IN THE MATTER OF YUKON ENERGY CORPORATION 2025-2027 GENERAL RATE APPLICATION TO THE YUKON UTILITIES BOARD

FINAL ARGUMENT

YUKON ENERGY CORPORATION

November 12, 2025

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PREFACE

OVERVIEW OF YUKON ENERGY APPLICATION

Yukon Energy Corporation (Yukon Energy or YEC) submitted its Application to the Board on May 12, 2025 (Exhibit 1-A) for adjustments to its revenue requirements, rates and other related matters as required to recover its forecast costs to supply customers in the 2025, 2026 and 2027 test years and to plan for future requirements thereafter.

The Application as filed in May 2025 seeks approval of forecast revenue requirements of $107.392 million for 2025, $122.406 million for 2026 and $134.850 million for 2027, with a required rate increase by 2027 of 33.73%, subject to adjustments required as a result of corrected and updated information provided subsequently in Yukon Energy's responses to Board requests for Supplementary Information (Exhibit 2), its responses to Information Requests (Exhibit 4), its letters of September 19, 2025 (Exhibit 5) and October 14, 2025 (Exhibit 3), its Opening Statement (Exhibit 8), its evidence provided during the oral hearing, and Yukon Energy's final undertaking responses filed October 28, 2025.

In the response Yukon Energy provided to Undertaking #13 (in accordance with the Board's direction at the hearing) on October 28, 2025, Yukon Energy provided updated forecast revenue requirements of $108.926 million for 2025, $125.733 million for 2026, and $135.962 million for 2027, with an updated required rate increase by 2027 of 34.58%, to reflect the impact of specified corrected and updated information.

Board Order 2025-12 approved an interim refundable rate adjustment rider increase of 17.89 percentage points (Rider J) effective July 1, 2025, and a further 19.66 percentage points effective January 1, 2026. The Application seeks the following (with changes reflecting the updated information provided in the response to Undertaking #13):

- Final rates for 2025 and 2026, and a true-up rider if required, effective April 1, 2026; and
- Final test year 2027 rates effective January 1, 2027, to coordinate the 19.62 percentage point Rider J rate increase with the removal of Yukon Energy's 2023/24 GRA true-up Rider J1 of 9.45% (which is effective until December 31, 2026, pursuant to Board Order 2024-13).

OUTLINE OF YUKON ENERGY'S FINAL ARGUMENT

Yukon Energy's Final Argument outlines the record before the Board, including key evidence that supports the requested Orders. It includes the following major sections:

- **Part 1 – Introduction:** Part 1 of the Final Argument restates the key factors driving Yukon Energy's 2025-2027 revenue requirement, addressing, at a high level, the core elements of the overall Application as submitted, updated and reviewed during the hearing process. This includes matters addressed in the Application (PDF pages 2 to 9) and Supporting Tab 1, information requests (IRs), the Opening Statement (Exhibit 8) and undertaking responses (including Exhibit 20 and YEC Responses to Undertakings filed October 28, 2025). Part 1 also summarizes the updates YEC has made to the Application and their impact on test year revenue requirements and rate increases, as well as Yukon Energy's ongoing approach to adaptation and management of its business and operations as reviewed in the current GRA proceeding.

- **Part 2 – Response to Key Issues Raised:** Part 2 of the Final Argument responds to key issues raised by the Board and intervenors in the IR process and the oral hearing, and provides transcript and undertaking references containing more detailed information on these issues. This includes three sections addressing the key issues relating to Tabs 2, 3 and 5 of the Application (Section 2.1: Tab 2 - Sales & Generation; Section 2.2: Tab 3 - Revenue Requirement; and Section 2.3: Tab 5 - Capital Projects), and a fourth section addressing other issues raised in the course of the proceeding (Section 2.4: Other Matters).

In the above noted sections of Part 2, Yukon Energy aims to address the main concerns about specific elements of the Application that appear to arise from the Board's interrogatories and/or from the cross-examination of Yukon Energy's panel by the Board and its counsel at the hearing, as well as concerns raised by intervenors to the extent that they are relevant to the matters properly in issue before the Board in this proceeding. Yukon Energy submits, however, that the commentary and supporting evidence it has already submitted in the proceeding, including its filed Application, its answers to the many interrogatories, and the other evidence it has submitted (including responses to undertakings) provide a complete answer to all such concerns, and fully support the reasonableness and necessity of the proposed revenue requirements. Further, no evidence-based contrary position has been tendered by any party.

Accordingly, Yukon Energy submits that the record now before the Board in this proceeding contains all of the evidence the Board may require to address the Orders requested.

PART 1: INTRODUCTION

1.1 FACTORS DRIVING THE 2025-2027 REVENUE REQUIREMENT INCREASE

The Application as filed in May 2025 forecast a cumulative required rate increase of 33.73% to recover forecast revenue shortfalls. With the updates noted in response to Undertaking #13, that cumulative required rate increase is now forecast at 34.58%.

Without the adjustments applied for in this GRA, the Application forecasts that Yukon Energy would have a negative return on equity (ROE) of increasing magnitude over the test years: -0.84% for 2025 (with a revenue shortfall of approximately $16.5 million); -5.24% for 2026 (with a revenue shortfall of approximately $29.7 million); and -7.08% for 2027 (with a revenue shortfall of approximately $40.2 million) (Exhibit 1-A, Tab 1, PDF page 26, lines 15-19). This means that Yukon Energy would not earn enough revenue to cover its annual business costs and make critical investments needed to replace aging infrastructure, meet Yukoners' growing demands for winter power, and operate and maintain a safe and reliable electricity system. It would also fail to satisfy the requirement in section 2 of the *Rate Policy Directive (1995)*, OIC 1995/90 (as amended), for the Board to set rates that are sufficient to enable Yukon Energy to recover a fair return (less 0.5%) on its equity used to finance its rate base.

As reviewed in the Application (Exhibit 1-A, Tab 1) and in the Opening Statement (Exhibit 8), the forecast revenue shortfalls and required rate increase reflect the urgent and significant investments needed in the Yukon Integrated System (YIS) electricity infrastructure to safeguard and strengthen existing aging generation, transmission and distribution facilities, while at the same time building new sources of electricity needed to meet unprecedented growth in forecast customer demand year after year.

Yukon Energy noted in Exhibit 8 that aging infrastructure and rapidly increasing demand are in no way unique to the Yukon. Electricity utilities across Canada face the same kinds of pressures and challenges. The impact of these challenges is particularly acute in the Yukon because of the isolated nature of the Yukon grid, which requires Yukon to be entirely self-sufficient to provide a sufficient supply of dependable electrical power on cold winter days and into the future.

In this context, the Application (Exhibit 1-A, PDF pages 32-33) indicates that approximately 64% of the $44 million forecast revenue requirement shortfall for 2027 is attributable to cost increases related to capital and deferred costs. Together, 17 major projects account for approximately $298.5 million or about 86% of the net rate base capital additions [net of 2023/24 GRA additions and contributions] before depreciation and amortization in the test years – subject to the updates noted in Exhibit 8, and summarized further in Section 1.2 below.

The balance of the 2027 revenue shortfall forecast in the Application (36% of 2027 shortfall costs) is accounted for by O&M labour cost increases (10%), non-labour O&M (11%, includes diesel rental costs), fuel price increases (9%), and other factors such as changes in energy and peak load as well as Independent Power Producer (IPP) power purchase costs (6%) (Exhibit 1-A, PDF page 33).

Key Drivers of 2025, 2026 and 2027 Rate Increases

The Application (Exhibit 1-A, Sections 1.1 to 1.4, PDF pages 18-26) explains the context for the current GRA. This includes a review of current challenges being faced by Yukon Energy including rapid growth in winter demands for power; aging infrastructure; fluctuating industrial loads; complex and costly regulatory process to renew operating permits and authorizations; the isolated nature of the Yukon's electricity system; a small customer base to recover costs from; and increased competition for government funding and grants. Sections 1.1.3 and 1.1.4 of the Application also specifically highlight Yukon Energy's approach to building a resilient, robust and renewable energy future, including Yukon Energy's short term action plan and its road map for the next 25 years.

Further information on these challenges, including system issues related to microgrid and IPP renewable energy sources (including adverse impacts on Yukon Energy spinning reserve requirements and costs), was reviewed in Yukon Energy's responses to IRs (Exhibit 4, YUB-YEC-1-1 through YUB-YEC-1-10) and in its panel's responses to cross-examination by Board counsel (transcript pages 40-65) and by Board members (transcript pages 416-419; see also Transcript errata filed October 29, 2025).

The Application (Exhibit 1-A, Section 1.2, PDF pages 32-36) and Opening Statement (Exhibit 8, pages 4-7) highlight the three underlying factors that drive the need for the unprecedented level of capital investment along with the non-fuel O&M costs that are described in this GRA: (i) sustaining capital requirements and strengthening the power system; (ii) increasing the supply of dependable winter capacity; and (iii) rising costs and project complexity.

It is worth reiterating Yukon Energy's summary of these three key factors from the Opening Statement:

(i) Sustaining Capital Requirements and Strengthening the Power System

- Many of the Yukon's hydro generation assets are aging and in need of significant investment to ensure continued safe and reliable service. Some facilities have been operating for decades and now require structural upgrades, maintenance, and relicensing. This includes critical work at the Mayo hydro facility, such as the spillway project, slope stabilization, and surge tank replacement. These are not discretionary projects; they are essential to maintaining existing renewable generation, avoiding catastrophic failures, and protecting nearby communities. Renewing aging hydro infrastructure is a cornerstone of Yukon Energy's Road Map to 2050 and fundamental to preserving the renewable energy foundation that Yukon already has in place.

- Yukon Energy is also investing in a series of projects that will strengthen the reliability and resilience of the power system and support future growth. This includes transmission line upgrades across the territory, and a voltage conversion in Dawson City. Upgrading decades-old power lines improves YEC's ability to deliver the power needed by communities across the Yukon safely and reliably, while reducing the risk of outages – particularly during periods of extreme weather or high demand.

- Together, 15 of the 17 major capital projects over $2 million proposed to be added to rate base in the Application relate to sustaining capital requirements and strengthening the power system.[1] Together, these projects account for approximately $236 million of net capital additions in the Application before depreciation and amortization, representing about 68% of all Application net rate base additions during the test years. The Tunnel project update (see updates below) reduces these net rate base additions.

(ii) Increasing the Supply of Dependable Winter Capacity

- The Yukon is growing, and so are its electricity needs. With population growth, more homes installing electric heating and more electric vehicles (EVs), YEC's winter peak demand is rising sharply. Under current conditions, on a typical winter day, homes and non-industrial businesses connected to the grid already use about 80% of what YEC can generate at any given moment. Between 2015 and 2020, peak demands for electricity from Yukon homes and non-industrial businesses increased by 25%. This upward trend shows no signs of slowing, with non-industrial peak demand projected to rise by about 40% by 2030 and 50% by 2035 when compared to 2020. Given the growing pressure on the system, ensuring a reliable electricity supply during the coldest days of the year is more critical than ever to protect public safety and support the wellbeing of Yukon communities.

- As electricity demand continues to rise, especially during Yukon's dark, cold winters, so does the need for firm, reliable capacity that can be counted on when Yukoners need it most. To meet this need, YEC is investing in new sources of dependable winter capacity that can respond instantly to peak loads, emergencies, and unplanned outages.

- This includes replacing aging diesel units in Faro and Whitehorse, adding new backup generation capacity in Dawson City as part of the Thermal Replacement Project, and building a new grid-scale battery energy storage system (BESS) and Power Centre in Whitehorse. These investments will increase the supply of dependable capacity when it's needed most during winter peaks and help ensure that the power system remains stable. This firm winter capacity plays a fundamental and vital role by acting as a safety net during periods when renewable generation is unavailable or insufficient, and by enhancing energy security across the territory.

- Two major projects proposed to be added to rate base in the original Application as filed – the Thermal Replacement and BESS project[2] – relate to this cost driver. Together, they account for approximately $62.5 million of net capital additions in the Application before depreciation and amortization, representing about 18% of all Application net rate base additions during the test years.

- A third project – the new Whitehorse Power Centres Project – also exemplifies this cost driver. That project, including the South Power Centre that YEC now projects will be brought into service in the 2027 test year, will serve three main purposes:

    1. It will increase the size of the Yukon's electricity system and provide additional sources of dependable capacity that Yukoners can rely on during the winter to keep homes

[1] This includes all 15 projects listed in Tables 5.2-2, 5.2-3, 5.3-1 and 5.3-2 of the Application (PDF pp. 196 and 202).
[2] See Table 5.2-1 in the Application (PDF p. 195).

warm and lights lit on the coldest of days, in drought years, and when intermittent renewable resources are not available.

2. It will reduce Yukon Energy's reliance on rental diesels. Renting diesel units each winter, while cost-effective over a short period of time, comes with risks such as limited supply chain, lower reliability, and reliance on an external contractor for maintenance. When all Whitehorse Power Centres are complete in 2035, the capacity installed at these new power centres will account for the capacity that rental diesels are currently providing each winter, plus additional capacity needed to address growing demands for power.

3. It will provide the substation and transmission infrastructure needed to support the increased power demand Yukon Energy is expecting in and around Whitehorse, and the potential for additional batteries to enhance grid stability and flexibility as more intermittent renewable resources are added to the grid.

(iii) Rising costs and project complexity

- Yukon Energy has a critical need for more resources to plan, manage, and deliver an increasing volume of work across all areas of its business. This includes supporting larger and more complex capital projects – both in scope and expenditure – and meeting growing expectations from regulators, stakeholders and rights holders for greater involvement and transparency in how we operate.

- This added complexity contributes to the forecast cost of many of the same major projects noted above that are aimed at addressing the first two underlying factors driving the costs of this GRA.

- Yukon Energy's work is also shaped by external financial pressures, including inflation, fuel price fluctuations, long-term debt servicing, diesel rental costs, and rising non-fuel operations and maintenance expenses. In this more complex operating environment, Yukon Energy needs additional staff capacity to oversee multi-stakeholder and multi-jurisdictional projects, manage increased maintenance and compliance requirements, and enhance environmental monitoring.

Overall, strong strategic planning and coordination with all levels of government will be required to support the Yukon's transition to a more renewable energy future while sustaining the facilities needed to reliably serve growing electricity load demands. As Yukon Energy moves forward, ongoing investments in infrastructure and winter capacity will be crucial to meeting immediate power needs and supporting renewable energy growth.

Yukon Energy's Opening Statement (Exhibit 8, page 8) provided the following concluding point regarding the key factors driving the current GRA revenue requirements – highlighting the critical importance of Yukon Energy's relationships with other parties, including government grant funding and other external investment sources, regulatory processes affecting Yukon Energy projects, and partnerships with other parties including local communities and First Nations:

> Delivering the projects outlined in our Application requires construction financing, efficient regulatory processes, and partnerships. The Yukon's electricity system is at a state where the investments needed are "must-haves", not "nice-to-haves". Deferring projects puts reliability and safety at risk. Reducing the impact of these investments on electricity rates will depend on Government grant funding and other sources of external investment.

1.2 CORRECTIONS AND UPDATES SINCE MAY 2025 APPLICATION FILING

During the course of Yukon Energy's responses to supplementary information requests from the Board (Exhibit 2) and IRs (Exhibits 4 and 5), and in subsequent Yukon Energy filings prior to the oral hearing (Exhibits 3 and 8), Yukon Energy provided the Board with various corrections and updates to information in the Application.

Consistent with the explanation Mr. Epp provided during the oral hearing (transcript page 168, line 21 to page 171, line 1), Yukon Energy has sought to provide the Board with access to the most up-to-date information available as of the date of the hearing to enable the Board to reflect both resulting increases and decreases in projected costs in the final test year's revenue requirement.

In particular, in its response to Undertaking #13 filed October 28, 2025, Yukon Energy has provided updated forecast revenue requirements of $108.926 million for 2025, $125.733 million for 2026, and $135.962 million for 2027, with an updated required rate increase by 2027 of 34.58%, to reflect the impact of specified corrections and updated information that were already on the record of the proceeding.

Undertaking #13 included the following corrected and updated information:

- The following corrections as summarized in Yukon Energy's September 19, 2025 letter (Exhibit 5):
  - In response to UCG-YEC-1-8 (a) and (c), Yukon Energy noted that the capitalization in Schedule 4 in Tab 7 for 2025 did not use the deemed 60/40 debt to equity ratio, and that the resulting correction results in about a $0.08 million reduction in the revenue requirement for the 2025 test year.
  - In response to YUB-YEC-1-50 (b), Yukon Energy provided detailed calculations of the amortization expenses for the Whitehorse and Mayo relicensing projects, as well as impacts on the amortization expenses included in the GRA. These corrections, as noted in the IR response, increase the amortization expenses for the 2025 ($0.637 million), 2026 ($1.273 million) and 2027 ($1.273 million) test years – and also result in offsetting reductions in return on rate base due to reductions in the net rate base net of amortization. The overall impact of this correction is a $0.620 million increase in the revenue requirement for 2025, a $1.200 million increase for 2026, and a $1.118 million increase for 2027.
- The following updates, as summarized in the Exhibit 5 cover letter (page 2):

- Labour cost increases per YUB-YEC-1-37 (c) of $0.899 in 2025 and $0.646 million in 2026, reflecting:

  - higher than normal forecast costs of $0.650 million to June 30, 2025 due to significant added overtime to run and maintain diesel engines (low water levels and a low snowfall in winter 2024/25 caused diesel generation to greatly exceed planned generation, a trend expected to continue in 2026 and potentially 2027); and

  - lower than the forecast vacancy factor to June 30, 2025 as shown in YUB-YEC-1-38 (b) and (c), resulting in $0.250 million higher forecast labour expense in 2025.

- Non-labour O&M thermal consumables cost increases per YUB-YEC-1-37 (d) of $0.656 million in each of 2025 and 2026, reflecting the significant added diesel maintenance expenses that are now forecast due to higher-than forecast diesel generation related to low water levels and a low snowfall in winter 2024/25.

- Non-labour O&M diesel rental cost increases per YUB-YEC-1-37 (d) of $0.174 million in 2025, $0.674 million in 2026 and $0.767 million in 2027, reflecting final contract escalation at 4% per year instead of the 2% per year escalation that was assumed in the Application.

- Insurance cost reductions per YUB-YEC-1-47 (d) of $0.282 million in 2025, $0.319 million in 2026 and $0.326 million in 2027, reflecting the $5 million dollar deductible in the final contract, which is much higher that the $1 million deductible originally assumed in the Application. (The update does not reflect potentially higher Yukon Energy costs related to the higher deductible.)

