

September 28, 2023

AEY-YUB-041

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-041

Reference: 2023-24 GRA Schedules, S9.2 – Continuity of Capital Expenditures

Issue: Capital expenditures

Preamble: The Board has been unable to fully cross reference certain capital cost information between the business cases that have been provided and the information in 2023-24 GRA Schedules, S9.2 – Continuity of Capital Expenditures.

Request:

- (a) For the following line no. references from S9.2, please provide a reference to the applicable business case where details supporting the capital expenditure have been provided. If no business case had been prepared for the costs at issue, please provide detail supporting the capital expenditures on the noted line no. To the extent that the information requested in this IR has been provided in response to another Board IR, please cross-reference that IR response.
- (i) Line No. 134 – Renewables – Old Crow (2019, \$1.034 million; 2020, \$1.147 million; 2021, \$1.406 million; and 2022, \$0.034 million);
 - (ii) Line No. 161 – Mt. Sima Hill Service (2022, \$0.413 million);
 - (iii) Line No. 167 – YG Airport Hangar (2022, \$0.562 million; 2023, \$-0.030 million);
 - (iv) Line No. 279 – AEY DWCI – New 12.5kV substation (2023, \$0.025 million; 2024, \$0.792 million);
 - (v) Line No. 282 – AEY Nisutlin Bridge Pole Relocation (2023, \$0.380 million; 2024, \$0.165 million)
 - (vi) Line No. 315 – Carcross Streetlights (2017, \$0.429 million; 2018, \$-0.024 million; 2019, \$0.111 million);

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- (vii) Line No. 322 – McIntyre Subdivision Streetlight Rebuild (2023, \$0.412 million; 2024, \$0.155 million);

For Line No. 322, please also explain why AEY had approved 2016-17 costs for this project (\$0.175 million and \$0.254 million, respectively), but no capital expenditures appear to have been incurred.

- (viii) Line No. 419 – Unit 136 to Replace Unit 643 Bucket Truck (2017 \$0.614 million)

- (b) For the following line no. references from S9.2, please provide the requested information

- (i) Line No. 183 – General Pole Replacements. Please explain why historical actuals for 2016-2022 (ranging from \$0.029 million to \$0.112 million each year) are significantly less than approved 2016-17 yearly capital expenditures (\$0.297 million and \$0.284 million respectively).

Please also justify AEY's proposed increases in capital expenditure forecasts for the years 2023-24 (\$0.254 million, \$0.211 million, respectively) given the lower actual costs incurred in 2016-2022.

- (ii) Line No. 186 – General Clearance Upgrades/Fixes. Please explain why historical actuals for 2016-2022 (ranging from \$0.00 million to \$0.037 million per year) are significantly less than approved 2016-17 capital expenditures (\$0.050 million and \$0.051 million respectively).

Please also justify AEY's proposed increases in capital expenditure forecasts for the years 2023-24 (\$0.084 million and \$0.108 million respectively) given the lower actual costs incurred in 2016-2022.

- (iii) Line No. 189 – T&B Switch Change Out. Given that historical actuals for 2016-2022 range from \$0.002 million to \$0.036 million per year, please justify AEY's proposed increases in capital expenditure forecasts for the years 2023-24 (\$0.119 million and \$0.064 million respectively).

- (iv) Line No. 196 – McCrae Substation Second Feeder Breaker. Please provide a variance explanation for the \$0.327 million difference between the actual 2016-17 costs incurred (the total of \$0.608 million and \$0.133 million) compared to the 2016 approved costs of \$0.414 million.

- (v) Line No. 340 – Replacement of Meters and New Installations. Please explain why the actual capital expenditures for the years 2016-17 (\$0.105 million and \$0.088 million respectively) were less than the approved capital

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forecast for this project for the years 2016-17 (\$0.199 million and \$0.203 million respectively).

Please also address the Board's observation that actual capital expenses for this project continued during 2018-2022 (ranging from \$0.032 million to \$0.127 million) at amounts significantly less than being recovered through approved 2017 revenue requirement.

- (vi) Line No. 344 – General Capitalizable Transformers. Please explain why the approved 2016-17 capital expense forecast (\$0.090 million and \$0.091 million respectively) does not appear to have been incurred.

Please also address the Board's observation that AEY proposes capital expenditures for 2023-24 (\$0.218 million and \$0.275 million respectively) notwithstanding that, between the years 2016 and 2022, a total of only \$0.297 million has been incurred on an actual basis for this project.

