation

(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.

6 Term of electricity purchase agreement

The term of an electricity purchase agreement is to be at least 20 years.

4 Rajustement annuel en fonction de l'IPC

(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) 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.

5 Indemnisation

(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.

6 Durée du contrat d'achat d'électricité

La durée d'un contrat d'achat d'électricité est d'au moins 20 ans.

PUBLIC UTILITIES ACT

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INDEPENDENT POWER PRODUCTION AND MICRO-GENERATION REGULATION

RÈGLEMENT PORTANT SUR LA PRODUCTION INDÉPENDANTE D'ÉNERGIE ET LA MICRO-PRODUCTION

O.I.C. 2019/026

DÉCRET 2019/026

Effective Date:

January 25, 2019

Date d'entrée en vigueur :

25 janvier 2019

O.I.C. 2019/026
PUBLIC UTILITIES ACT

INDEPENDENT POWER PRODUCTION AND MICRO-GENERATION REGULATION

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.

DÉCRET 2019/026
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

RÈGLEMENT PORTANT SUR LA PRODUCTION INDÉPENDANTE D'ÉNERGIE ET LA MICRO-PRODUCTION

La commissaire en conseil exécutif, conformément à la *Loi sur les entreprises de service public*, décrète :

1 Est établi le *Règlement portant sur la production indépendante d'énergie et la micro-production* paraissant en annexe.

Fait à Whitehorse, au Yukon, le 25 janvier 2019.

Commissioner of Yukon/Commissaire du Yukon

INDEPENDENT POWER PRODUCTION AND MICRO-GENERATION REGULATION

RÈGLEMENT PORTANT SUR LA PRODUCTION INDÉPENDANTE D'ÉNERGIE ET LA MICRO-PRODUCTION

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1 Interpretation

(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

RÈGLEMENT PORTANT SUR LA PRODUCTION INDÉPENDANTE D'ÉNERGIE ET LA MICRO-PRODUCTION

1 Interprétation

(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* 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 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* »

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;

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) 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).

(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).

2 Excluded undertaking — independent power production facility

(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

2 Entreprise exclue — installation de production indépendante d'énergie

(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) 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.

(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.

3 Excluded undertaking — micro-generation facility

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.

4 Connection of micro-generation facility to electrical system

(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.

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) 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.

3 Entreprise exclue — installation de micro-production

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.

4 Installation de micro-production reliée au système électrique

(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) 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;

(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

(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) 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) 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

(b) provide written notice to the owner of the facility that the application is approved.

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) aviser par écrit le propriétaire de l'installation que la demande est approuvée.

5 Connection of micro-generation facility to electrical system

(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.

5 Installation de micro-production reliée au système électrique

(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.

6 Change to nameplate capacity of micro-generation facility

(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.

6 Changement de la capacité nominale de l'installation de micro-production

(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) 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.

(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.

(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) 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.