- Brushing cost changes per YUB-YEC-1-64 (a), with a decrease of $0.461 million in 2025 and an increase equal to the same $0.461 million in 2026, reflecting revised brushing plans as explained in this IR response.

- As summarized in the Exhibit 5 cover letter (page 2), the update provided in YUB-YEC-1-8 (a) and (b) Attachment 1 added the Whitehorse Power Centres project phase 1 (South Power Centre 15 MW) to the 2027 test year rate base, with $0.711 million added depreciation and a $28.4 million addition to mid-year net rate base. The total impact of this addition on the 2027 revenue requirement is $2.201 million ($2.415 million added depreciation and return on rate base, less $0.214 million reduction of four forecast diesel rental units as explained in the above IR response and with the revised diesel rental cost assessment provided in Exhibit 8, page 3).

  - The Whitehorse Power Centres update addresses Yukon Energy's forecast increases in non-industrial peak winter demand on the YIS by 1.3 MW for winter 2025/26, 4.4 MW for winter 2026/27, and 6.7 MW for winter 2027/28, as provided in YUB-YEC-1-30 (b). Without the addition of the South Power Centre in 2027, this update would result in updated dependable capacity shortfalls of 1.9 MW in 2026/27 and 8.1 MW in 2027/28 (as shown in the table in Exhibit 4, PDF page 184), assuming the Application's forecast use of 22 rented diesel units both winter. This increase in forecast demand is predominantly related to the electrification of heating, improvements in building energy and envelope efficiency, and electric vehicle update, as well as changes in the design temperature from -39ºC to -40ºC, which is the coldest average temperature in the last ten years.

    - Without the Whitehorse Power Centres Project's planned addition of dependable capacity for winter 2026/27, Yukon Energy would require five additional rental diesel units to close the dependable capacity shortfall for winter 2027/28 (i.e. an increase from 22 to 27 rental units). Instead, as shown in the table in Exhibit 4, PDF page 137, the addition of the South Power Centre during the 2027 test year will allow for the removal of four rental diesel units that winter (i.e. a reduction from 22 to 18 rental units).

- As provided in Exhibit 3 and reviewed in Exhibit 8, the update for a delay in schedule for in-service of the Wareham Dam Spillway – Tunnel (the Tunnel Project) to spring 2028. As a result of this expected delay, the Tunnel Project is no longer included in the updated 2027 test year revenue requirement, reducing 2027 revenue requirement costs by $2.7 million (removal in 2027 of $0.513 million depreciation and $36.9 million mid-year rate base with its related return on rate base).

1.3 ONGOING YUKON ENERGY ADAPTATION AND MANAGEMENT

The Board's review and scrutiny of the current GRA – through its IRs, the cross-examination of Yukon Energy's panel by the Board and its legal counsel, and the Board's undertaking requests to Yukon Energy – have served to highlight key realities faced by electrical utilities across Canada, including but not limited to: demands for power outpacing supply; the volume of investments urgently needed for capital projects that are larger and more complex than existing staffing levels can support on their own; and higher frequency of natural disasters like forest fires and floods that require immediate attention and result in planned work being deferred.

The Application updates reviewed above further illustrate the degree to which Yukon Energy needs to be able to address and adapt its business and operations on a constant basis – often within relatively short time periods – to address ongoing changes affecting dependable capacity shortfalls, major sustainable resource projects, aging infrastructure, relicensing regulatory realities, water supply and weather and climatic conditions, and other unexpected events and circumstances.

Unexpected things happen. This is a practical reality that electrical utilities face. When they do, as an essential service provider, Yukon Energy needs to be able to respond.

In its various IRs and in cross-examination of Yukon Energy's panel – particularly with respect to such topics as specific capital project costs and labour cost changes from prior forecasts – the Board has focused attention on changes since the last GRA. That focus further highlights the degree to which Yukon Energy must be able to deal with ongoing adaptability needs.

For example, looking at major capital projects costing >$2 million, the evidence in this proceeding has shown ongoing changes to forecast schedules and budgeted costs. However, the evidence has also provided greater clarity about the prudent management approaches that Yukon Energy has established for its major capital projects, including its utilization of staged and established cost classifications[3] as projects progress, as well as contingencies with risk registries,[4] stagegate schedules,[5] and, in several instances, differentiated roles and responsibilities for the project manager and owner's engineer.[6] What should be very clear from this evidence is that the large increase in Yukon Energy's forecast capital spending does not reflect problems with capital project management or budgeting practices. Rather, it reflects the unavoidable reality of Yukon Energy's need to adapt in a timely way to changes in requirements, regulatory processes, supply chain, costs, labour, and other external factors that cannot always be predicted with certainty, but which Yukon Energy has to meet.

Similarly, looking at Yukon Energy labour costs, the evidence in this proceeding has highlighted that Yukon Energy's actual overtime costs and use of consultants may often exceed forecasts. However, the evidence has also explained how Yukon Energy's ongoing overtime needs and its continued use of consultants have been driven by workload growth and the need to adapt to and effectively manage change.[7] Yukon Energy is a small utility with big utility generation and transmission project responsibilities that have been expanding faster than its staff complement.

Consistent with the prospective ratemaking principle, each GRA addresses forecast revenue requirements based on the best available forecasts and information for the applicable test years – and subsequent post-GRA events produce cost changes that affect shareholder returns rather than customer rates until the Board has the opportunity to address them in Yukon Energy's next GRA. Throughout, it remains Yukon Energy's ongoing responsibility to adapt to change in a nimble way to ensure its ability to continue satisfy its duty to provide reliable electricity for YIS customers.

[3] See responses to Undertaking #34 and Undertaking #35 in October 28, 2025 filing, and responses by Mr. Murchison during cross-examination by Board counsel on the use of these cost classifications at different stages of a project's development (transcript page 369, line 2 to page 375, line 7 and page 378, line 1 to page 362, line 3). At transcript page 362, lines 9 to 24 Mr. Epp also reviews 2021 GRA evidence on a close alignment of actual major project costs and forecasted costs from 2008 to 2021.
[4] See response to Undertaking #36 in October 28, 2025 filing.
[5] Mr. Murchison cross-examination by Board counsel, transcript page 392, line 28 to page 394, line 11.
[6] Mr. Murchison cross-examination by Board counsel, transcript page 396, line 14 to page 402, line 10.
[7] See Mr. Milner, Mr. Murchison and Mr. Epp responding to cross-examination by Board counsel, transcript page 128, line 4 to page 154, line 5.

PART 2: RESPONSE TO KEY ISSUES RAISED

2.1 TAB 2 – SALES & GENERATION

Tab 2 of Exhibit 1-A reviews changes in Yukon Energy grid sales and generation for 2025, 2026 and 2027 compared to 2024 grid sales and generation forecasts approved by the Board for the 2023/24 GRA. Overall, no material issues were raised during the oral hearing with regard to sales and generation forecasts for the 2025, 2026 and 2027 test years.

2.1.1 Sales Forecast

The Application forecasts total firm retail and industrial sales of 475.8 GWh in 2025, 484.7 GWh in 2026 and 493.9 GWh in 2027 (compared to 2024 approved of 494.7 GWh). Secondary sales are forecast at 2.9 GWh for each test year (see Exhibit 1-A, Tab 2, Table 2.1). Details for the sales forecasts in the Application were summarized in Yukon Energy's responses to information requests YUB-YEC-1-21 (Wholesale sales to AEY); YUB-YEC-1-22 (Major Industrial Sales); YUB-YEC-1-23 (YEC Firm Retail Sales); YUB-YEC-1-24 (Secondary Sales), and were addressed further by Yukon Energy's panel at the oral hearing, as noted further below.

YUB-YEC-1-30 (a) (Exhibit 4, PDF page 183) notes that Yukon Energy worked with ATCO Electric Yukon (AEY) (representing 80% of sales for the test years) as well as with major industrial customers during the preparation of the load forecasts in the current Application.

2.1.1.1 Wholesale Sales Forecast

Wholesale sales to AEY are reviewed in the Application (Exhibit 1-A) in Tab 2, Section 2.2.1, page 2-4 (PDF page 42). The Application confirms that Yukon Energy aligned its wholesale sales forecasts for the 2025-27 test years with AEY's forecast wholesale power purchases as directed by Board Order 2022-03.[8] It also includes details on discussions with AEY, and Yukon Energy's review and confirmation of the reasonableness of AEY's forecasts for use in the GRA (see Exhibit 1-A, page 2-4 (PDF page 42) and Exhibit 4, YUB-YEC-1-21 (PDF page 162)).

Discussion at the oral hearing on issues affecting wholesales focused on the following key topics raised by Board Counsel:

1. **Confirming AEYs 2024 forecast for connection of seven new large general service customers**[9] – Yukon Energy's response to Undertaking #5 in Exhibit 20 notes that "approximately 90% of the forecast load for those seven customers came online by end of 2024. Two customers out of seven never came online and/or service was cancelled."

[8] YUB Order 2022-03, Appendix A, paragraph 39.

[9] During the oral proceeding YEC was asked to provide an undertaking to "advise whether the seven large general service customers of AEY have been connected" (transcript page 69-70).

2. **Current capacity of micro generation on the integrated system and how much is exported to the system**[10] – As the microgeneration program is a Yukon government program, Yukon Energy does not have direct access to this data; however, Ms. Cunha reported at the hearing on publicly available information from the Yukon Bureau of Statistics, noting (transcript, page 46): "In 2023 there were 804 solar electric systems operating in the Yukon under the micro generation program with a peak generating capacity of 8.82 megawatts"; and "Although the actual total generation from these solar energy systems is unavailable, the systems added 3.667 megawatt hours of surplus energy to Yukon's electrical grid in 2023."

3. **The relevance of including Fish Lake Hydro forecast in the GRA, including references to OIC 1995/90**[11] **–** Yukon Energy's responses to Undertaking #8 (Exhibit 20, PDF p. 2) and YUB-YEC-1-87 (Exhibit 4, PDF p. 527) explain how the relevant provisions of the *Rate Policy Directive (1995)*, OIC 1995/90 (as amended) require renewable generation from all sources that are available to contribute to forecast customer requirements (as described in section 9(3)(a)) to be included in "long-term average annual renewal source availability" (LTA). This includes renewable generation from Fish Lake hydro, as well as renewable generation from other non-Yukon Energy owned sources.

   As explained further in the response to Undertaking #8, this is consistent with the rate stabilization purpose of section 9 of the *Rate Policy Directive*, which aims to smooth rate impacts of fluctuating levels of thermal generation (resulting from fluctuations in renewable generation), because generation from Fish Lake hydro and other non-YEC owned renewable generation sources reduces the amount of thermal generation required to meet customer requirements.

   The Board also asked YEC to comment further[12] on the relationship between YEC's use of Fish Lake hydro forecasts as part of its determination of the YEC hydro and thermal forecasts used in the GRA Application and YEC's understanding of AEY's net wholesale purchases (Undertaking #9). In response to that undertaking (Exhibit 20, PDF p. 3) and YUB-YEC-1-34 (Exhibit 4, PDF p. 192), Yukon Energy noted that AEY's firm power purchases from Yukon Energy are the result of the total AEY grid load, less AEY Fish Lake generation, less AEY grid standby diesel generation, and less micro generation, and that the power purchase forecasts provided by AEY for this GRA are already net of Fish Lake generation. Therefore, for purposes of calculating the revenue requirements for the 2025-2027 test years, Yukon Energy has continued to assume wholesale forecasts as provided by AEY net of Fish Lake LTA.

   Yukon Energy acknowledged further in its response to Undertaking #9 that it has not received confirmation from AEY that the Fish Lake Hydro sales assumed for their

[10] During the oral hearing in cross-examination (page 45) Yukon Energy was asked: "…what is the total current capacity of micro generators on the integrated system… and out of that total capacity, how much is exported to the integrated system that is exported after own use?"

[11] At pdf page 103 Board Counsel asked Undertaking #8: "to advise whether there is specific reference in OIC 2021/16 which is now incorporated in the 1995 Rate Policy Directive that requires Fish Lake hydro forecasts to be included in the GRA."

[12] Transcript page 104.

wholesale forecasts are based on LTA; however, there is no other available evidence that would alter that assumption (see also YUB-YEC-1-34 (b), Exhibit 4, PDF pp. 192-193).

In summary, the evidence that is before the Board supports approving the wholesales forecast for Yukon Energy as provided by AEY.

2.1.1.2 Major Industrial Customer Loads

Tab 2, Section 2.2.2 of the Application includes a summary of forecast information provided to Yukon Energy by Hecla Yukon and Victoria Gold (VG). Industrial sales for 2025, 2026 and 2027 are forecast at 42.8 GWh, reflecting a decrease of 3.3 GWh from 2024 preliminary actuals (see Exhibit 1-A, page 2-5 (PDF p. 43)). Actual sales for 2024 were at 23.3 GWh or 24.3 GWh lower compared to the 2023/24 GRA approved forecast load of 47.6 GWh.[13]

Details for the industrial load forecasts were further summarized as follows in IR responses:

- YUB-YEC-1-17 (b) (Exhibit 4, PDF pp. 156-157) notes that sales to Victoria Gold under receivership continue to be treated as industrial sales for billing purposes, which assumes ongoing mine operation. That IR response also reviews the basis for this (current sales are above the 1 MW threshold for industrial customers per Rate Schedule 39), as well as uncertainties regarding whether the mine will reopen, and implications for the RS 39 Fixed Charge if the mine is no longer considered an industrial customer. Yukon Energy will reassess this classification as new information becomes available.[14] Actual sales to Victoria Gold are reviewed in the response to YUB-YEC-1-22 (a-b) (Exhibit 4, PDF p. 163).[15]

- YUB-YEC-1-17 (a) and (d) (Exhibit 4, PDF pp. 155-157) notes that sales to Minto under care and maintenance were included in the general service class in the 2023/24 GRA forecasts, and that those sales to Minto under care and maintenance will continue during the current GRA test years. Any potential sales to Minto as an industrial customer, or any changes due to the sale of the mine to Selkirk First Nation, are unknown at this time.

    - Yukon Energy's response to Undertakings #2 and #3 in Exhibit 20 (PDF p. 1) also provided updated details of 2025 actual sales to Minto up to September 2025, at 3.5 GWh compared to 4.1 GWh for the same period assumed in the Application. Assuming the same average monthly sales to Minto for Q4 of 2025 and for the 2026 and 2027 test years, Yukon Energy provided an updated forecast of total annual sales to Minto of 4.7 GWh for each test year (i.e., 0.8 GWh/year lower than the sales originally forecast in the Application).

- YUB-YEC-1-23 (a) (Exhibit 4, PDF p. 166) notes that based on the information provided by Hecla Yukon, its near-term loads were expected to remain within the 2024 approved level; accordingly, the forecast for each of the 2025, 2026 and 2027 test years is 21.8 GWh.

[13] YUB-YEC-1-17 (c) (Exhibit 4, PDF p. 157).
[14] YUB-YEC-1-22 (c) (Exhibit 4, PDF p. 163). Yukon Energy does not have any new, reliable information at this time that would affect forecasts for 2026 and 2027.
[15] The actual sales to VG for the first six months of 2025 were about 6.0 GWh compared to the forecast sales of 10.4 GWh for the same period.

No material issues regarding the industrial sales forecast were raised in interrogatories or in cross-examination at the oral hearing regarding industrial sales forecasts. Yukon Energy's forecasts are reasonable and should be accepted.

2.1.1.3 Other Sales [Yukon Energy Retail and Secondary]

Retail and secondary sales forecasts are reviewed in Tab 2, Sections 2.2.3 and 2.2.4. Yukon Energy firm retail sales are comprised only of sales to residential, general service, streetlight and space light customer classes served directly by Yukon Energy in Dawson City, Mayo, Faro, and 12 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 firm sales are forecast at 59.3 GWh for 2025, 59.9 GWh for 2026 and 60.6 GWh for 2027, compared with 2023 actual sales of 57.0 GWh and 2024 preliminary actual sales of 58.7 GWh (Exhibit 1-A, PDF p. 44).

The basis for the residential,[16] general service,[17] lighting[18] and secondary sales[19] forecasts is provided in the Application (Exhibit 1-A, PDF pp. 44-46), and in Yukon Energy's responses to YUB-YEC-1-23 (Exhibit 4, PDF pp. 164-168) and YUB-YEC-1-19 (Exhibit 4, PDF pp. 159).

No material issues or concerns were raised in IRs or at the oral hearing regarding the residential, general service, lighting sales or secondary sales forecasts included in the 2025-2027 GRA sales and generation forecasts. As such, Yukon Energy's retail and secondary sales forecasts are reasonable and should be accepted.

2.1.2 Peak Demand Forecast & Dependable Capacity Requirement

The basis for the peak demand forecast is reviewed in detail in the Application at Section 2.4. Peak demand for the integrated system was forecast in the original Application at 127.4 MW in 2025, 132.2 MW in 2026 and 136.2 MW in 2027 (see Table 2.2, Exhibit 1-A, PDF p. 56). The econometric model used to determine peak forecasts for non-industrial customers for the Application is reviewed at page 2-12 of the Application (Exhibit 1-A, PDF p. 50), with further detail provided in YUB-YEC-1-30 (Exhibit 4, PDF pp. 183-185). Excluding industrial load, the forecast peak load in the Application for the purpose of determining the N-1 dependable capacity requirement is 120.6 MW

[16] See, in particular, Application, Tab 2, page 2-6 (Exhibit 1-A, PDF p. 44). Residential sales growth over the test period is consistent with Yukon government population growth projections (Yukon Bureau of Statistics growth projection for 2025-27 at around 2%). Ms. Cunha also responded to Undertaking #6 (page 81, line 9 to page 82, line 7 of the transcript), indicating Yukon Bureau of Statistics total Yukon population projections at 2% for 2025, and 1.9% for 2026 and for 2027; Whitehorse area population projection at 2.1% for 2025, 2.2 % for 2026 and 2% for 2027; and population projection for Dawson city, served by YEC, at 2% in 2025 and 2026 and 2.4% in 2027. See also YUB-YEC-1-23 (a) and (b) (Exhibit 4, PDF pp. 165-166). The residential sales forecast is reasonable considering historical growth in residential sales.

[17] See, in particular, YUB-YEC-1-23 (c) (Exhibit 4, PDF pp. 167-168). Sales to the Faro Mine remediation project and to Minto Mine care and maintenance load account for more than 37% of the firm General Service forecast retail sales in the test years. A growth rate of 1% was applied to general service sales excluding Minto and Faro remediation project related loads. A separate forecast was prepared for those two larger general service customers and then the forecasts were combined to get the total general service sales forecast.