- (vii) Line No. 345 – Spare 10 MVA Transformer. Please explain why the approved 2016 capital expense forecast (\$0.219 million) does not appear to have been incurred.
- (viii) Line No. 346 Spare Padmount Regulator for Shipyards Substation. Please explain why the approved 2016 capital expense forecast (\$0.058 million) does not appear to have been incurred.

Response:

- (a) (i) A Business Case was not prepared. This is a customer driven fully contributed project. The scope of the project included the purchase of BESS/Micro Grid Controller, new transformer for the PV site, new recloser for the IPP site, foundation design and construction for BESS and various distribution and generation upgrades to accommodate the connection of the IPP to the Old Crow system.
- (ii) A Business Case was not prepared. This is a customer driven fully contributed project, apart from investment in load based on YUB approved amounts. The total investment was below the business case threshold. The scope of the project included extending underground primary power

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comprised of cable in conduit up the Mt. Sima Ski hill to a new padmount transformer.

- (iii) A Business Case was not prepared. This is a customer driven fully contributed project, apart from investment in load based on YUB approved amounts. The total investment was below the business case threshold. The scope of the project includes extending underground primary power comprised of cable in conduit around the Whitehorse Airport runway to a new padmount transformer.
- (iv) A Business Case was not prepared. Applied for expenditures include: design, land acquisition and long lead materials. This project will not be energized or capitalized during the 2023-2024 Test Period.
- (v) A Business Case was not prepared. This project is a highway right of way move requested by the Yukon Government to facilitate the replacement of the Nisutlin Bridge. Our Highways right of way permits state:

Yukon may at any time require the Utility to modify, relocate or remove a portion or all of its physical infrastructure in order for Yukon to facilitate work being done on the highway, to install new or modify existing points of access or intersection, to permit Yukon to use the land, or for any other purpose which Yukon considers to be in Yukon's or the public's interests.

This project includes relocating the existing line along the Nisutlin bridge, as well as distribution infrastructure at 2 intersections being upgraded along the Alaska Highway on the bridge approaches.

- (vi) A Business Case was not prepared. This is a customer driven fully contributed project, apart from investment in new streetlights based on YUB approved amounts. The total investment was below the business case threshold. The scope of the project includes installation of new streetlights

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on wood poles from the Carcross Bridge to the intersection of the Klondike Highway and Tagish Road.

- (vii) Business Case #01 was split into two different line items per S9.2 of the GRA schedules. This split was done to differentiate between asset classes within the project. Table 1 reflects the sum of the 2016 and 2017 approved values included on line 191 and line 322 per schedule S9.2.

Streetlights were unable to be installed while there were still overhead powerlines along the roads. AEY needed to wait until all civil and electrical work was complete and overhead lines were removed before installing streetlights.

- (viii) While preparing responses to IRs, a presentation error in Schedule 9.2 was identified where several items that should have been included in line 417 – Transportation equipment were included in line 419 - Unit 136 to Replace Unit 643 Bucket Truck for the 2017 year. This error only impacts how the information is presented on Schedule 9.2. AEY will update this Schedule in the Compliance Filing to the Application. A summary of the items to be moved is shown below. AEY notes that this project is below the major projects business case threshold of \$500,000. However, in an effort to be helpful, AEY has prepared a Business Case for this project. Please refer to AEY-YUB-041(a)(viii) Attachment 1.

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Table 1: Transportation Equipment Reconciliation

Project Description	Cost (\$)	Original line on Schedule 9.2	Corrected line on Schedule 9.2
2017 H&H Topline Cargo	28,500	419	417
Replace Unit 096	47,482	419	417
Replace Unit 990	48,570	419	417
Replace Unit 776	58,361	419	417
Unit 139 - 2017 Dodge R	24,142	419	417
Unit 138 - 2017 Dodge R	43,610	419	417
Unit 137 - 2017 Dodge R	43,728	419	417
Unit 136- Replace # 643 Bucket Truck	370,883	419	419

- (b) (i) Project scope was reduced in 2016 and 2017, as new extension projects required additional power line technician resources to complete. This impacted AEY's ability to complete the full scope of this project within the prior test period. AEY was able to complete the pole replacement work in subsequent years once resources were available. AEY has created plans to address the backlog of this capital work which is further described in AEY-YUB-042.
- (ii) Project scope was reduced in 2016 and 2017 as new extension projects required additional power line technician resources to complete. This impacted AEY's ability to complete the full scope of this project within the prior test period. AEY was able to complete the pole replacement work in subsequent years once resources were available. AEY has created plans to address the backlog of this capital work which is further described in AEY-YUB-042.
- (iii) Increase to budget due to increased material costs for the switches, as a result of inflation and supply chain issues.
- (iv) Line No. 196 scope was expanded to include the addition of a 10 MVA Padmount Transformer upgrade in the McRae Substation, which was not

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identified in the original project plan. The final cost for the Second Feeder Breaker Project was \$0.431 million.