[18] See, in particular, YUB-YEC-1-23 (b) and (d-f) (Exhibit 4, PDF pp. 165, 168). Lighting-related sales are not significant, and the forecasts for 2025, 2026 and 2027 are based on the 2024 results.

[19] See, in particular, YUB-YEC-1-19 (Exhibit 4, PDF p. 159). Due to uncertainties regarding the availability of secondary sales, Yukon Energy forecast secondary sales at the 2023/24 GRA approved level. This is the average of actual secondary sales in 2023 (at 2.2 GWh) and in 2024 (at 3.7 GWh). The actual secondary sales for the first six months of 2025 were at 0.033 GWh compared to the forecast of 0.7 GWh.

in 2025 (based on winter 2025/26), 125.4 MW in 2026 (based on winter 2026/27) and 129.4 MW in 2027 (based on winter 2027/28) (Exhibit 1-A, PDF p. 54).

YUB-YEC-1-30 (b) (Exhibit 4, PDF pp. 183-185) provides an update to the forecast peak load outlined in the Application, noting the following increases in forecast non-industrial peak for the purpose of determining the N-1 dependable capacity requirement compared to the May 2025 Application:[20] 121.9 MW in winter 2025/26 (1.3 MW increase from Application); 129.8 MW in winter 2026/27 (4.4 MW increase from Application); and 136.1 MW in winter 2027/28 (6.7 MW increase from Application). This IR response also provides further details regarding the updated N-1 dependable capacity requirements and the updated capacity shortfall and related diesel rental requirements for each test year (prior to consideration of the further updates related to the Whitehorse Power Centres Project noted in the response to YUB-YEC-1-8).

YUB-YEC-1-8, including Attachment 1 (Exhibit 4, PDF pp. 126-137) updates Yukon Energy's plans to address capacity shortfalls and reduce reliance on diesel. This includes an outline of Yukon Energy's plans to advance the initial stages of the Whitehorse Power Centres Project, with a planned in service for the South Power Centre Build (Phase 1) before the end of 2027 to meet the 2027/28 winter peak requirements, and a summary of resulting impacts on forecast diesel rental requirements. The information provided in YUB-YEC-1-8 Attachment 1 shows the Whitehorse Power Centres Project providing a 14.4 MW increase in dependable capacity for 2027/28 winter (15 MW with 96% ELCC) and a 6.2 MW reduction in required diesel rental capacity (4 x 1.53 MW per rental unit with 85% ELCC).[21]

Yukon Energy also provided the following additional details regarding the test year peak demand forecasts in its IR responses:

- YUB-YEC-1-31 (Exhibit 4, pp. 186-187) provides an overview of the capacity planning criteria used by Yukon Energy for system planning since 2006 (this is also reviewed in the Application at page 2-13 (Exhibit 1-A, PDF p. 51)), and confirms that to date, including this 2025-2027 GRA, the N-1 criterion, which focuses on non-industrial peak for capacity shortfall requirements, has been used for identifying the need for diesel rentals or other resources of firm dependable capacity.

- YUB-YEC-1-7 (Exhibit 4, PDF pp. 124-125) and YUB-YEC-1-32 (Exhibit 4, PDF p. 188) provide further details regarding effective load carrying capacity (ELCC), diesel rentals, and Forced Outage Rates (FOR) (elaborating on the evidence in the Application pages 2-14 and 2-15 (Exhibit 1-A, PDF pp. 52-53) explaining why FOR rates are applied; providing the basis for the FOR for AEY diesel units in communities connected to the YIS;[22] and

[20] The response notes: "Given the recent higher growth seen in population and electricity sales, the econometric model was updated by Itron in July 2025, after the current GRA was filed." It further notes the following key changes driving the increase in forecast non-industrial peak demand in the test years: "The key changes were predominantly related to the electrification of heating, improvements in building energy and envelope efficiency, electric vehicle uptake as well as a change in the design temperature from -39 degrees C to -40 degrees C, which is the coldest average temperature in the last 10 years."

[21] See also Yukon Energy's explanation of its application of effective load carrying capacity (ELCC) when calculating the dependable capacity of its generation assets for the purposes of this GRA: Application, Section 2.4 (Exhibit 1-A, PDF pp. 52-53); YUB-YEC-1-7 (Exhibit 4, PDF pp. 124-125); YUB-YEC-1-32 (a) (Exhibit 4, PDF p. 188).

[22] The response to YUB-YEC-1-32 (a) (Exhibit 4, PDF p. 188) notes that an industry-standard ELCC of 90% is assumed based on the 5-year weighted forced outage rate of about 10% for conventional generation (gas, diesel, oil, or coal) published by North American Electric Reliability Corporation (NERC).

clarifying that Yukon Energy's requirement to use rental diesel units is also determined by factors not involving the FOR impacts (as outlined in the response to YUB-YEC-1-8).

The updated peak demand forecast for the test years as required for dependable capacity determinations, and the forecast dependable capacity as updated above, are reasonable and should be accepted.

2.1.3 Generation Forecast

The Application's forecast firm generation of 517.7 GWh for 2025, 527.4 GWh for 2026, and 537.3 GWh for 2027 is based on forecast firm sales plus system losses of 8.8%.[23] No material issues were raised regarding the firm sales forecasts or system losses forecast, and consequently the forecast generation for 2025, 2026 and 2027 is reasonable and should be accepted. Details for the generation forecasts in the Application were summarized in the responses to information requests and in discussion at the oral hearing.

The LTA thermal generation forecast for the test years is consistent with OIC 2021/16 directives (section 9(2) and (3) of *Rate Policy Directive (1995)*, as amended) which require that the forecast thermal generation to be included in rates must be determined based on long-term average (LTA) annual renewable source availability. Apart from Board counsel's questions about the inclusion of Fish Lake hydro generation in LTA (as addressed above), no material issues regarding test year thermal generation forecast were raised at the oral hearing, IRs or other submissions. Yukon Energy provided further clarification of its thermal generation forecasts in its responses to YUB-YEC-1-33 (b-c) (Exhibit 4, PDF pp. 189-190),[24] YUB-YEC-1-27 (Exhibit 4, PDF p. 179),[25] and YUB-YEC-1-34 (a-b) (Exhibit 4, PDF pp. 191-193)[26] and YUB-YEC-1-34 (d) (Exhibit 4, PDF p. 193).[27] Yukon Energy also confirmed in its response to Undertaking #7 (Exhibit 20, PDF p. 1) that there are no specific provisions in the LWRF Term Sheet for excluding water years that would increase the LTA for thermal generation, but noted that the LWRF Term Sheet references section 9(1) of OIC 2021/16 which specifies that LTA annual renewable source availability is "determined using <u>available</u> historical water years records respecting long-term hydro generation" [emphasis added] as well as "available information respecting other renewable generation".

IPP generation is beyond the control of Yukon Energy, and the updated forecasts should be considered reasonable and accepted for test year generation forecasts. The response to YUB-YEC-1-34 (c) (Exhibit 4, PDF p. 193) clarifies that IPPs referenced in the LTA thermal generation

[23] See Table 2.2 (Exhibit 1-A, PDF p. 56). Application, page 2-8 (Exhibit 1-A, PDF p. 46) notes that the 8.8% line loss forecast is the same as the approved losses in the 2023/24 GRA and the average for the 2022-2024 actuals [2022 at 9.0%, 2023 and 2024 at 8.7%]; actual losses were 8.7% in 2023 and preliminary actual losses in 2024 were also 8.7%.

[24] Provides clarification regarding the load years used in the YECSIM model for determining LTA generation.

[25] Explains why the number of water year records has not changed since the last GRA, and notes that there was insufficient time and available resources for Yukon Energy staff to update the water years to include 2022-2024 water records to be used in the modelling. Considering the low water conditions experienced in 2023/24 and 2024/25, the potential impact of including 2022-2024 water years would be to increase the long-term average thermal generation.

[26] Clarifies that YEC does not have specific Fish Lake Hydro generation forecasts for its GRA submission, as the AEY wholesale forecasts provided for YEC adoption already had removed the impacts of AEY's assumed Fish Lake Hydro generation, and provides additional detail regarding how this is addressed as part of the wholesales forecast and for determining LTA for the GRA application. See also Yukon Energy's response to Undertaking #9 in Exhibit 20 (PDF p. 3).

[27] Explains that using one table for all three years is a reasonable approach for calculating the LTA thermal generation requirements for various potential YEC generation loads.

calculations pertain only to IPPs with which Yukon Energy has an EPA and that are forecast to be connected to the YIS during the GRA test years.

First IPP deliveries were in November 2021.[28] Tab 2, Table 2.2 (Exhibit 1-A, PDF p. 56) and YUB-YEC-1-20 (c) (Exhibit 4, PDF p. 161) note that IPP deliveries for 2025, 2026 and 2027 are forecast at 17.717 GWh/year; and reflect contract volumes based on EPAs signed with IPPs; IPP generation forecasts in the Application assume the seven currently connected IPPs. The volume remains the same for each test year as no other IPPs are expected to be connected to the grid over this period. The reduction in percentage share of IPPs out of total load from 3.4% in 2026 to 3.3% in 2027 reflects the forecast increase in overall load.

The response to YUB-YEC-1-26 (a) (Exhibit 4, PDF p. 176) clarifies that the lower actual IPP deliveries in 2024 were due to later than expected commercial operation dates (COD).[29]

In summary, the LTA thermal generation forecasts should be considered reasonable and accepted for test year generation forecasts.

2.2 TAB 3 – REVENUE REQUIREMENT

Tab 3 of the Application (Exhibit 1-A) reviews Yukon Energy's revenue requirement for the test years. This includes an overview followed by more detailed consideration of the following key revenue requirement components: fuel and purchased power (Tab 3, Section 3.2); non-fuel operating and maintenance expenses (Tab 3, Section 3.3); rate base, depreciation and amortization (Tab 3, Section 3.4); and return on rate base (interest and ROE) (Tab 3, Section 3.5). Stabilization mechanisms are summarized in Tab 3, Section 3.6.

Responses to key issues raised are addressed below for each of these components. Details on capital costs that impact rate base are addressed separately in Section 2.3 below.

2.2.1 Fuel and Purchased Power

Fuel and purchased power costs forecast for the 2027 test year are $6.077 million higher than 2024 approved costs (see Application, Table 3.1, Exhibit 1-A, PDF p. 63). The total increase by the end of the 2027 test year reflects higher fuel prices, as well as increased purchased power cost for IPPs.[30] The manner in which forecast fuel prices for the Application were determined was reviewed in Section 3.2 of the Application. Yukon Energy also provided additional information and clarifications in response to the following information requests: YUB-YEC-1-35, re: Fuel and Purchased Power (Exhibit 4, PDF pp. 194-197); YUB-YEC-1-36, re: LNG supply (Exhibit 4, PDF p. 198); and YUB-YEC-1-20, re: IPP renewal generation (Exhibit 4, PDF pp. 160-161).

[28] YUB-YEC-1-20 (a) (Exhibit 4, PDF p. 160).

[29] The response notes that the 2023/24 GRA assumed Takhini Power Corp's (Arctic Pharm) 2 MW solar COD to be April 1, 2024, but the actual COD was July 19, 2024. Similarly, Sunergy's 2 MW solar COD was assumed to be March 1, 2024, but the actual COD was May 29, 2024. The COD for two wind IPPs were also eight days later than expected, with lower deliveries for the first month. The IPP deliveries are also subject to weather conditions that impact the energy source of the IPPs.

[30] Application, page 3-2 (Exhibit 1-A, PDF p. 63).

Forecast fuel costs include: (1) forecast thermal generation fuel costs for the forecast long-term average (LTA) thermal generation (as determined in Tab 2) at forecast fuel prices; and (2) forecast maintenance fuel costs for LNG and diesel units in each test year: See Application, pages 3-3 to 3-6, and Table 3.2.1 (Exhibit 1-A, PDF pp. 64-67).

- Forecast long-term average thermal generation in the Application is 63.9 GWh in 2025, 70.9 GW in 2026 and 78.4 GWh in 2027, as compared with 75.3 GWh in 2024 approved. The fuel cost for forecast long-term average thermal generation is $16.791 million in 2025, $18.650 million in 2026 and $20.616 million in 2027 before considering forecast fuel costs for thermal maintenance activities (see Section 2.3.3 and Table 3.2.1, Exhibit 1-A, PDF pp. 48-49, 65).
- For maintenance activities, the forecast total diesel and LNG unit operation required is 0.038 GWh/year for each test year, amounting to $0.011 million per year (Exhibit 1-A, PDF p. 65).

Contract Prices for Fossil Fuels, IPPs

Proposed GRA fuel prices for approval by the Board reflect the following (see Application, pages 3-3 to 3-6 (Exhibit 1-A, PDF pp. 64-67) and YUB-YEC-1-36 re: LNG supply (Exhibit 4, PDF p. 198):

- This forecast for LNG cost reflects contracted liquefaction and shipping costs for 2025, as well as the most recent market price for commodity value prior to completion of the Application [i.e., the actual price for December 22, 2024]. Yukon Energy forecasts average efficiency for LNG generation of 2.55 kW.h/litre, which is the average efficiency for the last three years (Exhibit 1-A, PDF pp. 65-66).

- Forecast diesel prices for the test years reflect prices as of December 1, 2024, the most recent prices prior to completion of the Application. Diesel fuel efficiency is based on 2023/24 GRA approved efficiencies (Exhibit 1-A, PDF pp. 66-67).

Purchased power costs in the Application include forecast IPP purchases (see Tab 2, Table 2.2 (Exhibit 1-A, PDF p. 56) and YUB-YEC-1-20 (c) (Exhibit 4, PDF p. 161) of 17.717 GWh in each test year under the Yukon government's IPP Policy and OIC 2019/25.

The forecast fuel and purchased power costs for 2025, 2026 and 2027 test years are reasonable and should be accepted.

Thermal Fuel Mix

The Application assumes a forecast LTA thermal fuel mix of 80% LNG generation and 20% diesel generation (see Application, page 3-3, Exhibit 1-A, PDF p. 64).

Board Order 2024-05[31] 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." Tab 3, Appendix 3.3 (Exhibit 1-A, PDF pp. 145-148) addresses this directive and provides the justification for the adjusted fuel mix ratio. Further details are provided in the response to YUB-YEC-1-28 (Exhibit 4,

[31] Appendix A, paragraph 89.

PDF pp. 180-181) and YUB-YEC-1-63 (a) (Exhibit 4, PDF p. 344), which confirmed that there is no impact to Rider F from the proposed fuel mix.

- Appendix 3.3, Table 3.3-1 (Exhibit 1-A, PDF p. 146) provides the historical fuel mix (2016-2024) and the updated blended thermal ratio. This shows an average of 70% LNG and 30% diesel over that period. The average reflects the YIS load and water availability conditions noted in Table 3.3-1 for the nine-year period. It does not reflect any assessment of LTA fuel mix based on GRA forecast loads and available LTA water availability over the 41 water years of current information.

- The revenue requirements in the Application assume 80% LNG and 20% diesel. Appendix 3.3, Table 3.3-2 (Exhibit 1-A, PDF p. 148) provides the impact of the 80% LNG/20% diesel LTA mix proposed by Yukon Energy [which results in a $0.471 million increase in fuel costs compared to using the 90% LNG/10% diesel mix used in prior GRAs].

- The blended fuel mix required to be used for GRA purposes should reflect, to the extent practicable, information on LTA water availability as well as the forecast load requirements. Using the nine-year historical average fuel mix of 70% LNG/30%diesel would not reflect the available evidence on below LTA water availability, including prolonged periods of drought conditions (with related increases in LNG generation in the fuel mix).[32]

- Yukon Energy is not forecasting any unique events during the GRA test period that would affect the availability of LNG or diesel units and that would significantly impact the LTA fuel mix. Although unplanned issues might occur during the GRA test period that could impact the availability of these units, they do not impact the revenue requirements in this Application.

No material issues were raised during the hearing regarding the proposed thermal fuel mix, and consequently the proposed thermal fuel mix for the test years is reasonable and should be accepted.

2.2.2 Non-Fuel Operating and Maintenance Expense

Section 3.3 of the Application provides details on each component of the $9.435 million increase in forecast non-fuel operating and maintenance expense for the 2027 test year over the 2024 approved.[33] The increase in forecast labour expense accounts for approximately 47% of the 2027 vs. 2024 approved non-fuel O&M increase; the increase in non-labour production expense accounts for approximately 7%; and the increase in non-labour transmission and distribution expenses accounts for approximately 1% (see Application, Table 3.3, Exhibit 1-A, PDF p. 68). These are each reviewed further in Sections 2.2.2.1 to 2.2.2.3 below.

[32] Mr. Epp reviewed with Board counsel why the proposed fuel mix addresses the Board's direction to provide a correct LTA fuel mix, and why the nine-year average does not reflect the LTA over 41 years (transcript, page 89, line 17 to page 90, line 18). Mr. Epp also confirmed that the use of diesel rentals does not affect the LTA fuel mix (transcript, page 91, lines 10-25).
[33] This increase, broken out by labour and non-labour O&M expense, is also shown in Table 1-4 of the Application (Exhibit 1-A, PDF page 33).

There were no significant issues raised during interrogatories or the oral hearing with regard to general O&M,[34] administration,[35] insurance and RFID,[36] or property taxes[37], which together account for the balance of the increase. Yukon Energy provides some further comments on updated insurance costs, in Section 2.2.2.5 below; however, these other forecasts are not otherwise reviewed in detail in this argument. YEC will respond in reply argument to any specific issues or questions raised by intervenors regarding any of the forecasts.

2.2.2.1 Labour Expense

The total labour expense increase in 2027 from 2024 approved ($4.465 million) relates to additional headcount ($3.071 million, or 69% of increase) and labour rate increases (the remaining $1.393 million, or 31% of increase).[38] Test year forecast labour expenses are reasonable and required for YEC to address the full range of its responsibilities and challenges, and to reduce overtime costs. Each of these matters is explained in further detail below.

Yukon Energy typically uses Yukon government wage rate changes as guidance for negotiations with the Union for Yukon Energy employees. For the current Application, this information is not yet available.[39] As noted in YUB-YEC-1-37(a) (Exhibit 4, PDF p. 200), the Application applies a 3.0% labour rate escalation for 2025 and a 2.0% escalation for 2026 and 2027. This assumes an escalation rate for out-of-scope employees for 2025 that is equal to the rate set for in-scope employees under the 2023-2025 Collective Bargaining Agreement, and the escalation rate for 2026 and 2027 is estimated based on the assumed rate of inflation expected.

Yukon Energy's forecast labour costs included in the Application were based on the best information available at the time the Application was filed. Since that time, however, Yukon Energy has incurred additional labour expenses due to higher diesel generation requirements and a low vacancy factor. Labour costs for 2025 and 2026 are now forecast to be significantly greater than submitted in the Application. Specifically, YUB-YEC-1-37(c) (Exhibit 4, PDF pp. 201-202) notes updated increases in forecast labour costs of $0.899 million in 2025 over GRA forecast, and $0.646 million in 2026 over GRA forecast. These updated labour costs are included in the updated test year revenue requirements provided in Yukon Energy's response to Undertaking #13 filed on October 28, 2025.

FTE Complement Increase

Section 3.3.1 of the Application (Exhibit 1-A, PDF pp. 69-73) outlines a required cumulative 24.63 FTE increase in employee complement (2027 test year forecast compared to 2024 approved forecast). A complete and detailed justification for each of the added positions is provided in Appendix 3.2 (Exhibit 1-A, PDF pp. 117-144). Factors driving the increase in employee complement

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[34] SeeYUB-YEC-1-42 regarding clarifications provided regarding general O&M (Exhibit 4, PDF pp. 217-219).

[35] See YUB-YEC-1-43 and YUB-YEC-1-45 regarding clarifications provided regarding administration expense (Exhibit 4, PDF pp. 220-224, 227-235).

[36] See YUB-YEC-1-47 and YUB-YEC-1-48 regarding clarifications provided regarding RFID and insurance expense, including the update on reduction in insurance costs (Exhibit 4, PDF pp. 238-242).

[37] See YUB-YEC-1-49 regarding specific clarifications provided regarding property tax (Exhibit 4, PDF p. 243).

[38] Application, Section 3.3.1, pages 3-8 to 3-12 (Exhibit 1-A, PDF pp. 69-73).

[39] YUB-YEC-1-37 (b) (Exhibit 4, PDF pp. 200-201). Yukon Government is still in contract negotiations with its union for the calendar years of 2025, 2026 and 2027. Details of Yukon Government wage negotiations are not available to Yukon Energy.

were noted in Section 3.3.1 (Exhibit 1-A, PDF pp. 71-73) and further addressed in Appendix 3.2. Those factors include:

- 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.

The largest increase in employee complement is in Operations, reflecting Yukon Energy's updated strategic objectives that focus on safety and reliability. 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 and continuous improvement and to support future development projects.[40]

Yukon Energy has made a conscious effort to limit increases only to those areas where required. As Mr. Milner elaborated at the hearing, when Yukon Energy decides to add FTEs, its focus is on the need for long-term investment in areas requiring long-term support, as opposed to work of a shorter term nature (including unplanned maintenance or emergency-type work) that may be more efficiently outsourced to contractors (transcript page 191, line 7-14; page 192, lines 6-12). With that focus in mind, the forecast increase in Yukon Energy's employee complement is required to address the issues identified above, and to decrease overtime costs from what would otherwise be required (see further review below of "Overtime").

Vacancy Factor[41]

Tab 3, Section 3.3 and YUB-YEC-1-38 (Exhibit 4, PDF pp. 205-207) summarize vacancy factors. A vacancy factor of 9 FTEs was applied to labour expenses for each test year (the same vacancy factor that was used for the 2023/24 GRA).[42] The five-year average vacancy factor for 2020-2024 was 9.91 FTEs.[43] YUB-YEC-1-38 (c) (Exhibit 4, PDF p. 206) provides the actual monthly vacancy factor for the first six months of 2025 (noting an average vacancy factor of 5.01 FTEs), and YUB-YEC-1-37 (c) (Exhibit 4, PDF pp. 201-202) outlines how the lower-than-average vacancy factor is

[40] Application, page 3-11 (Exhibit 1-A, PDF p. 72).
[41] YUB-YEC-1-38 (Exhibit 4, PDF pp. 205-207) notes that vacancy factor is measured in terms of FTEs, while vacancy rate is a different calculation and is measured in percentage terms. Vacancy factor was used in the GRA Application and provides more comparable information than vacancy rate.
[42] Application, Page 3-8 (Exhibit 1-A, PDF p. 69). The response to YUB-YEC-1-38 (a) (Exhibit 4, PDF p. 206) notes that the actual 2024 employee complement was 123.71 FTEs, and vacancy factor was 7.99 FTEs.
[43] YUB-YEC-1-38 (b) (Exhibit 4, PDF p. 206).

impacting 2025 results (a higher forecast labour expense in 2025 by approximately $250,000, net of assumed lower overall overtime).

YUB-YEC-1-38 (d) (Exhibit 4, PDF p. 207) provides an update on incremental positions that have been filled in 2025 (noting seven of the eight positions filled, with the eighth in interview stage).

Overtime

Increased overtime creates additional workload and adverse effects for existing employees, which in turn results in employee turnover. The response to YUB-YEC-1-37 (c) (Exhibit 4, PDF pp. 201-202) shows higher actual 2024 labour costs compared to 2024 approved costs and notes the difference relates to higher actual overtime costs compared to forecast in that year. Yukon Energy notes that it estimated the required 2024 workload conservatively in the 2023/24 GRA in an effort to minimize rate impacts. However, in reality, there have been higher than expected work requirements and overtime costs. This is also evident from a comparison of 2025 actuals with the 2025 test year forecast.

- YUB-YEC-1-37 (c) (Exhibit 4, PDF pp. 201-202) notes that GRA forecasts were based on a relatively normal level of diesel generation and a normal vacancy factor. However, low water levels and snowfall in winter 2024/25 resulted in higher than expected diesel generation in 2025. Yukon Energy consequently incurred a significant amount of overtime to run and maintain the diesel engines. Additional hours running the diesel engines resulted in higher labour expense, including additional overtime ($650,000 more than budgeted). This is expected to continue into 2026, and potentially 2027.[44]

- YUB-YEC-1-38 (b) and (c) note a vacancy factor of 5.01 for the first six months of 2025, to June 30, 2025, which is significantly less than the five-year average of 9.91, resulting in approximately $250,000 (net of assumed lower overall overtime) higher labour expense in 2025.

Overtime requirements were reviewed at the oral hearing and Yukon Energy provided further clarifications, including the following:

- In response to questions from Board counsel about actual overtime costs incurred in 2023 and 2024 exceeding 2023/24 GRA forecasts, Mr. Epp reiterated that Yukon Energy sets high targets to minimize impact on rates, and clarified further that, when Yukon Energy experienced higher overtime costs than anticipated, that cost was borne by Yukon Energy' shareholder and not by ratepayers (transcript page 138, lines 13-20; page 139, line 23 to page 140, line 5).

- Mr. Epp explained (transcript page 142, lines 6-22) that Yukon Energy took a similar approach in the current GRA: to set high targets with respect to overtime in order to minimize impact on rates, in recognition of the fact that Yukon Energy can face challenges in achieving those targets. This includes the challenge presented by increasing high levels of workload that are contributed to by continuing low water conditions. Mr. Epp clarified

[44] See also transcript page 139, lines 9 to 22.

further (transcript page 154, lines 18-21) that Yukon Energy assumed normal water conditions when setting overtime targets in the current GRA.

- Mr. Epp also commented further (transcript, page 139, lines 1-8) on the vacancy factor being one of the main factors affecting overtime. For example, the actual vacancy factor for 2023 was 12.32, which exceeded the 2023 approved vacancy factor by about 3.32 (as shown in Table 3.4, Exhibit 1-A, PDF p. 70). That exceedance represented more than 6,000 employee hours, which resulted in more overtime because the work for those vacant positions still needed to be done. At the same, Mr. Epp noted further that, while adding more FTEs has some impact on reducing overtime, the amount of overtime also depends on the type of work expected to be done (transcript page 151, 20-24) and that some overtime costs cannot be eliminated (transcript page 153, lines 2-5).

- Mr. Milner commented specifically on the unavoidable need for overtime when required to complete critical maintenance, noting that "there's always going to be a certain amount of overtime baked into just the nature of the work" (transcript page 143, lines 1-9). Mr. Milner also emphasized "that workload is not staying flat, in fact we're scrambling to keep up with workload" (transcript page 191, lines 4 to 6). As an illustrative example of this, Mr. Murchison noted that, in addition to emergency work, "in 2024 and then into 2025, we dealt with three unplanned events…resulting in hours that were not planned" (transcript page 145, lines 1 to 7).[45]

Positions Replacing Outside Consultant or Contractor

Yukon Energy has noted that its increased employee complement is largely due to its effort, where possible, to do more work internally as opposed to hiring outside consultants and contractors. Mr. Epp also commented generally at the oral hearing on how increasing FTEs contributes to reducing consulting costs, as well as reducing overtime – and, conversely, on how an insufficient employee complement is certain to result in increased consulting costs, as well as increased overtime (transcript page 153, line 23 to page 154, line 5). Specific examples were also provided in the Application (Exhibit 1-A, PDF p. 72), in IR responses (see YUB-YEC-1-12 (c) (Exhibit 4, PDF p. 148); YUB-YEC-1-43 (a) and (b) (Exhibit 4, PDF pp. 221-223); YUB-YEC-1-51 (b), (Exhibit 4, PDF pp. 256-257); YUB-YEC-1-53 (f) (Exhibit 4, PDF p. 263)) and at the oral hearing (transcript page 188, lines 1-25; page 192, line 17 to page 194, line 8).

Appendix 3.2 and the response to YUB-YEC-1-53 (f) identify several specific employee complement additions that will replace work performed by contractors. YUB-YEC-1-53 (f) also notes that the increased employee complement is necessary to manage the higher workload and ensure that essential tasks, which would otherwise go unfinished due to limited resources, can be completed. Yukon Energy has determined the work that needs to be done, and if the positions are not filled by FTEs, the work will need to be done by contractors.

At the oral hearing, Mr. Milner also emphasized the impact of increasingly high levels of workload, noting that "we've been crystal clear throughout this hearing and throughout our application that workload is not staying flat, in fact we're scrambling to keep up with workload", and the likelihood

[45] The three unplanned events identified were the failure of one Aishihik unit, the failure of a penstock in Mayo, and the failure of a reactor at the Takhini substation (transcript page 145, lines 2 to 6).

that Yukon Energy will still have to spend more money on contractors despite FTE additions, simply because of the rate the workload itself is increasing (transcript page 191, lines 2-23).

Capital/Maintenance Allocation

The 2024 approved revenue requirement forecasts include a capital to maintenance allocation set at 17.9% capital and 82.1% maintenance (the 2024 actual was 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 of each employee's time to perform their job based on corporate goals and expectations and an overall increase in capital projects volumes.[46] YUB-YEC-1-39 (b) (Exhibit 4, PDF pp. 208-210) clarifies that Yukon Energy is not 'proposing' a capital to maintenance allocation percentage. This percentage is simply a resulting statistic that is calculated based on a more detailed labour budgeting exercise. It is not a ratio that is determined and then allocated to labour costs.

2.2.2.2 Production

Approximately 74% of the forecast increase in 2027 over 2024 approved for production cost is due to higher labour cost ($2.413 million increase in 2027 over 2024 approved). Total non-labour production costs for 2027, excluding fuel and purchased power costs, are forecast to be $0.831 million higher than approved 2024 costs (see Table 3.5, Exhibit 1-A, PDF p. 73). Almost 73% of the increase in non-labour expense forecast in 2027 over 2024 approved is due to diesel generation related expenses almost entirely accounted for by increased diesel rental costs (Exhibit 1-A, PDF p. 74).

No material issues were raised during interrogatories or the oral hearing with regard to the balance of the non-labour production cost increases which were related to hydro, LNG and diesel generation [excluding diesel rental costs discussed below], and operation supervision.

Variances in Diesel Rentals Non-Labour Costs

The response to YUB-YEC-1-37 (d) (Exhibit 4, PDF pp. 202-204) notes that non-labour costs will vary from test year forecasts. The Application noted (Exhibit 1-A, PDF p. 76) that "Yukon Energy is currently negotiating the diesel rental contract for the period that commences after expiry of the current contract in April 2025," and included assumptions about the expected terms of the new contract. Subsequent to filing the Application, negotiations resulted in a two-year contract at total costs that varied from what was included in the Application; Yukon Energy had assumed a 2% escalation rate, but the final contract had a 4% escalation rate. Updated diesel rental costs reflecting this change as provided in response to YUB-YEC-37 (d) (Exhibit 4, PDF p. 204) are included in the updated test year revenue requirements provided in the response to Undertaking #13 filed on October 28, 2025.

[46] Application page 3-12 (Exhibit 1-A, PDF p. 73).

Low Water Impacts on Other Related Non-Fuel Thermal Costs

Forecasts for 2025 through 2027 in the May Application were based on a relatively normal level of diesel generation (see YUB-YEC-1-37 (d), Exhibit 4, PDF p. 203). Diesel generation was materially higher than forecast in 2025 due to low water levels and a low snowfall in winter 2024/25. As a result, Yukon Energy incurred a significant amount of overtime to run and maintain the diesel engines. As at June 30, 2025, Yukon Energy's diesel generation exceeded planned diesel generation by 116%. These variances resulted in additional non-fuel diesel generation expenses, such as consumables that are based on runtime hours, of $650,000 more than budgeted. Exceptionally low water levels at Aishihik, and updated inflow forecasts that show 40% lower than normal, indicate that this is expected to continue into 2026, and potentially 2027. Updated diesel maintenance costs based on this new information as provided in response to YUB-YEC-37 (d) (Exhibit 4, PDF p. 203) are included in the updated test year revenue requirements provided in the response to Undertaking #13 filed on October 28, 2025.

2.2.2.3 Transmission and Distribution

Total transmission and distribution costs in 2027 are forecast to be $0.171 million above the approved 2024 costs. Approximately 50% of this forecast increase is due to labour ($0.085 million increase in 2027 over 2024 approved); changes in labour costs over 2024 approved costs are impacted by assumed stabilization of overtime costs.

The majority of the transmission and distribution expense is focused on brushing. Brushing activities are based on Yukon Energy's brushing policy and brushing plans, which fluctuate year-to-year based on the planned activities.

During the IR process and oral hearing, differences in actual and approved brushing costs were reviewed:

- YUB-YEC-1-41 (a) (Exhibit 4, PDF pp. 215-216) provided a correction to Table 3.7.2 Distribution Costs, which also resulted in changes to Table 3.6 (a corrected version of this table was also provided). The changes are to Brushing Cost and Other Non-Labour in the Preliminary Actual 2024 column of both tables; the identified formula error does not impact other numbers in the Application as the change in Brushing Cost is offset by the change in Other Non-Labour.
- YUB-YEC-1-64 (a) (Exhibit 4, PDF pp. 348-350) provides an update to brushing costs. The response notes variances between total work accomplished in 2024 and activities recommended in the Vegetation Management Plan provided by ATCO; it also provides an update on significant variances from the application in 2025 that are expected to impact 2026 brushing maintenance expenses. Yukon Energy's Application forecasts for 2025 through 2027 were based on the ATCO Vegetation Management Plan. However, complexities during procurement of 2025 transmission brushing activities resulted in the cancellation of transmission procurement at the end of the process. As a result, a significant amount of brushing maintenance that was expected to occur in 2025 has been shifted to 2026 (in addition to the work already planned for 2026).

Yukon Energy's forecast brushing cost included in the Application was based on the best information available at the time. However, as Yukon Energy has revised its 2025 and 2026 plans, brushing costs for 2025 and 2026 are now forecast to vary from those submitted in the Application.

The result as provided in YUB-YEC-1-64 (a) (Exhibit 4, PDF p. 350) is $0.461 million lower cost in 2025 and a $0.461 million higher cost in 2026; this new information is reflected in the updated test year revenue requirements provided in response to Undertaking #13.

In summary, the transmission and distribution expense forecasts for the test years are reasonable and should be accepted.

2.2.2.4 Capital Project Studies

In the 2023/24 GRA the Board expressed concern over capitalizing costs for projects without confirmed viability, the occurrence of AFUDC, the desire for clearer, more prudent capitalization policies and the need for consistent treatment across major and minor deferred capital projects.[47] In response, Yukon Energy developed a new policy (FX-001 Criteria for Capitalization)[48] through research of International Financial Reporting Standards and industry guidance. It requires the expensing of costs that do not meet the capitalization criteria.

This comprehensive review and policy overhaul resulted in the creation of a Capital Project Studies budget for early-stage projects. As described in Section 3.3.5.1 of the Application (Exhibit 1-A, PDF pp. 86-88), the annual budget of $1 million was set based on an amount lower than the average historical spending on Feasibility Studies excluding large projects. This approach, which is conservative based on historical data, reduces ratepayer burden and eliminates AFUDC on early-stage projects. It reduces the risk of ratepayers funding projects that may never proceed.

In YUB-YEC-1-45 (Exhibit 4, PDF pp. 227-235) and in day 2 of the oral hearing, the Board had questions about the actual spend of capital project studies. As described on transcript page 235, Mr. Epp responded that actual spending to September 30, 2025, was $375,000 with a forecast of approximately $1.1 million to be expensed in 2025. Upon further questioning, Mr. Epp indicated that the updated forecast of $1.041 million was accurate as the invoicing for studies is typically not done until the full study is complete, so Yukon Energy is expecting to get invoices near the end of the year for all work performed in 2025.

The annual Capital Project Study amount of $1 million proposed in the Application is likely to be insufficient in 2025 and future years.

2.2.2.5 Insurance

In Section 3.3.6.1 of the Application (Exhibit 1-A, PDF pp. 89-91), Yukon Energy explained that insurance costs are expected to increase primarily due to recent insurance claims. Yukon Energy forecast insurance costs of $2.993 million for 2025, $3.329 million for 2026 and $3.393 million for 2027. As insurance renewals are mid-year, the 2025 renewal rate results in a larger than normal increase for 2026, while insurance increases are expected to become normalized in 2027 with an increase of 1.9%.

During the IR process, changes to forecast insurance costs were reviewed:

[47] See, for example, Board Order 2024-05, paragraphs 227, 310, 312, 325-326, 342-343 and 345; Appendix 1, directions 12, 20 and 22; Appendix 2, direction 5.
[48] Application, Appendix 5.3 (Exhibit 1-A, PDF pp. 431-438).