- (v) There are two types of meters charged to Line No. 340. Meters for new extension customers and meters that require to be replaced. Meters for new extensions, where there is a general service meter or more than one residential meter required, were charged directly to the capital project, instead of to the line-item account for Line 340. The forecast for 2016 to 2017 was based off the 2013 to 2015 time-period average of \$0.236 million per year. There were fewer meters required to be changed and fewer meters for new connections charged to this line item account than expected.

The forecast for the test period is \$0.103 million and \$0.106 million for 2023 and 2024, respectively. This forecast is more in line with the 2016 to 2022 timeframe that average of \$0.85 million for this line item than the previous forecast.

- (vi) Project scope is driven by load growth on distribution transformers in residential neighborhoods. During the years of 2016-17 the load growth impacting existing transformers was not as significant as had been predicted. As the push to electrify residential homes increases, AEY expects that there will be increased requirements to replace transformers in these neighborhoods.
- (vii) While preparing these IR responses, a presentation error in Schedule 9.2 was identified. The spare transformer (\$251,000) was misclassified in Line No. 197 – McCrae Substation Transformer Upgrade to 10 MVA rather than Line No. 345 – Spare 10 MVA Transformer. In addition, the transformer for Line No. 197 – McCrae Substation Transformer Upgrade to 10 MVA (\$300,000) was grouped in Line 196 – McCrae Substation Second Feeder

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Breaker. These errors only impact how information is presented on Schedule 9.2. AEY will update this Schedule in the Compliance Filing to the Application.

- (viii) While preparing these IR responses, a presentation error in Schedule 9.2 was identified. The Shipyards Spare 25kV beaker was misclassified as Line No. 304 Shipyards Spare breaker (\$55,000), instead of Line No. 346 Spare Padmount Regulator for Shipyards Substation. This error only impacts how the information is presented on Schedule 9.2. AEY will update this Schedule in the Compliance Filing to the Application.



2023-2024 General Rate Application (GRA)

Replace Unit 643 – Bucket Truck

2023-2024 Business Case #AEY-YUB-041(a)(viii)

Executive Summary

1. AEY currently operates and maintains 78 vehicles and trailers. It is an important management decision on when to replace this equipment. Given the large service area and cold climate, fleet reliability is essential to system operations.

Background

2. Unit 643 – Bucket Truck is 20 years old; its reliability has been decreasing and maintenance required on it is increasing.

Project Description

3. Replace Unit 643 with a Terex TL50 Hi Ranger Articulating Boom and Freightliner Chassis. Procurement of this vehicle will be through ATCO Fleet.

Project Schedule and Cost

Table 1: Purchased Fleet

Unit	Description	Year Purchased	Purchase Cost (\$)
Unit 136 (Replaces Unit 643)	Freightliner with Ranger Boom	2016	370,883

Business Drivers and Benefits

4. Bucket trucks are required on a regular basis to perform maintenance on overhead and low voltage systems. This unit is required for routine and emergency work as well as assisting with live line procedures when required. AEY's overall overhead assets continue to increase requiring more hours of bucket truck time for maintenance.

5. This vehicle will be available for line crews when their bucket truck is out of service resulting in decreased downtime and increased customer satisfaction. The Operations Department will have the ability to complete small work orders when required, increasing efficiency. The bucket will have a maximum working height of 54.5 ft, giving workers the ability to park off roadway and away from traffic more often, specifically when maintaining 14m streetlights.

Evaluation of Viable Alternatives

Alternative 1

6. Continue to use Unit 643 – the vehicle is over 20 years old, and maintenance required to maintain adequate performance has increased.

Alternative 2

7. Renting or leasing the equipment to support these permanent positions, which is subject to equipment availability. AEY's experience with renting machinery to temporarily fill in for machinery requiring unexpected repairs is that the costs are not economical, and availability is limited.