- YUB-YEC-1-47 (d) (Exhibit 4, PDF pp. 239-240) provided an update for property insurance where the deductible was increased, resulting in a new property insurance policy with significantly lower premium cost than if there had been no change in deductible. Based on the same escalation rate that was assumed in the Application, the 2026 and 2027 insurance expense is also now forecast to be less than submitted in the Application. The net changes to forecast insurance costs are a reduction of $0.282 million in 2025, a reduction of $0.316 million in 2026 and a reduction of $0.326 million in 2027.

During the oral hearing (transcript pages 219-220), Mr. Epp commented on how Yukon Energy was incurring additional costs to adapt to the higher deductible level, but did not provide specific details of cost updates. Yukon Energy is not proposing to add those additional costs to its revenue requirement.

2.2.3 Rate Base, Depreciation and Amortization

2.2.3.1 Rate Base

Yukon Energy's 2025 mid-year forecast net rate base in the 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) and 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) as detailed in Section 3.5 of the Application (Exhibit 1-A, PDF p. 102).

The impact of corrections and updated information provided in response to Undertaking #13 reduces the forecast mid-year net rate base to $408.3 million in 2025 ($0.3 million reduction), $515.2 million in 2026 ($1.1 million reduction) and $607.8 million in 2027 ($11.1 million reduction).

The final rate base may change based on the Board's approval of capital projects, depreciation and amortization expenses as well as other expenses included in the revenue requirements that impact the calculation of the working capital requirements.

2.2.3.2 Depreciation and Amortization Expenses

Depreciation and amortization costs net of contributions are forecast in Section 3.4 of the Application (Exhibit 1-A, PDF p. 93) at $20.3 million in the 2025 test year (an increase of $5.6 million over 2024 approved) reflecting changes in plant in service as well as the change in the depreciation calculation methodology for rate setting purposes. Further details regarding the impact of these changes is provided in YUB-YEC-1-50 (Exhibit 4, PDF pp. 244-255). Depreciation and amortization costs net of contributions are forecast at $24.2 million in the 2026 test year (an increase of $3.9 million over 2025 forecast). Depreciation and amortization costs net of contributions are forecast at $26.4 million in the 2027 test year (an increase of $2.2 million over 2026 forecast).

The impact of corrections and updated information provided in response to Undertaking #13 increases the forecast depreciation and amortization costs net of contributions to $20.9 million in 2025 ($0.6 million increase), $25.5 million in 2026 ($1.3 million increase) and $27.9 million in 2027 ($1.5 million increase).

2.2.3.2.1 Depreciation Expense Calculation

As detailed in Section 3.4.1 of the Application (Exhibit 1-A, PDF pp. 93-94), Yukon Energy has changed its method for calculating depreciation and amortization expenses for the 2025-2027 test years based on directives provided by the Board in the 2023/24 GRA. Specifically:

- In Board Order 2024-13, the Board highlighted (at paragraph 16) the "apparent lack of depreciation expense on current year forecast capital additions" and further stated (at paragraph 20): "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." In compliance with this direction from the Board, in the current GRA, Yukon Energy has added depreciation and amortization expenses for the current year capital additions that would not previously have been included, including deferred costs, based on the mid-year approach described by the Board. The detailed calculations are provided in Schedule 3A and Schedule 3B of Application Tab 7 [Exhibit 1-A, PDF pp. 497-505].

- In Board Order 2024-05, the Board directed Yukon Energy (at paragraph 189) to file a revised Schedule 3A with the insertion of "a column indicating the depreciation rate being used" and the inclusion of "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." In the 2023/24 GRA Compliance Filing (PDF p. 32), Yukon Energy noted that it uses Microsoft Great Plains to track its assets and calculate depreciation and amortization, and that the 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 (PDF p. 33) that to simplify the Board's review process, in future GRAs, the calculation of depreciation expenses for forecast years would be based on an approach that applies the approved depreciation rate to the total prior year asset cost for each asset class to calculate depreciation expense for the test years on an asset class by asset class basis. Yukon Energy also noted that this would also be consistent with how AEY forecasts depreciation expenses in its GRAs [see Schedule 7.2 of AEY's 2023/24 GRA]; it would also be consistent with how depreciation rates are determined in the depreciation study [i.e., based on a group of assets in the asset class, regardless of whether or not a particular asset is fully depreciated]. Accordingly, Schedule 3A in Tab 7 of the current Application [Exhibit 1-A, PDF pp. 497-502] provides details of the depreciation expense calculations for each of the 2025, 2026 and 2027 test years as described above: specifically, the asset cost by asset class for the prior year multiplied by the depreciation rate.

- During the oral hearing [transcript pp. 445-446], Mr. Epp explained why the depreciation method was changed for this Application, including the fact that in previous GRAs, when Yukon Energy used an asset-by-asset approach to calculate depreciation expense, it made it more difficult for the Board to understand the depreciation calculations, which led to the above-noted directives. Mr. Epp noted that Yukon Energy is not aware of any utility that calculates depreciation for rate making purposes on an asset-by-asset basis; he also explained how the methodology used in the current GRA for rate making purposes will differ from actual results at year end based on normal financial accounting rules [an example of which was provided in response to YUB-YEC-1-65 (m) (Exhibit 4, PDF p. 357)].

In summary, the depreciation and amortization expenses for the 2025, 2026 and 2027 test years are calculated consistent with the methodology described in the 2023/24 GRA Compliance Filing, which takes into account the directives provided by the Board.

The final depreciation and amortization expenses may change based on the Board's approval of capital projects.

2.2.3.2.2 Net Salvage Study

As detailed in section 3.4.1 of the Application (Exhibit 1-A, PDF pp. 100-101), Yukon Energy maintains a provision for future removal and site restoration costs related to property, plant and equipment. In Board Order 2005-12 (p. 48), the Board directed Yukon Energy to notify intervenors and interested parties when the balance of the provision reaches $2.0 million. 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 Net Salvage Study[49] explored two alternative options in regard to the net salvage provisions:

- the "Traditional Approach", as used by Yukon Energy before 2005; and
- the "Capitalization Approach" used in a number of other Canadian jurisdictions, which reduces impact on rates by capitalizing the costs of net salvage and removal as part of any new replacement project, and only accruing in rates sufficient funding to address removal costs when no direct replacement project will be undertaken (i.e. "terminal retirements").

The Net Salvage Study results show that under the Traditional Approach, the annual net salvage provisions would be about $4.742 million, whereas the Capitalization Approach would yield annual net salvage provisions of approximately $0.350 million (based on 0.042% of gross plant).[50]

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. The annual appropriation of $0.350 million is included as a separate line item under depreciation expense without requiring a change in depreciation rates [see Table 3.13 in Exhibit 1-A, PDF page 93].

The recommendation to use the Capitalization Approach is based on the outcome of the Net Salvage study that notes [Exhibit 4, PDF pp. 440-441] that it is the most common alternative to the

[49] The final updated version of the Net Salvage Study is provided in YUB-YEC-1-68 Attachment 1 (Exhibit 4, PDF pp. 429-448).
[50] The annual accrual rate of 0.042% reflects a reasonable estimate for routine terminal retirements alone (excluding interim retirements) based on the average annual ratio of FRSR spending to gross PPE spending between 2005 and 2023, as shown in Table 3 of the Net Salvage Study (Exhibit 4, PDF p. 443).

Traditional Approach, and that 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 who will be served by the second generation of the asset. The study also notes that taking into account the above factors, a number of regulators ultimately decided 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 (although the specific implementation details differ to some degree among the main utility examples included in the study).

During the oral hearing, Board counsel questioned the authors of the Net Salvage Study on the proposed approach, including treatment of routine and non-routine retirements, and interim and terminal retirements. Specifically, the following were noted:

- Mr. Bowman [transcript page 478] clarified that “the idea is to set up in rates accruals that focus on the routine things”; that “if there's something really big and unusual, it's not covered by $350,000 a year” and “it will have to have its own treatment”; and that Yukon Energy will come back to the Board with a proposal for the treatment of those large ticket costs when they occur or are expected to occur.

- Mr. Bowman [transcript page 436] also stated that: “in general, if it's something that's being removed from a site, but that equipment or that service is still required, so that something new is being constructed at that site or being installed at that site to replace the function of the old asset, then it would be considered an interim retirement.”

- Mr. Bowman [transcript page 461] also noted that, under the proposed Capitalization Approach, all interim removal-type costs associated with interim retirements would become part of the capital costs of the new asset being built in that location, and that the interim does not really have a distinction between routine and non-routine.

Board counsel also questioned Yukon Energy during the oral hearing about the impact of loss on disposal to the net salvage and FRSR, with reference to an example of $46,000 related to the Protection Relay Test Set that was not working properly and was replaced by a new Protection Relay Test Set. In that example, Yukon Energy recorded loss on disposal of $46,000 based on the asset cost of $63,000 and accumulated depreciation of $17,000 [response to YUB-YEC-1-65 (d) (Exhibit 4, PDF p. 355)]. Mr. Epp clarified that this loss on disposal does not appear in the revenue requirements for 2025, 2026 or 2027, and that Yukon Energy is not claiming that amount to be recovered from customers [transcript pp. 433 and 434]. Mr. Bowman [transcript p. 435] also clarified that the loss on disposal is “different than what we talk about when we move to the net salvage study and the net salvage approach, which is where we're talking about a new set of costs that is incurred in order to remove or rehabilitate a site when you remove an asset”, and Mr. Mahmudov provided further clarification [transcript p. 478] that “the net salvage study and proposed recommendations are about the cost of removal associated with retirements. It's not about the retirements themselves.”

The Net Salvage Study also clarifies the issue around the overlap of FRSR with the IFRS Asset Retirement Obligation (“ARO”). The study specifically notes the following [Exhibit 4, PDF p. 443]:

> 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 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.

In response to YUB-YEC-1-66 (f) [Exhibit 4, PDF p. 418], Yukon Energy noted that all assets are assessed in an ARO assessment, but that Yukon Energy's only existing asset that meets the definition of an ARO is the Energy Storage System Land Lease, with an ARO of approximately $20,000 that was calculated based on estimated reclamation costs of $100,000 [in 2025$], estimated life of asset of 50 years, and a benchmark discount rate of 3.28%. That response further clarified that Yukon Energy has not established an internal level of materiality; however, the Office of the Auditor General of Canada determined that an ARO of $20,000 is immaterial. In response to YUB-YEC-1-65 (e) [Exhibit 4, PDF p. 356], Yukon Energy also noted that the Office of the Auditor General of Canada agrees with Yukon Energy that it does not have any asset retirement obligations that need to be recorded.

In conclusion, Yukon Energy is requesting approval of the Capitalization Approach, which will yield annual net salvage provisions of approximately $0.350 million. This will have a much lower rate impact than would result from applying the Traditional Approach, which would yield annual net salvage provisions of about $4.742 million.

2.2.3.2.3 Amortization for WRGS and MGS Relicensing

In response to YUB-YEC-1-50 (b) [Exhibit 4, PDF pp. 251-252], Yukon Energy noted that amortization periods for the Whitehorse Rapids Generating Station (WRGS) and Mayo Generating Station (MGS) Water Use Licence Renewals in Application Tab 7, Schedule 3B – 2025, Schedule 3B – 2026 and Schedule 3B – 2027 were incorrect. The amortization for WRGS should be 20 years [as noted in Appendix 5.2A, Section 5.2A-1], not 25 years as shown in the schedules, while the amortization period for MGS should be 5 years [as noted in Appendix 5.2A, Section 5.2A-3], not 25 years shown in the schedules. These corrections increase the amortization expenses for 2025 [$0.637 million], 2026 [$1.273 million] and 2027 [$1.273 million] and there will be offsetting reductions in the return on rate base due to the reduction of the net rate base [net of amortization]. Yukon Energy noted that it will reflect these corrections in the compliance filing.

In Exhibit 5 (PDF pp. 1-2), Yukon Energy provided further information on the impact of these corrections, specifically noting that the increase in the amortization expenses will reduce the net mid-year rate base for 2025 by $0.3 million, for 2026 by $1.3 million and for 2027 by $2.6 million, with resulting reductions in return on rate base. Therefore, the net impact from these corrections will be $0.620 million increase in the revenue requirement for 2025, $1.200 million increase for 2026, and $1.118 million increase for 2027.

As noted further in Exhibit 5, the cumulative impact of these corrections, together with the $0.067 million reduction in the 2025 revenue requirement resulting from use of the correct deemed 60/40 debt to equity ratio for that test year (as noted in UCG-YEC-1-8 (a) and (c)) is a $0.544 million increase in revenue shortfall for 2025 [-$0.076M+$0.620M], a $1.200 million increase in revenue shortfall for 2026, and a $1.118 million increase in revenue shortfall for 2027. These details are also reflected in Yukon Energy's response to Undertaking #13.

As indicated above, Yukon Energy will reflect these corrections in the compliance filing.

2.2.3.2.4 Amortization of Lewes River Boat Lock Insurance Gain

As detailed in Section 3.4.3 of the Application (Exhibit 1-A, PDF p. 95), Yukon Energy incurred damages and costs to the Lewes River Boat Lock due to the largest ever recorded flooding event along the Yukon River in 2021.

As indicated in response to YUB-YEC-1-50 (d) (Exhibit 4, PDF p. 253), Yukon Energy received insurance proceeds of $4.520 million, while incurring costs of $20,000 relating to the insurance recovery, resulting in a net gain of $4.500 million. In response to YUB-YEC-1-50 (e) (Exhibit 4, PDF p. 253), Yukon Energy further clarified that upon further investigation and analysis, it was concluded that the insurance proceeds are directly related to the old Lewes River Boat Lock asset and are not tied to the future build (if any), and that the Office of the Auditor General of Canada has determined that the insurance proceeds were to be recorded as revenue for IFRS purposes.

For rate-setting purposes, Yukon Energy is proposing that the gain of $4.5 million be amortized over the 3-year term of this Application, being 2025, 2026 and 2027, which reduce the resulting rate impacts in each test year. In response to YUB-YEC-1-50 (f) (Exhibit 4, PDF p. 254), Yukon Energy noted that if the insurance claim were to be recognized entirely in 2025 as opposed to over three years, the revenue requirement for 2025 would be reduced by $3.0 million but would be increased by $1.5 million in both 2026 and 2027.

Accordingly, it is Yukon Energy's position that amortizing the net insurance proceeds of $4.5 million over three years is more appropriate.

2.2.4 Return on Rate Base

No major issues were raised in IRs or at the oral hearing regarding return on equity (ROE), capital structure for rate base financing or forecast interest rates (outside of questions regarding CAFN debt noted below). Yukon Energy will address any issues raised by intervenors in argument during reply.

Retain 2024 Approved Return on Equity (9.15%) and Deemed Equity (40%)

The forecast ROE for the test years is proposed at 9.15%, equal to the 2024 approved rate. As reviewed in Application Tab 8 (Exhibit 1-A, PDF pp. 519-521), the proposed ROE for the test years is based on the methods and approach approved by the Board in the last GRA in the absence of any new evidence warranting a change in the last approved ROE. Yukon Energy is therefore not seeking any changes in approach or in the 9.15% ROE. No material questions or issues on ROE were raised by the Board or other parties during IRs or during the oral hearing.[51] As such the proposed ROE should be approved as requested.

Capital Structure

In Board Order 2024-05 (Appendix A, paragraph 199), the Board approved Yukon Energy's capital structure of 60 per cent debt and 40 per cent equity as reasonable and consistent with past practice. There is no new evidence that could warrants a change in the capital structure at this time, nor did the Board or intervenors raise any questions in IRs or at the oral hearing on this topic. As such the capital structure should be approved as requested.

Long Term Cost of Debt

The cost of debt is reviewed in Section 3.5.1 of the Application (Exhibit 1-A, PDF pp. 104-105). The response to YUB-YEC-1-55 (Exhibit 4, PDF pp. 329-330) also provided clarifications regarding how the short term debt and long term debt are determined.[52]

Additional questions were raised in IRs and at the oral hearing (transcript pages 106-109) regarding the CAFN debt noted in the Application Table 3.15.1: Outstanding Debt (Exhibit 1-A, PDF p. 104). Further details were provided in YUB-YEC-1-54 (Exhibit 4, PDF pp. 327-328) and in Yukon Energy's response to Undertaking #39 filed October 28, 2025 (as well as footnote 4 in Section 3.5.1 of the Application, Exhibit 1-A, PDF p. 104).

In summary, the CAFN $1.0 million long-term debt is associated with the installation of the third hydro turbine at the Aishihik hydro plant. This investment opportunity was negotiated in accordance with CAFN's treaty rights under Chapter 22 of the CAFN Final Agreement – specifically, in section 4.0 (Strategic Investments) of Schedule A. Those rights were honoured as part of the AGS Relicensing Project Agreement signed July 21, 2022, as indicated in YUB-YEC-1-54 (a) (Exhibit 4, PDF p. 327) and reconfirmed by Ms. Cunha during the oral hearing [October 23, 2025 transcript, page 411 lines 9-14].

Amongst other things, the applicable provisions of CAFN's Final Agreement required CAFN to be given an option to acquire an interest in the installation of the third hydro turbine on terms and conditions no less favourable than those applying to Yukon Energy itself as project proponent. Consistent with those provisions, the interest rate on the CAFN debenture was pegged to YEC's actual return on equity for its utility regulatory income, as explained previously in YUB-YEC-1-54 (c) (Exhibit 4, PDF pp. 327-328), which also noted actual Yukon Energy ROEs of 3.52% in 2019 and 2.73% in 2020.

[51] Exhibit 4, UCG-YEC-1-8 (Exhibit 4, PDF pp. 91-95) requested information regarding analysis of operational performance compared to other utilities, best practices within the utility industry, Table 8.1 and Table 8.2 and rationale for comparisons to FEI and AEY, reliability reports, investments aimed at reducing transmission losses and generation reliability constraints and methods to communicate tariff and fee changes to end users.

[52] As noted in Application Section 3.5.1, 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, in accordance with Board Order 2018-10. The Application referred to the Government of Canada Long-Term Bond Benchmark of 3.35% as of January 28, 2025; as noted further in YUB-YEC-1-55, that benchmark rate was 3.56% as of June 30, 2025 (3.56%), and there is no separate rate for 2025, 2026 and 2027. The cost of debt from YDC is based on the market rate at the time the agreement is entered into. The market rate was provided by TD Bank, which was selected as the most recent lender to win the procurement for new debt as they had the lowest rate.