Recommendation

8. Replacement of Unit 643 with new bucket truck as proposed above.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-042

Reference: 2023-24 GRA, Section 9.1, Capital Additions, PDF page 173, Table 9.1 and paragraphs 2 and 3

Issue: Capital expenditures and additions

**Table 9.1: Capital Expenditures and Additions
(\$000)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Capital Expenditures	14,784	10,527	9,491	13,529	13,001	15,147	18,914	31,234	25,073
Capital Additions to Rate Base	12,079	8,393	11,159	9,982	11,893	11,014	15,857	34,734	31,780
Contributions	(1,241)	(2,204)	(3,212)	(5,969)	(4,220)	(5,250)	(2,529)	(10,119)	(16,431)
Net additions	10,838	6,189	7,947	4,013	7,673	5,764	13,328	24,615	15,349

**Table 9.1: Capital Expenditures and Additions
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Contributions	(1,241)	(2,204)	(3,212)	(5,969)	(4,220)	(5,250)	(2,529)	(10,119)	(16,431)
Net additions	10,838	6,189	7,947	4,013	7,673	5,764	13,328	24,615	15,349

3. Since the last GRA there has been significant load growth in the Yukon (approximately 40 percent increase since 2014), as a result of the rapidly increasing population. This growth has led to the need for AEY's capital program to keep up with the demand, as can be seen in the steadily increasing capital expenditures. This increase was not only required to maintain safe and reliable service but also to strengthen and grow the power system as the demand continues to rise.

Preamble: In paragraph 2, AEY explains that its actual capital additions for the years 2016-17 (\$12.079 million and \$8.393 million, respectively) were overall less than the approved amounts (\$13.823 million and \$12.059 million¹ respectively) "due to the timing of a number of

¹ AEY 2016-2017 GRA Schedules – Compliance Filing, Schedule 8.6.

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projects which were completed in subsequent years.” Further, the Board notes in Table 9.1 that for all years 2018 to 2021, AEY continued to have capital additions that were lower than approved for 2016, notwithstanding its assertion, as quoted above, of a need to strengthen and grow the power system.

Request:

- (a) Given that AEY's actual capital additions in each of the years 2016 to 2021 have been lower than its approved 2016-17 capital additions, please explain in detail the basis for AEY's claim that it actively managed its capital program to keep up with the significant load growth since 2014.
- (b) Given the large increases in capital expenditures and capital additions forecast for 2023-24, can AEY explain in detail how it will be able to complete all the capital work it has set out for itself given the significantly lower amount of capital work completed in the previous seven years?

Response:

- (a) AEY manages a four-year business plan that incorporates all capital expenditures as follows:

Table 1: Capital Management

Appropriation	Driver	Schedule
Distribution New Extensions	Customer driven – Yukon Government, City of Whitehorse, Northwestel	Annual
Distribution Improvements	SAIDI / SAIFI, Line Patrols, Inspections, load studies	Quarterly / Annual / Monthly
Distribution Street and Sentinel Lights	Testing, Inspections	Annual
Distribution Meters	New connects, due for test groups, sample groups	Annual
Distribution Transformers and Regulators	Equipment testing, Inspections	Annual
Tools, Instruments and Equipment	End of life, Reliability, Changes in equipment / technology	Annual / Monthly / Daily
Office Furniture and Equipment	End of life, Inspections	Annual
Office Computer Equipment	End of life, Reliability, Changes in equipment / technology	Annual

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Appropriation	Driver	Schedule
Communications	End of life, Reliability, Changes in equipment / technology	Annual
Transportation Equipment	End of life, Reliability, Inspections	Annual
Land, Building, Leasehold Improvements	Inspections, Assessments	Annual
Generation	End of life, Inspections, Assessment, Reliability	Monthly

AEY's capital plans focus on system performance, reliability, and safety. Assets that are shown to have vulnerability are prioritized to be replaced or rebuilt. AEY has replaced, rebuilt, and upgraded many areas of the distribution and generation power systems, as shown in S. 9.2 L.6-129 and L.182-318, that collectively contribute to a robust power system. These projects included:

- Transformer replacements;
- Regulator replacements / upgrades;
- Reconductoring to larger capacity conductor;
- Streetlight / davit replacements;
- Generator / engine replacements and rebuilds;
- Switch replacements;
- Breaker replacements / additions; and
- Pole replacements.

AEY frequently assesses the electrical system for deficiencies and needed improvements to maintain service. Electrical planning is ongoing and shows the need for these improvements during the test years, as described in the supplied business cases.

Reasons some projects will be completed in 2023-2024 and not earlier include:

- Uncertainty in resources and material during the pandemic;
- Timing implementation of improvements to when they are needed; and
- Increased pole and streetlight testing programs since 2021 resulting in more assets requiring replacement.

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Please refer to the following responses as examples to highlight the planning process AEY uses to determine areas of poor performance, reliability, and safety:

- AEY-YUB-060(a), AEY-YUB-060(a) Attachment 2;
 - AEY-YUB-070(a), AEY-YUB-070(a) Attachment 1;
 - AEY-UCG-071(b), AEY-UCG-071(b) Attachment 1;
 - AEY-UCG-073(b), AEY-UCG-073(b) Attachment 1;
 - AEY-UCG-087(a), AEY-UCG-087(a) Attachment 1; and
 - AEY-UCG-092(a), AEY-UCG-092(a) Attachment 1.
- (b) AEY plans for all identified system work to be completed to maintain service to customers. AEY is procuring or has procured contractor support to accomplish the significant capital plan in the test years. Where appropriate, contractors will be used for engineering, project management, and construction more than in previous years to supplement internal resources. AEY's proposed organizational chart includes additional key resources to execute proposed projects.

Many large projects in the test years require costly pieces of equipment. The material costs of these projects account for a large portion of the budget. Examples include Kluane First Nation Wind Turbine Upgrades, Beaver Creek PV Generation, the substation projects, and regulator projects.

Below AEY has provided the status of a number of large projects as of September 2023 to demonstrate how this capital work is already underway:

- New Substation Mayo Road (S9.2 lines 266 and 272)
 - o Project schedule provided in AEY-YUB-059(a);
 - o Large equipment procured, some delivered; and
 - o Significant cost in large equipment, refer to AEY-YUB-59 Table 3.
- AEY New Substation Whistle Bend – Leota (S9.2 line 281)
 - o Project schedule provided in AEY-YUB-059(a);
 - o Transformer out to tender, other large equipment ordered;
 - o Lands application submitted to YG, YESAB application prepared;

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- o Project management, engineering, construction to be tendered to contractors; and
 - o Significant cost in large equipment, refer to AEY-YUB-59 Table 4.
- AEY 6L19 voltage improvement (S9.2 line 296)
 - o Regulators ordered and in queue for production and delivery in 2024; and
 - o Project cost is mostly material.
- AEY Old Crow Regulators (S9.2 line 348)
 - o Regulators on site in Whitehorse for testing before shipping to site for installation;
 - o Engineering completed; and
 - o Project cost is mostly material and shipping equipment to Old Crow.
- AEY Whitehorse Escarpment line reroutes - 5th avenue (S9.2 line 300)
 - o Engineering and project management contractor hired;
 - o Engineering started;
 - o Discussion with the City of Whitehorse on new alignment ongoing; and
 - o Site visit completed.
- AEY Nisutlin Bridge Pole Relocation (S9.2 line 282)
 - o Engineering complete to IFR stage; and
 - o Project timing depends on bridge construction schedule.
- AEY Voltage Improvement Destruction Bay (S9.2 line 286)
 - o Regulators on site in Whitehorse for testing before shipping to site for installation;
 - o Engineering completed; and
 - o Project cost is mostly material.
- AEY DWCI - New 12.5kV substation
 - o Planning underway for location; and
 - o Listing long lead equipment to be ordered in 2024.
- McIntyre Subdivision Rebuild (S9.2 line 191)
 - o Preliminary engineering done; and

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- o Preparing construction package and tender to be issued in Q1 2024 to secure contractor.
- General Pole Replacements (S9.2 line 183)
 - o Engineering underway for 2024 projects; and
 - o Preparing construction package and tender to be issued in Q1 2024 to secure contractor.
- Whistle Bend 6 (S9.2 line 149)
 - o Under construction now.
- Whistle Bend 7 (S9.2 line 150)
 - o Under construction now.
- Whistle Bend 9 (S9.2 line 152)
 - o Stage 9A under construction now; and
 - o Stage 9B material ordered for 2024.
- Old Crow Bunkhouse replacement (S9.2 line 370)
 - o Planning and pre-lim engineering underway; and
 - o Project cost is mostly material and shipping.
- Watson Lake plant upgrades and modifications, and WL unit 2 overhaul (S9.2 line 26-34, 36)
 - o These projects are near complete.
- Fish Lake upgrades and modifications (S9.2 line 5, 17-19)
 - o These projects are near complete.
- Yukon Government Robert Campbell Highway Streetlights (included in S9.2 line 311)
 - o Construction underway.