While this opportunity was committed to in 2022, it took both parties a year to negotiate and sign the debt agreement. Although Yukon Energy entered into the debt agreement with CAFN on July 21, 2023, the information was not available at the time of preparation of the 2023/24 GRA. As reviewed in response to Undertaking #39 filed October 28, 2025, YEC informed the YUB for the first time as part of the 2025-27 GRA that the applicable CAFN debt interest rate is tied to Yukon Energy's ROE, which is proposed for the current GRA test years at 9.15%.

2.3 TAB 5 – CAPITAL PROJECTS

Tab 5 of the Application (Exhibit 1-A) reviews capital project investments forecast to be added to rate base in the 2025, 2026 and 2027 test years compared to 2024 approved rate base, as well as capital spending forecast to remain as work in progress at the end of 2027.

Increased capital rate base costs in the Application (before updates) account for $27.993 million (63.6%) of the Application's 2027 revenue shortfall through higher depreciation, interest and equity return costs[53] due to growth of $245.479 million in net mid-year rate base (before working capital costs) from 2024 approved.[54]

Tab 5 reviews forecast capital spending before and after contributions, and prior to any depreciation or amortization expenses, for two categories:

- Capital works (property, plant and equipment), addressed in Tab 5, Section 5.2; and
- Deferred costs (planning and study costs, regulatory and licensing activities, and dam safety reviews), addressed in Tab 5, Section 5.3.

Section 5.4 of Tab 5 also reviews changes in projects reviewed and approved in the 2023/24 GRA, and emergent capital projects not forecast in the 2023/24 GRA, with variances greater than $100,000 added to rate base for the 2025-27 GRA. In accordance with the Board's directions in Board Order 2025-12, Yukon Energy also provided additional information to address gaps identified by the Board in Section 5.4, as well as further information confirming actual versus preliminary actual 2024 costs, providing details on 2023/24 GRA related "other costs" less than $100,000, and regarding projects remaining in work in progress (WIP) after 2027, in Exhibit 2-A, Supplementary Information filed June 30, 2025.

The majority of capital expenditure forecast to be added to rate base by the end of the 2027 test year as provided in the May 2025 Application relate to major projects over $2 million which account (before any updates reviewed below) for approximately $298.5 million or about 86% of the net addition to rate base for the years 2025-2027 (net of 2023/24 GRA additions/contributions and before test year depreciation/amortization) while projects with costs between $0.4 million and $2.0

[53] Application, Table 1-4 (Exhibit 1-A, PDF p. 33). Table 1-4 shows increased capital rate base costs in 2027 over 2024 approved of $27.993 million out of a total 2027 revenue shortfall of $44.045 million, before considering changes to long-term debt interest rates or ROE percent of rate base, and before applying the other updates and corrections provided to the Board after filing of the Application.

[54] Application, Table 3.14 (Exhibit 1-A, PDF p. 102). Table 3.14 also shows a further $1.355 million increase in working capital cost contribution to mid-year rate base in 2027 test year compared with approved 2024.

million add approximately $35 million and projects with costs less than $0.4 million add approximately $14 million.[55]

Key issues raised by the Board in the current GRA proceeding are addressed separately below where relevant for major and other capital projects impacting rate base and test year revenue requirements, as well as for major projects remaining in WIP. Transcript and undertaking references containing more detailed information on these issues are also referenced.

Updates and corrections to the May 2025 Application Tab 5 capital projects that were provided in Yukon Energy responses to supplementary information requests from the Board (Exhibit 2-A), in IR responses (Exhibits 4 and 5), in subsequent Yukon Energy filings prior to the oral hearing (Exhibits 3 and 8), or during the oral hearing, are reviewed in Yukon Energy's response to Undertaking #13 filed October 28, 2025, and are addressed further below where relevant to determination of test year revenue requirements and/or WIP remaining in 2027. The capital project updates affecting rate base are in 2027, involving two major capital projects (with the Wareham Dam Spillway Project – Tunnel removed from 2027 rate base, and the Whitehorse Power Centres Project – South Centre added). The net impact of these updates is to reduce total net rate base additions by end of 2027 (before depreciation/amortization) by approximately $17 million.[56]

As outlined further below, the evidence before the Board in this proceeding supports the reasonableness of all of Yukon Energy's proposed additions to rate base in the 2025, 2026 and 2027 test years, as updated in the response to Undertaking #13 or otherwise identified below.[57] Yukon Energy requests the Board's approval of those rate base additions.

Preliminary Issue: Changes in Projects Approved in 2023/24 GRA

Yukon Energy's Supplementary Information filed June 30, 2025 (Exhibit 2-A) and several Board IRs (including YUB-YEC-1-75 to 82, Exhibit 4, PDF pp. 477-503) focus on documenting and explaining changes in projects approved in the 2023/24 GRA. As reviewed below, pre-2025 changes in projects approved in the 2023/24 GRA do not provide any additional material 2025-2027 rate base increases beyond those already identified in the current Application.

The response to YUB-YEC-1-75 provides 2023/24 GRA forecast versus actual variance added to Yukon Energy's rate base, along with explanations, for 24 of the 30 completed projects with spending over $400k as described in Table 1 from Board Order 2025-12 Appendix A. The six remaining projects from the same Table 1 plus one other project are each addressed separately in responses to YUB-YEC-1-76 through to YUB-YEC-1-82.

[55] Exhibit 1-A, Table 5.8 (PDF pp. 228-233); see also Exhibit 8, p. 2. Tab 5 separately reviews each major project forecast to be added to rate base by 2027 with details in Appendices 5.1A (capital projects) and 5.2A (deferred cost projects); Appendices 5.1B and 5.2B provide separate forecast reviews for all other projects with costs over $400,000. Appendix 5.3 provides FX-001 Criteria for Capitalization. Appendix 5.4A and 5.4B address capital and deferred projects >$400,000 remaining in WIP in 2027. Appendix 5.5 reviews changes in projects from the 2023/24 GRA.

[56] Undertaking #13 filed October 28, 2025, Table 1 (see also Section 1.2 of this Final Argument). In-service for Wareham Dam Spillway – Tunnel project is delayed into 2028, removing this project's $73.9 million from 2027 rate base additions. In-service for Whitehorse Power Centres – South Power Centre is now forecast for completion in 2027 and included in 2027 rate base with $56.9 million cost.

[57] See, specifically, further update below on MGS relicensing in-service date delay from 2025 to 2026.

- YUB-YEC-1-75 (Exhibit 4, PDF pp. 477-484) shows an overall increased 2023-2024 cost variance for the 24 projects reviewed of approximately $2.468 million; however, when the Mayo Lake Enhanced Storage (MLES) project with its $2.267 million variance is removed, the variance for the other 23 projects is only approximately $0.201 million.
    - As noted in the response to this IR, the MLES project was not included in the 2023/24 GRA rate base, i.e., it remained in WIP. The MPES was cancelled in 2024, as reviewed in Appendix 5.2A-4 of the Application (PDF page 407), and is included in the 2025-2027 Application as a cancelled project to be amortized over 10 years (see below for further review).

- YUB-YEC-1-76 (Exhibit 4, PDF pp. 485-488) reviews a 2023-2024 cost variance of $1.654 million for the Thermal Replacement (16.5 MW) project, noting that this major project was addressed in the Application in Appendix 5.1A, and that the variance in 2023-2024 was explained. In summary, the forecast 2023-2024 costs included both approved amounts for rate base and also WIP for future additions to rate base (with forecast further cost to occur in 2025) – and due to issues identified during commissioning of the two Faro units, the entire Thermal Project (aside from closed amounts in 2023-2024 totaling $0.991 million relating to feasibility studies [Exhibit 2-A, page 3]) was kept in WIP at the end of 2024. The final actual costs included in the Application are shown to have been required and prudent.

- YUB-YEC-1-77 (Exhibit 4, PDF pp. 489-492) reviews an asserted 2023-2024 cost variance of $2.216 million for the 2023 Mayo-Dawson Diesel Infrastructure project (as named in the 2023-2024 GRA – in the 2025-2027 GRA this same project is renamed the Mayo Mobile Diesel Genset project). The amounts relate only to costs incurred prior to 2025, and are not explained in the Application. A key point not recognized in the IR response (but shown in Exhibit 2-A, Attachment 1) is that the 2023-2024 GRA approved $5.290 million for 2023 and $0.410 million for 2024 – and therefore, actual costs show no variance from approved costs for 2023, and added costs of only $0.816 million for 2024. The reasons for these added costs, which were reasonably and prudently incurred, are reviewed in response to YUB-YEC-1-77.

- YUB-YEC-1-78 (Exhibit 4, PDF pp. 493-494) reviews an asserted 2023-2024 cost variance of $0.46 million for the Lewes River Boat Lock Road Access Rebuild project. This project was not included in the original Table 1 from Board Order 2025-12, Appendix A, and the IR response noted that this project is different from the Lewes River Boat Lock project that is in Table 1 and the Application (Table 5.2-4 at PDF p. 197, and Appendix 5.1B, Section 5.1B-1.1 at PDF p. 301, with stage 1 costs of $1.640 million forecast to be added to rate base in 2025 and amortized over 10 years). Neither of these two projects was included in the approved 2023-2024 GRA costs, and no costs for Lewes River Boat Lock Road Access Rebuild are included in the 2025-2027 GRA rate base forecast.

- The four remaining projects are each reviewed in responses to YUB-YEC-1-79 to YUB-YEC-1-82 (Exhibit 4, PDF pp. 495-503), each with 2023-2024 cost variance of between $0.033 million and $0.376 million (total cost variance of $0.737 million).

Preliminary Issue: Projects Remaining in Work-in-Progress (WIP)

Yukon Energy has provided responses to supplementary information requests, cross-examination and undertakings to extend 2027 WIP cost forecasts to expected project completion beyond 2027:

- The Table on page 7 of Exhibit 2-A provides forecast 2027 closing WIP and post 2027 spending forecasts for capital projects with expected costs in excess of $400,000.
- Undertaking #35 and Exhibit 21 (YUB Aid to Questioning #13) include the following three major projects remaining in WIP at the end of 2027 with forecast costs to completion from Exhibit 2-A totalling approximately $252 million:
    - Wareham Dam Spillway Full Replacement at $77.0 million for completion 2028/2029;
    - Whitehorse Power Centres Project as addressed earlier at $114.2 million for completion 2029/30 [including Phase 1 that is now forecast to be completed in 2027]; and
    - Mayo MH0 Plant Renewal at $60.5 million for completion 2030/2031.
- Undertaking #33 provides an updated forecast for Whitehorse Power Centres project to 2035 (including Phase 3) of $520.1 million. Undertaking #32 also confirms that the forecast cost of $56.9 million for Phase 1 (15 MW South Centre) has been retained in the 2025-2027 Application update, and noting that a further $9.1 million for AFUDC and a portion of planning costs to end of 2027 will be included in the next GRA.
- Undertaking #38 provides an updated budget for the Wareham Dam Spillway Tunnel option of $110.7 million for completion now forecast in 2028 (the Application forecast completion in 2027 at $73.94 million).

Information on project costs remaining in WIP at the end of 2027 does not affect Yukon Energy's 2025-2027 GRA forecast for test year revenue requirements, revenue shortfalls and required rates.

2.3.1 Major Projects > $2 Million Impacting Rate Base

Major capital and deferred cost projects have costs exceeding $2 million, and require Yukon Energy Board review and approval. Summary review is provided below of the latest updated information on the 17 major projects affecting the 2025-2027 GRA forecast rate base, addressing any issues raised in the YUB proceeding on the need, schedule or prudent costs of individual projects. As reviewed above, updates since the May Application have (a) removed from test year forecast in-service the Wareham Dam Spillway Tunnel project that was included in the Application 2027 rate base additions and reviewed in Application Appendix 5.1A, and (b) added to 2027 rate base additions the Whitehorse Power Centres Project Phase 1 15 MW South Power Centre.

2.3.1.1 Major Capital Projects

2.3.1.1.1 Spending on Sustaining Capital & Strengthening the Power System

MH0 Rockslide Stabilization and Remediation ($78.745 million, 2026 in-service)

The MH0 Rockslide Stabilization and Remediation project will stabilize and remediate the rock slope above the MH0 (Mayo A) hydro generation 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 licence and fish passage. Details on the Project's description, the need for the project today, options assessment, expected costs and in-service date, and project justification and cost-benefit assessment are provided in Application Appendix 5.1A, Section 5.1A-3 (Exhibit 1-A, PDF pp. 255-266. Yukon Energy also provided additional information about the project budget and timeline in response to YUB-YEC-1-70 (c-d) iii. (Exhibit 4, p. 461), and the response to Undertaking #36 filed on October 28, 2025 provides the risk register table developed for this project and the Surge Chamber project, which are being executed under a single Prime Contractor (Peter Kiewit Sons ULC).

The cost-benefit assessment of Mayo A rock slope remediation combined with Mayo A surge chamber replacement and Mayo A powerhouse replacement 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 Mayo B operation without Mayo A rockslide stabilization and remediation.[58] As reviewed in Appendix 5.1A PDF pages 262 to 263, the decision to retain or abandon the Mayo A hydro plant extends beyond cost considerations, with significant implications for energy reliability, environmental sustainability, and grid stability. Water management is also a critical factor in this decision as retention of Mayo A enhances use versus spilling of available water at Mayo.

No material issues were raised in IRs or at the oral hearing regarding this project.

MH0 Surge Chamber Replacement ($27.831 million, 2026 in-service)

The MH0 Surge Chamber project will replace, 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 and Remediation project by the same contractor for both projects. Details on the Project's description, the need for the project today, project justification, options assessment, and expected costs and in-service date are provided in Application Appendix 5.1A, Section 5.1A-5 (Exhibit 1-A, PDF pp. 272-275). Yukon Energy also provided additional information about the project budget and timeline in response to YUB-YEC-1-70 (c-d) iv. (Exhibit 4, pp. 461-462),

The cost-benefit assessment of Mayo A rock slope remediation combined with Mayo A surge chamber replacement and Mayo A powerhouse replacement confirms the overall net benefit of

[58] The cost-benefit assessment as shown in Table 5.1A-15 of Exhibit 1-A at PDF p. 261 (supported by Attachment 5.1A-1, PDF pp. 264-266) shows a net benefit savings (2025$) over 75 years of $15.1 million with only winter generation of Mayo A (9.2 GWh/year) being replaced with thermal if the replacement and remediation is not carried out.

retaining Mayo A powerhouse capabilities for the next 75+ years versus the option of measures to replace Mayo A with thermal generation and retain Mayo B operation without Mayo A rockslide stabilization and remediation.[59]

No material issues were raised in IRs or at the oral hearing regarding this project.

Other Major Capital Projects

Below is summary information on the remaining seven major capital projects listed in Tables 5.2-2 and 5.2-3 (Exhibit 1-A, PDF p. 196) with test year rate base additions between $2.050 million and $6.500 million for sustaining capital and strengthening the power system. No material issues were raised in IRs or at the oral hearing regarding these seven projects.

- Transmission Line Refurbishment L178 ($6.500 million, 2027 in-service) – Project details provided in Application Appendix 5.1A, Section 5.1A-6 (Exhibit 1-A, PDF pp. 276-279).

- Dawson Voltage Conversion – Phase 2 ($3.921 million net of $1.871 million previously approved in 2024 for 2023/24 GRA, 2025 in-service) – Project details provided in Application Appendix 5.1A, Section 5.1A-7 (Exhibit 1-A, PDF pp. 280-282).

- Transmission Line Hazard Tree Reduction and ROW Widening ($2.850 million, allocated equally for 2025, 2026 and 2025 in-service) – Project details provided in Application Appendix 5.1A, Section 5.1A-8 (Exhibit 1-A, PDF pp. 283-287); additional information about project budget and timeline provided in response to YUB-YEC-1-70 (c-d) viii. (Exhibit 4, PDF pp. 464-465).

- Spare Power Transformer Program ($2.675 million, 2027 in-service) – Project details provided in Application Appendix 5.1A, Section 5.1A-9 (Exhibit 1-A, PDF pp. 288-292); additional information about project budget and timeline provided in response to YUB-YEC-1-70 (c-d) vii. (Exhibit 4, PDF p. 464).

- Dam Safety Review Mitigations ($2.600 million, allocated $0.3 million 2025 in-service, $1.2 million 2026 in-service, and $1.1 million 2027 in-service) – Project details provided in Application Appendix 5.1A, Section 5.1A-10 (Exhibit 1-A, PDF pp. 293-294); additional information about project budget and timeline provided in response to YUB-YEC-1-70 (c-d) vi. (Exhibit 4, PDF pp. 463-464).

- WH3 Head Gate Replacement ($2.535 million, 2025 in-service) – Project details provided in Application Appendix 5.1A, Section 5.1A-11 (Exhibit 1-A, PDF pp. 295-297); additional information about project budget and timeline provided in response to YUB-YEC-1-70 (c-d) v. (Exhibit 4, PDF pp. 462-463).

- WH3 10-Year Overhaul ($2.050 million, 2027 in-service) – Project details provided in Application Appendix 5.1A, Section 5.1A-12 (Exhibit 1-A, PDF pp. 298-299); additional

[59] The cost-benefit assessment as shown in Table 5.1A-15 of Exhibit 1-A at PDF p. 261 (supported by Attachment 5.1A-1, PDF pp. 264-266) shows a net benefit savings (2025$) over 75 years of $15.1 million with only winter generation of Mayo A (9.2 GWh/year) being replaced with thermal if the replacement and remediation is not carried out.

information about planned hydro overhauls generally provided in response to YUB-YEC-1-85 (Exhibit 4, PDF pp. 519-521).

2.3.1.1.2 Capital Spending to Address Supply of Dependable Winter Power

Whitehorse Power Centres Project ($56.873 million per Undertaking #32, 2027 in-service)

The Whitehorse Power Centres (WPC) Project as described in the WPCP Update in YUB-YEC-1-8 (a-b) Attachment 1 (Exhibit 4, PDF pp. 131-137) will develop three thermal power centre sites and one new substation in the Whitehorse area in three completion phases though to winter 2035/36 to provide dependable winter capacity as needed for the YIS. The WPCP Update provides an update to the project description that was originally provided in Application Appendix 5.4A, Section 5.4A-1 (Exhibit 1-A, PDF page pp. 440-444). Additional information is also provided in YUB-YEC-1-69 (a-b) i. (Exhibit 4, PDF pp. 451-453) and in the responses to Undertakings #32 and 33 filed October 28, 2025.

The 2027 test year rate base addition that is now forecast from the WPC Project (as reflected in Table 1 in Undertaking #13, Attachment 1) relates to the 15 MW diesel Phase 1 development at the South Power Centre, which Yukon Energy now forecasts to be required in service by winter 2027/28 to meet YIS dependable capacity requirements.[60]

As confirmed in Yukon Energy's October 17, 2025 Opening Statement (Exhibit 8), based on the most current available peak load forecast updates provided since the May 2025 filing of the Application, Yukon Energy must accelerate completion of the first phase of the WPC Project to bring 15 MW of diesel capacity at the South Power Centre into service by December 2027. As summarized in Exhibit 8 (page 3-4), the addition of forecast costs of $56.873 for the WPC Project to Yukon Energy's rate base in 2027 will ensure Yukon Energy's ability to meet the 8.1 MW dependable capacity shortfall now forecast for winter 2027/28, while displacing the need for four forecast diesel rental units for that winter. This results in a projected increase in Yukon Energy's 2027 revenue requirement of $2.415 million (for depreciation and return on mid-year rate base), before applying a reduction in diesel rental costs estimated at $0.214 million for 2027.

As noted by Ms. Cunha at the oral hearing (transcript, page 37, lines 6-20), it will not be possible for Yukon Energy to meet the increased dependable capacity shortfall now forecast for winter 2027/28 by adding additional diesel rental units to the ten that are currently installed at Yukon Energy's Whitehorse plant, as there is no physical space remaining at the existing site to install additional units. Construction of the South Power Centre site will need to be completed by December 2027 to provide physical space to add additional diesel generation capacity in Whitehorse.

[60] The project description originally provided for this project (then called the "Whitehorse Expansion Project") in the May 2025 Application, Appendix 5.4A, Section 5.4A-1 (Exhibit 1-A, PDF page pp. 440-444) contemplated the project remaining in WIP as of the end of 2027. However, Yukon Energy provided updated information to the Board in its August 26, 2025 responses to IRs (Exhibit 4) indicating that the first phase of the WPC project (a 15 MW diesel capacity in-service at the South Power Centre) would be needed by winter 2027/28. Accordingly, the Exhibit 5 cover letter filed September 19, 2025 summarized the Phase 1 WPC project impact on test year revenue requirements – and that Phase 1 revenue requirement impact estimate was further updated in the Opening Statement (Exhibit 8) filed October 17, 2025. The further updated revenue requirement impact estimate is reflected in Yukon Energy's response to Undertaking #13 filed October 28, 2025.

The following further issues related to the WPC South Centre project were addressed during the oral hearing:

- Summary review of the WPC Project updates developed since the May Application, including clarification as to the current 2027 in-service capital cost estimate of $56.9 million in comparison with earlier cost estimates provided in Exhibit 2-A and Exhibit 4, YUB-YEC-1-69 (transcript pages 351 to 356).

- Undertaking #32 as filed October 28, 2025 provides details by year and cost component for the $56.9 million capital cost forecast for the 15 MW Phase 1 of the WPC project, noting that this cost does not include a portion of the overall WPC planning and AFUDC costs attributable to the South Power Centre. The undertaking confirms that Yukon Energy will not change the requested amount for the current 2025-2027 GRA and will include those added costs as part of the South Power Centre in the next GRA.[61]

- Mr. Milner, Mr. Murchison, Ms. Cunha and Mr. Epp, in response to cross-examination by Board counsel, described how the 15 MW South Centre WPC Project would be completed by December 2027, in light the ongoing growth in Yukon Energy's work load (transcript pages 358 to 368). Key information provided included the following:

    - Mr. Milner noted the need to prioritize projects needed to meet winter peak load, and the critical need for Phase 1 of the WPC Project to be in-service by winter 2027/28 (transcript 358 line 18 to page 360 line 3).

    - Ms. Cunha described work streams happening in parallel, including securing long-lead items, regulatory assessments and permitting, the establishment of a senior official group to coordinate activities, ongoing engagement with First Nations, identified sites and back-up sites if needed (transcript page 360 line 4 to page 361 line 16).

    - Mr. Murchison provided details on procurement approach and engineering that would enable meeting the required timeline, noting also the ability to install rentals for the first year of the South Power Centre's operation if needed (transcript page 361 line 19 to page 363 line 15). He also indicated Yukon Energy's expectation to complete construction in one construction season, based on past experience with diesel plant work, with a construction start date in late May 2027 (transcript page 367 line 11 to page 368 line 3).

    - Mr. Epp and Ms. Cunha described steps to date and future timelines for a Part 3 review by the Board and for YESAB process completion (transcript page 364 line 23 to page 367 line 4).

On redirect, Ms. Cunha provided further information on the senior officials group composition, its supporting activities for timely completion of the WPC Project Phase 1, Yukon Energy's relevant experience on recent completion of the Callison diesel project, and the expected submission of the

[61] Yukon Energy has also provided updated information on the overall WPC Project schedule, phases and budget estimate through to completion of Phase 3 by winter 2035/36 in its response to Undertaking #33.

YESAB project proposal for WPC Project in March 2026 (transcript page 429 line 2 to page 431 line 25).

In summary, the evidence provided during the oral hearing provided considerable clarification and further information on the WPC South Centre Project. The project's need and feasibility to be completed before December 2027 was confirmed, and no material issues remained outstanding.

Thermal Replacement (16.5 MW) ($43.176 million net of $18.176 million approved in 2024 for 2023/24 GRA, 2025 in-service)

The Thermal Replacement project replaces 12.5 MW of retiring diesel units in Whitehorse, Faro and Dawson, as well as installing an additional 4 MW diesel expansion in Whitehorse, yielding an overall planned diesel expansion of 16.5 MW. Details on the Project's description, project justification and alternatives, scope, schedule and budget are provided in Application Appendix 5.1A, Section 5.1A-1 (Exhibit 1-A, PDF pp. 235-242), with additional information provided in response to YUB-YEC-1-76 (Exhibit 4, PDF pp. 485-488). The justification for the 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. Levelized Cost of Capacity (LCOC) assessments (Exhibit 1-A, PDF p. 242) over a 40-year life for the 16.5 MW diesel replacements 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.

The two 2.5 MW Tier 4 modular diesel units at Faro were expected to be in-service in later 2024, and added $18.176 million to the approved 2024 rate base in the 2023-24 GRA. Due to issues identified during commissioning, in-service of these Faro units was delayed until early 2025 and the project was kept in WIP at the end of 2024. As reviewed in response to YUB-YEC-1-76, several scope changes were required in Faro and Dawson, and these along with other factors resulted in approximately $1.654 million higher costs than forecast in the 2023/24 GRA.

No material issues were raised in IRs or at the oral hearing regarding this project.

Battery Energy Storage System ($18.45 million net of $16.5 million grant contributions, 2026 in-service)

The Battery Storage System (BESS) project is designed to significantly enhance the reliability and capacity of the YIS through the establishment (as updated) 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 starting winter 2026/27 and continuing over a minimum of 20 year life. Details on the Project's description, the earlier Part 3 Application review by the YUB and 2023/24 GRA reviews, project updates, schedule and budget updates, and project justification updates are provided in Application Appendix 5.1A, Section 5.1A-2 (PDF pp. 243-257), with additional information about project budget and schedule provided in response to YUB-YEC-1-70 (c-d) ii. (Exhibit 4, PDF pp. 459-460).

The updated project budget and justification analysis in Appendix 5.1A shows that over the life of the project the net present value ($2025) of the costs is $30.234 million and the net present value of benefits is $40.647 million, indicating net present value savings benefit to Yukon ratepayers of $10.413 million.

The BESS is now scheduled to be commissioned by the contractor in Q4 2025. When the contractor's work is complete, Yukon Energy will take over a site that will need improvements and upgrades to make up for non-critical deficiencies, and Yukon Energy will also need to take some testing of this new asset (i.e., the first BESS operated by Yukon Energy) on the Operations side to get comfortable using it. Accordingly, the BESS will not be ready for its intended use until winter 2026/27, and therefore, will not be added to rate base until 2026.[62]

No material issues were raised in IRs or at the oral hearing regarding this project.

2.3.1.2 Major Deferred Cost Projects

2.3.1.2.1 Spending on Licensing Projects (Sustaining Capital)

WRGS Long Term Water Use Licence Renewal ($10.608 million, in-service 2025)

The WRGS Long Term Water Use Licence Renewal project is to obtain long-term (20-year) project authorizations for the continued operation of the Whitehorse Rapids Generating Station (WRGS), including the Lewes Control Structure, after the May 31, 2025 expiry of Yukon Energy's previous Type A water use licence for this facility. Details on the Project's description, the need for the project today, options assessment, expected costs and in-service date, and project justification, evolving regulatory landscape, strategic and regulatory approach, governance project approach, Project activity summary from initiation in 2021 to April 2025, First Nation interests, energy agreements with First Nations and Yukon government, Project budget and Project costs are provided in Application Appendix 5.2A, Section 5.2A-1 (Exhibit 1-A PDF pp. 372-384).

Yukon Energy's response to YUB-YEC-1-2(a) (Exhibit 4, PDF pp. 109-117) also provide additional information about Yukon Energy's hydro relicensing projects generally, and the WRGS relicensing project in particular. That IR response reviews complexities of hydro relicensing projects generally in the current legal and regulatory environment, and the level of effort experienced by Yukon Energy on the relicensing process for WRGS in particular, that took more than three years of intense effort to obtain a renewed 20-year Water Use Licence that was issued on July 29, 2025 – as well as Yukon Energy's engagement that is still ongoing with Fisheries and Oceans Canada to obtain a *Fisheries Act* Authorization.

YUB-YEC-1-83 (Exhibit 4, PDF pp. 504-514) also provides additional information on WRGS relicensing project costs, Yukon Energy oversight of costs, and engagement programs with First Nations and communities.

No material issues were raised in IRs or at the oral hearing regarding this project.

AGS 25-Year Water Use Licence Renewal ($9.729 million per Exhibit 2-A, Attachment 1, Table 5.8 update, in-service 2027)

The AGS 25-Year Water Use Licence Renewal project is to obtain long-term project authorizations for the continued operation of the Aishihik Generating Station (AGS) after the current 5-year water use licence expires on December 31, 2027. Details on the Project's description, background,

[62] See also YUB-YEC-1-5 and YUB-YEC-1-11 (Exhibit 4, PDF pp. 122, 145) re: BESS reducing diesel rentals starting from 2026/27 winter, and the $16.5 million government contribution impacting 2026 rate base.

previous GRA reviews, engagement, Project activities from 2015 to March 2025, cost control measures, and Project budget are provided in Application Appendix 5.2A, Section 5.2A-2 (Exhibit 1-A, PDF pp. 385-395).

As noted above, Yukon Energy's response to YUB-YEC-1-2(a) (Exhibit 4, PDF pp. 109-117) reviews hydro relicensing complexities and level of effort experienced by Yukon Energy on its recent hydro relicensing processes, including the AGS relicensing processes that Yukon Energy has undertaken since 2015. YUB-YEC-1-83 (Exhibit 4, PDF pp. 504-514) also provides additional information on AGS long-term relicensing project costs, Yukon Energy oversight of costs, and engagement programs with First Nations and communities.

No material issues were raised in IRs or at the oral hearing regarding this project.

MGS 5-Year Water Use Licence Renewal ($7.295 million, in-service 2025)

The MGS 5-Year Water Use Licence Renewal project is to obtain 5-year renewed project authorizations for the continued operation of the Mayo Generating Station (MGS) after the current 25-year Type A water use licence expires on December 31, 2025. Details on the Project's description, evolving regulatory landscape, First Nation interests, strategic and regulatory approach, governance, Project approach (including table setting out scope and major tasks), Project schedule, Project activities from 2022 to March 2025, Project budget, and MGS 5-Year licence renewal costs are provided in Application Appendix 5.2A, Section 5.2A-3 (Exhibit 1-A, PDF pp. 396-406).

As noted above, Yukon Energy's response to YUB-YEC-1-2(a) (Exhibit 4, PDF pp. 109-117) reviews hydro relicensing complexities and level of effort experienced by Yukon Energy on its recent hydro relicensing processes, including the recent MGS relicensing processes. YUB-YEC-1-83 (Exhibit 4, PDF pp. 504-514) also provides additional information on MGS 5-year relicensing project costs, Yukon Energy oversight of costs, and engagement programs with First Nations and communities, and YUB-YEC-1-84(c) (Exhibit 4, PDF p. 518) reviews the basis for transferring $2.336 million in coffer dam remnant removal costs from the Mayo Lake Enhanced Storage Project to the MGS Licence Renewal project.

During the oral hearing Ms. Cunha reported that Yukon Energy had received a decision document from the Yukon government agreeing with the assessor that the 5-year MGS relicensing project as a whole (i.e., including the coffer dam remnant removal and replacements of the Mayo Lake Control Structure) can proceed and that a decision document from DFO that has not yet been received will be very specific to fish (transcript page 317 line 5 to page 318 line 13).

No other material issues were raised in IRs or at the oral hearing regarding this project. Yukon Energy notes, however, that the delays in receiving decision documents for this water use licence renewal have now delayed the Water Board hearing process into early 2026, with the result that in-service for this project now will also be delayed to 2026. If, as a result of this further update, the Board directs that it is appropriate to add the costs of this project to rate base in 2026 instead of 2025, Yukon Energy will reflect that direction in the compliance filing.

Mayo Lake Enhanced Storage Cancellation ($2.267 million, in-service 2024)

The Mayo Lake Enhanced Storage Project (MLESP) cost of $2.267 million is the actual cost of the planning work undertaken on this project to February 2022, net of costs of $2.336 million in 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 cancelled Southern Lakes Storage Enhancement Project, starting January 1, 2025. Details on Project historical activity, Project update (including costs from 2012 to 2022), and Project justification (including basis for stopping AFUDC on the Project effective February 2022) are provided in Application Appendix 5.2A, Section 5.2A-4 (Exhibit 1-A, PDF pp. 407-414).

Yukon Energy's response to YUB-YEC-1-84 (Exhibit 4, PDF pp. 515-518) provides additional information about the cancellation of this project, including a review of the basis for transferring $2.336 million in coffer dam remnant removal costs from this project to the MGS Licence Renewal project, as well as additional information regarding the amortization of remaining capitalized costs over 10 years and relevant schedules in the Application that illustrate the capitalization.

Yukon Energy's response to Undertaking #27 filed on October 28, 2025 further explains that the difference of $42,000 between the amount that Appendix 5.2A indicates as being transferred to the MGS Licence Renewal project and the corresponding line item in Table 5.8 in Exhibit 2-A (PDF p. 34) represents AFUDC that was reversed in 2024 because it was determined to be occurring past the closing date (i.e., it was neither closed out with the MLESP nor transferred to the MGS 5-year Licence Renewal project).

No material issues were raised in IRs or at the oral hearing regarding this project.

2.3.1.2.2 Other Major Deferred Cost Projects

Integrated Resource Plan ($2.332 million, in-service 2026)

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 20 years. The goal is to develop a System Resource Plan that is actionable and likely to be implemented. Details on the Project's description, project justification, project context, Project schedule and budget are provided in Application Appendix 5.2A, Section 5.2A-5 (Exhibit 1-A, PDF pp. 415-419).

No material issues were raised in IRs or at the oral hearing regarding this project.

2.3.2 Other Projects Between $400,000 and $2 Million in Rate Base

The Application forecasts approximately $39.0 million net rate base impact in the 2027 test year over 2024 approved for projects with costs under $2 million and exceeding $400,000, excluding any depreciation or amortization deductions and net of contributions and/or amounts approved in the 2023/24 GRA. No material issues were raised in IRs or at the oral hearing regarding these projects.

1. Appendix 5.1B of the Application (Exhibit 1-A, PDF pp. 300-370), as updated in Exhibit 2-A, Attachment 1, reviews 36 capital projects <$2 million and >$400,000 with 2027 total net rate base impact of approximately $37.3 million, excluding any depreciation or amortization deductions:

    a. Generation Projects – 8 projects with total 2027 rate base increase of $7.760 million in 2027, excluding any depreciation or amortization deductions and net of $1.0 million approved to be in 2024 rate base (2023/24 GRA) for Whitehorse Spillway Stoplog Refurbishment project that was deferred for in-service until 2025.

    b. Transmission Projects – 7 projects with total 2027 rate base increase of $6.456 million, excluding any depreciation or amortization deductions.

    c. Distribution Projects – 6 projects with total 2027 rate base increase of $3.913 million, excluding any depreciation or amortization deductions and net of total contributions of approximately $2.426 million.[63]

    d. General Plant & Equipment Projects – 7 projects with total 2027 rate base increase of $6.178 million, excluding any depreciation or amortization deductions.

    e. Overhauls – 6 projects with total 2027 rate base impact of $7.772 million, excluding any depreciation or amortization.

    f. Intangible Assets - 2 projects with total 2027 rate base impact of $1.820 million, excluding any depreciation or amortization.[64]

2. Appendix 5.2B of the Application reviews 1 deferred project <$2 million and >$400,000 with forecast total net rate base impact in in 2027 of approximately $1.7 million (excluding reductions due to amortization).[65]

    a. Demand Side Management – net rate base impact of $1.656 million, excluding reductions due to amortization, with $0.747 million in 2025, $0.484 million in 2026 and $0.444 million in 2027.

No material issues were raised in IRs or at the oral hearing regarding specific projects in this cost category, and experience shows that delays or cancellations of smaller projects tend to be replaced with new projects such that total in-service impact spending is not materially affected. Evidence also confirmed that projects were being capitalized in accordance with approved financial policy. Yukon Energy will respond in reply argument to any specific issues or questions raised by intervenors regarding any of these projects.

[63] Costs updated per Exhibit 2-A, Attachment 1, Table 5.8.
[64] Costs updated per Exhibit 2-A, Attachment 1, Table 5.8 (includes Tailrace Gate Certification of $0.592 million in 2025).
[65] As updated per Exhibit 2-1, Attachment 1, Table 5.8 (no longer includes $0.714 million in 2025 for AGS *Fisheries Act* Authorization which was included in Application and Appendix 5.2B).

2.4 OTHER MATTERS

2.4.1 Issues Raised by Intervenors

During the oral hearing, Nathaniel Yee questioned Yukon Energy's panel on the following issues:

- Yukon Energy's continued reliance on Dawson diesel generation units DD2 and DD5 for dependable capacity (as shown in NY-YEC-1-1 Attachment 1, Exhibit 4, PDF p. 5), despite the fact that in the 2023/24 GRA those units were noted to be at end of life and were forecast to be retired in 2024-25;

- The absence of any "spare" diesel rental units anywhere in the YIS in Yukon Energy's current Application, despite previous GRAs including spare units to address reliability concerns with the rental diesels;

- The listing of rental diesel units in the table provided in response to NY-YEC-1-2 (Exhibit 4, PDF pp. 6-7) higher in the generation stacking order than the newly installed FD8 and FD9 units, which are Tier 4 units that are more efficient than the Tier 2 rentals (unlike Yukon Energy's older "pre-Tier" units); and

- The status of Yukon Energy's design and installation of noise mitigation for its diesel generators in Faro.

Yukon Energy's evidence in response to these questions is summarized as follows:

1. ***Continued reliance on DD2 and DD5***

Mr. Murchison explained at the oral hearing (transcript page 24, lines 3-17) that, while DD2 and DD5 may be approaching end-of-life, Yukon Energy is not in a position where it can decommission them at this time. Yukon Energy has, however, done general maintenance and repair on both units (including an investment of approximately $100,000 this year in parts for DD5) and it has hired a full-time mechanic in Dawson, which will assist in maintaining both units' reliability.

In response to a further question on this issue from the Board (transcript page 499, lines 17-21), Yukon Energy provided additional information in its response to Undertaking #40 filed October 28, 2025, including clarification of the following details:

- A diesel unit's end-of-life is not dictated by age or specific year per se, but rather the total number of hours that an engine can typically run (barring any earlier major equipment failure). The actual service life in hours varies depending on the operating conditions, maintenance practices, and duty cycle (i.e., load level, duration, and frequency of operation) of the unit. As a result, an engine may operate for more or fewer hours than expected over its lifetime.

- As of September 30, 2025, DD2 has a total runtime of 105,000 hours, exceeding the ordinarily expected service life of 100,000 hours for each diesel engine. However, for the foreseeable future, Yukon Energy requires all sources of dependable winter capacity it has (and more) to meet winter demands for power.[66] Decommissioning a diesel unit without replacing its capacity with another source of diesel capacity at its present location or elsewhere on the system is unlikely.

- The dependable capacity of Yukon Energy's permanent diesel units at each site (as provided in NY-YEC-1-1 Attachment 1) reflects a weighted average Forced Outage Rate, which is determined based on forced outage data for the past five years. For downtown Dawson, Yukon Energy has determined a forced outage rate of 4% for its permanent diesel units. This accounts for the plant's overall reliability taking into account recent operational experience with all existing engines at the site (including DD2 and DD5).

- Yukon Energy has also recently assessed, permitted and enhanced the Callison substation south of Dawson City to include diesel power generation and in anticipation that as diesel engines in downtown Dawson reach end-of-life they would be replaced and relocated at Callison. Given the rapid pace in which demands for power are growing in the Yukon, the total amount of diesel generation installed at both the Callison and downtown Dawson locations over time will depend on demands for power in Dawson City and across the territory, the availability of adequate replacement generation capacity, and investment required to continue operating the Dawson Downtown Diesel Plant.

2. *Absence of spare diesel rentals*

As detailed in Application Tab 2, Section 2.4 (Exhibit 1-A, PDF pp. 52-54), concerns about the reliability of Yukon Energy's diesel rental units are now accounted for by applying the Forced Outage Rates that Yukon Energy has determined for its thermal generation resources, to calculate their effective load carrying capacity as a more accurate measure of their contribution to meeting the grid's reliability target.

For diesel rental units, a Forced Outage Rate of 15% has been assumed in the Application to reflect reliability experience with those units (Exhibit 1-A, PDF p. 53). Accordingly, in the current GRA (as reflected in NY-YEC-1-1 Attachment 1), each diesel rental unit is relied on for 1.53 MW of dependable capacity, instead of its maximum rated winter capacity of 1.8 MW, yielding a total dependable capacity of 33.66 MW for all 22 diesel rental units currently on the system.

Consistent with the above, Ms. Cunha explained at the oral hearing that all 22 of Yukon Energy's existing diesel rental units are now considered to be required to meet N-1 planning criteria based on the forecasts in the Application (transcript page 27, lines 1-10).

3. *Stacking order*

Yukon Energy notes that the table in NY-YEC-1-2 is stated to show the "approximate stacking order" of thermal units for winter 2025/26, and that IR response explains further that "[t]he generation stacking order changes based on available information at the time of generation, including demand, available generation resources, resources required for system stability, air emissions permit and water use licence conditions under normal operating conditions, rental diesel

[66] The table included in the response to Undertaking #40 provides total runtimes as of September 30, 2025 for all diesel engines in downtown Dawson, which range between 24,000 and 73,000 hours for the other five units at that site.

generator contract provisions and other operational considerations at the time (e.g., fuel supply, availability of labour resources, etc.)."

At the oral hearing, Ms. Cunha confirmed that Yukon Energy's air emissions permits contemplate Yukon Energy using the most efficient thermal generation units based on the circumstances; however, she clarified further that "those circumstances can range, based on temperatures, and one of the reasons why the rentals to get used or at least started in advance of permanent assets at times is that we have found that in order for them to be the most reliable during the coldest temperatures being minus 30, minus 35, et cetera, that we must start them early." Accordingly, she explained that, to increase the reliability of the rental units in extreme cold temperatures, "it is now operational practice…for us to start them when temperatures start to get to the minus 20 range" (transcript page 25, lines 17-25).

4. Noise mitigation in Faro

Yukon Energy summarized its plans to address noise issues in Faro in its response to NY-YEC-1-24 (Exhibit 4, PDF p. 76). This included repositioning the rental diesel generators in 2023 so that the loudest part faces away from the town centre, and so that sound is buffered by the building that houses FD1. Yukon Energy also continues to monitor sound levels in the community, and it is investigating options for noise mitigation and will provide an update to the community as more information becomes available.

Mr. Murchison elaborated on these plans at the oral hearing and explained that Yukon Energy has given further consideration to the possibility of installing a sound barrier at the FD7 unit radiators, but found that it was uncertain whether that measure would be effective to provide noise mitigation (transcript page 29, lines 12-16). Mr. Murchison also reiterated Yukon Energy's commitment to install appropriate noise mitigation measures when and if there is an opportunity to do so (transcript page 29, lines 17-22).

Ms. Cunha also emphasized the further evidence in NY-YEC-1-1-24 (Exhibit 4, PDF p. 76) that there is no noise legislation in the Yukon that applies to Yukon Energy and that, in the absence of legislation, Yukon Energy follows the British Columbia Noise Control Best Practices Guidelines, but those Guidelines do not apply in emergency situations where public safety is at risk. In such circumstances, Yukon Energy would run the necessary units to ensure public safety (transcript page 30, lines 11-23).

* * *

Yukon Energy will respond further in its Reply Argument, if necessary, to any additional material issues that Mr. Yee may raise in his Final Argument.

As UCG did not participate in the oral hearing, Yukon Energy will also respond in its Reply Argument to any Final Argument that may be filed by UCG.

2.4.2 Other Issues Raised by the Yukon Utilities Board

Yukon Energy also provides further comments on the following additional issues raised by the Board in this proceeding:

- The potential effect on customer bills if the balance of the Fuel Price Variance Account were to be collected during the test period;

- The current status of the Atlin Hydro SIS and EPA Project (which was proposed in the Application to remain in WIP, as set out in Appendix 5.4B, Section 5.4B-1 (Exhibit 1-A, PDF pp. 466-468));

- Issues raised by the Board with the format of the tables presented in Application Tab 5 respecting capital project expenditures and work in progress continuity schedules; and

- Issues raised by the Board with Yukon Energy's capital project numbering and naming practices.

2.4.2.1 Addressing the Fuel Price Variance Account Balance

During the oral hearing, the Board asked Yukon Energy to advise on the incremental effect on customer bills if YEC were to collect the balance in the Fuel Price Variance Account (FPVA) during the test period, all other things being equal [Undertaking #18, Transcript page 214 line 1 to page 215 line 1]. This request was made with reference to the $5 million FPVA balance indicated in the Rider F – Q2 2025 Quarterly Report filed with the Board on September 29, 2025 (Exhibit 7).

The referenced report shows that the FPVA balance for June 30, 2025 was $5.0 million owing from customers, exceeding the +/- $0.200 million threshold set by the Board. However, the report also noted that the FPVA balance is impacted by the fact that the fuel price variances for 2025 for Yukon Energy were calculated using the last approved fuel prices and efficiencies from the 2023/24 GRA, while the current 2025-27 GRA with 2025, 2026 and 2027 test years are still under review by the Board, with about $4.4 million out of a $5.1 million balance due to 2025 fuel variances for Yukon Energy. The report also noted that, in accordance with past practice, once the fuel prices and efficiencies are approved in the 2025-27 GRA, the fuel price variances in the FPVA will be recalculated with the updated fuel prices and efficiencies, and any outstanding balances will be addressed in due course through final rate revenue approvals and related true-up rate riders, and follow-up Rider F filings.

During the oral hearing, Mr. Epp noted [Transcript page 212 line 18 to page 213 line 5] that:

> .. the last Rider F change was on April 1st, 2025, when it was changed to 0 cents per kilowatt hour. Since then there has been no Rider F, and based on our forecasts -- or then we basically submitted our general rate application, and knowing that there's going to be changes resulting from the Rider F and the request for new fuel prices, until we know what the approved fuel prices are going to be, we've considered it appropriate to not do any rider until that updated balance was known, which won't be known until after your decision letting us know what the approved fuel prices are starting January 1st, 2025.

Mr. Epp also noted that if the fuel prices for the test years are approved as filed, then the June 30, 2025 balance of the FPVA would go from about $5 million down to $1.9 million, taking into account the actual fuel prices for the reporting period [Transcript page 213 lines 16-18, page 214, lines 5-8].

Yukon Energy's response to Undertaking #18 then provided the typical residential customer bill impact of collecting the balance over a 9-month period (about 1.9%) or, alternatively, over a 12-month period (about 1.3%), noting the following:

- The amount in question was related to the balance to June 30, 2025. The year-end balance and/or the balance at the time of the final decision by the Board on Yukon Energy's 2025-27 GRA would be different than this amount, depending on the actual thermal generation and actual fuel prices.

- During the Oral Hearing, Mr. Epp also highlighted the methods of collecting the balance from customers, either as part of the GRA true-up rider or as a separate Rider F rider [Transcript page 214 lines 13-18]. Regardless of the method of collection, the bill impact would be the same, as the riders (Rider F or the true-up rider) would target the same amount to be collected.

As indicated in the undertaking response, the bill impact will not be affected by the choice of collection method (Rider F or the true-up rider) because either rider would target the same amount to be collected.

Considering that the FPVA balance is related to the fuel variances compared to the approved prices, Yukon Energy requests that the remaining balance be addressed through Rider F, and not through the GRA true-up rider. This would also be consistent with the aim to reduce the true-up amount to be collected from customers. Accordingly, Yukon Energy intends to submit (together with AEY) a Rider F filing to the Board that will address the FPVA balance once the 2025-27 GRA fuel prices are approved.

2.4.2.2 Atlin Hydro SIS and EPA Project Status

In the Application (Exhibit 1-A, PDF page 467), Yukon Energy noted that in the 2023/24 GRA Compliance Filing, due to significant uncertainties, Yukon Energy could not confirm that there was a reasonable probability that the Atlin Hydro Expansion project would proceed, but that ongoing work continued to be demonstrated for the project. Under those circumstances, according to Yukon Energy's current practice, it would not cancel the project and would maintain the project cost in CWIP. However, Yukon Energy also noted in the 2023/24 GRA Compliance Filing that if the Board's review of the above information concludes that the cost should be expensed in accordance with the directives provided in paragraphs 312 and 326 of Board Order 2024-05 (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 maintained the project cost in CWIP.

During the oral hearing process for the current GRA, Yukon Energy provided further clarification and information about the status of this project, including the following:

- Transcript page 339: Ms. Cunha noted that in preparation for this hearing, Yukon Energy received an update from the proponent as of September 30, 2025. Detailed information on the status update received from the proponent was then filed in response to Undertaking #29, showing the progress made to move forward with the project.

- Transcript pages 344-345: Mr. Milner noted that Yukon Energy “can't confirm that it will proceed or not proceed because it's entirely outside of our control. What we can do is stay in touch with the proponent, watch the project, watch for indicators, they are making significant investments in this project, like in the millions of dollars.” Mr. Milner also noted that “this is the kind of project that we want to see on the system. It's winter capacity and winter energy at the same time, and we're doing our part within reason to sort of keep the EPA alive.”

- Transcript page 345: Mr. Milner further noted that the proponent has “made some progress with the BC government through permits and as well as the ongoing financial support through the BC government. So there's reason to believe they're advancing it on their side, and we have to do a cost benefit analysis on whether or not to keep the EPA alive in its current form, through conditions precedent, which is largely administrative legal process for us or to close it and then open it up again, once there's more certainty on the project.”

- Transcript page 346, line 7-14: Mr. Epp noted that if the project would likely not proceed and then Yukon Energy would close this project as it exists and ask for it to be recovered through rates, and if, however, it was subsequently reopened or there was progress by the proponent, then Yukon Energy would have to start it as a new project.

- Transcript pages 347-348: Mr. Epp further clarified that if the project cost to date is closed, then Yukon Energy would recommend that the net amount be included either as an expense or alternatively amortized the cost over a 10-year period, consistent with the approaches previously taken for the projects with costs of more than $1 million. Mr. Epp further noted that the conditions precedent have been extended to early 2026, which may therefore be a more appropriate closing date for the project.

In summary, the project is still being pursued, and it is premature for Yukon Energy to confirm, with certainty, whether or not the project will ultimately proceed. At this time, it is Yukon Energy's position that there is still uncertainty about the project's ultimate viability.

If the Board decides based on this evidence that the project costs to date should be closed, Yukon Energy would propose to reflect that change in the compliance filing by closing the project in 2026 with amortization of the net rate base over 10 years to minimize rate impacts during the test years.

2.4.2.3 Tab 5 Tables and Capital Project Explanations

In the course of this proceeding, the Board has raised the following issues with the format of Tab 5 tables:

- In paragraph 45 of Appendix A of Board Order 2025-12, the Board directed Yukon Energy to provide a capital work in progress (CWIP) continuity schedule consistent with the direction provided in Board Order 2024-05 Appendix A Errata, which is to include columns showing approved forecast amounts for the years 2023 and 2024.

- During the oral hearing, the Board asked Yukon Energy to provide a disaggregated breakdown of spending on projects under $400,000 in Table 5.8 of Tab 5, which was provided in response to Undertaking #21.

- The Board has raised concerns about the apparent absence of variance explanations for some projects' actual spending compared to the approved forecasts in the GRA [for example, in YUB-YEC-1-76 (a), YUB-YEC-1-77 (a), YUB-YEC-1-78 (a), YUB-YEC-1-79 (a), YUB-YEC-1-80 (a), YUB-YEC-1-81 (a) and YUB-YEC-1-82 (a)].

- Board counsel questioned Yukon Energy's panel at the oral hearing about project cost estimate classes for major projects, with reference to YUB Aids to Questioning #13 and 14 (Exhibits 21 and 22).

In light of the foregoing, Yukon Energy proposes to take the following approach in future general rate applications to simplify and assist the Board's review process, unless the Board directs otherwise:

- Yukon Energy will provide only two tables in Tab 5, specifically Table 5.1 and a CWIP continuity table in the format of Table 5.8 as filed in Exhibit 2-A [which would become Table 5.2], including the approved forecasts in the previous GRA, actual spending and forecast spending for the test years.

- Yukon Energy will provide a detailed list of projects by function, in the format of Table 5.8 as filed in Exhibit 2-A for major projects, projects with a total cost over $2 million, and projects with a cost between $0.4 million and $2 million, with project write-ups for each project, including the variance explanations for the projects included in the previous GRA, where the actual spending varies from the approved forecast by more than $100,000.

- In that table, Yukon Energy will also provide a list of projects with a cost below $0.4 million. However, no project write-ups will be included in the GRA. If the Board or intervenors have any questions regarding the specific projects listed under $0.4 million, Yukon Energy will then provide responses during the IR process.

- In project write-ups, Yukon Energy will also include information on the cost estimate classes for the major projects with a total cost over $2 million.

- Yukon Energy will also provide the project total costs and expected service dates for the projects with the total cost over $0.4 million that remain in WIP in the format of the table provided in Exhibit 2-A, PDF page 7.

2.4.2.4 Capital Project Naming & Numbering

During the IR process, the Board questioned the capital project numbering and naming practice. In response to YUB-YEC-1-73 (a) [Exhibit 4, PDF page 473], Yukon Energy provided an explanation of how the capital projects are numbered and named. Specifically, Yukon Energy noted that the capital project numbering system is a manual process where new projects are assigned a Project Identification (PID) Number in the format "Pyr-###", where "yr' represents the year of the project creation and "###" project's sequential ordering. For example, the first PID assigned in 2025 was

P25-001. Yukon Energy also noted that the names for PID's can change from the initial project name if it is determined that a different name is more appropriate based on the project scope.

During the oral hearing, Mr. Epp and Mr. Murchison provided further explanations regarding the project numbering and naming, specifically:

- Transcript page 291, Mr. Epp noted that the names for PIDs can change as the project evolves, and provided an example referring to the Whitehorse Power Centre, which was described as the Whitehorse Power Expansion project at the time the Application was prepared and filed in May 2025. Yukon Energy now refers to this project as the Whitehorse Power Centre based on project description that was filed with YESAB.

- Transcript pages 296, Mr. Murchison: "When you look at projects and capital projects, we do have a capital project registry that lists all of our capital projects and that capital project registry includes projects that are currently in our capital plan, future projects as well, so there is a long list of capital projects that are within the capital projects registry that we have."

- Transcript pages 297-298, Mr. Murchison: "The projects that are then approved go through an approval process so that PID is formed for those projects, so then each project gets a PID and then there's a next layer of approval where we have essentially an approve for expenditures that happens on all those projects after they are approved. So we have a large list, not all the projects are approved. The projects that are approved in our capital plan then go through a process where senior management as identified actually approves those PIDs and then once a PID is approved, project managers can spend on those projects. They can't spend before the PID is approved."

- Transcript page 298, Mr. Epp: "Within each PID we then create a capital job, a C number, for the various different components of the project. Some projects may have one capital job. Some projects may have several capital projects. So that's how we distinguish the various different stages of a larger project."

As outlined above, Yukon Energy has a robust system that tracks its capital projects; however, Yukon Energy understands that changes in project names may create some challenges when GRAs are filed and the Board and intervenors try to reconcile information about projects referred to in previous proceedings. Therefore, in future GRAs, Yukon Energy will provide an explanation for the projects where the project names have been changed compared to information previously filed with the Board.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Jason Herbert
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