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**ATCO Electric Yukon (AEY)
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**Information Responses Round 1 to:
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Received: September 6, 2023**

AEY-YUB-043

Reference: 2023-24 GRA, Section 9.1, Capital Additions, PDF pages 173, paragraph 2, PDF page 174, paragraph 5 and PDF page 181, paragraph 22

Issue: Capital additions

Quote: 2. In this Section, AEY is seeking Board approval of the 2016-2022 actuals on a final basis and approval of its forecasts for 2023 and 2024 additions. Overall, the 2016 and 2017 actuals were below the approved additions mainly due to the timing of a number of projects which were completed in subsequent years.

...

5. ... and Business Cases are provided for significant upcoming projects where certain un-capitalized costs are forecast in the Test Period but capitalized expenditures are forecast subsequent to the Test Period.

...

22. AEY is providing an additional set of Business Cases for capital projects which will not result in capitalized costs during the Test Period, but which are forecast to result in certain un-capitalized costs during the Test Period [or in the years 2016 to 2022] as well as large capital expenditures subsequent to the Test Period. AEY has included these Business Cases in the Application even though costs incurred during the Test Period will not be capitalized, in an effort to be transparent and to notify the Board and other stakeholders regarding larger upcoming capital expenditures. For the purposes of this Application, AEY is seeking Board approval for the un-capitalized costs forecast during the Test Period that are associated with these projects. Any capital expenditures forecast to occur

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subsequent to the Test Period will remain subject to the Board's review and oversight in a future GRA proceeding.

Preamble: It is not clear to the Board what type of expenditures are being referred to in the above quote.

Request:

- (a) Referring to paragraph 5 quoted above, please clarify if AEY's reference to "significant upcoming projects where certain un-capitalized costs are forecast in the Test Period but capitalized expenditures are forecast subsequent to the Test Period" is intended to describe capital expenditures to be accumulated in construction work in progress for projects that will not be recorded as a capital addition until after 2024. If not confirmed, please explain fully.
- (b) Referring to paragraph 22 quoted above, please confirm that AEY is requesting that the Board approve capital cost expenditures that do not yet qualify as a used and useful asset. Please explain whether it/this? conforms with the Board's mandated requirement to test the prudence of AEY's capital asset additions.

Response:

- (a) Confirmed.
- (b) AEY included these project Business Cases in this Application to ensure transparency and to inform the Board and other stakeholders of the anticipated large upcoming capital spend that will be required in order to address aging infrastructure needs and ensure AEY can sustain the provision of safe reliable service for the growing population and resulting load growth. As there is currently no mechanism in the Yukon (for example, compared to a Facility Application in Alberta) to apply for large capital projects. AEY is signaling capital requirements and providing parties opportunity to review the capital requirements. AEY is not seeking approval for the capital expenditures that do not yet qualify as used and useful assets that are to be included in rate base in a future application.

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2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
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Received: September 6, 2023**

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Reference: 2016-17 Business Case #02 – Fish Lake Ditch 1 Failure, PDF page 10, paragraphs 5 and 8

Issue: Capital expenditures (Generation)

Quote: 5. A new structure has been designed with additional loading constraints and non-frost susceptible fill will be used surrounding the spillway. The upgraded structure (betterment) costs will be borne by AEY, while like-for-like costs will be borne by insurance less a \$100,000 deductible.

...

8. The project took 12 weeks to complete and cost \$262,000, net of the insurance proceeds.

Preamble: In the referenced business case, AEY explains that betterment costs will be borne by AEY, while like-for-like costs will be borne by insurance. AEY further states that the cost of the Fish Lake Ditch 1 Failure was \$0.262 million net of insurance but provides no further information respecting the insurance claim and the costs at issue.

Request:

Please provide further detail identifying the project costs “borne by AEY” and those recovered through an insurance claim. In the response, please clarify whether the betterment costs are for AEY shareholders or ratepayers. Please also confirm that this business case and the betterment costs are specific to the Fish Lake Ditch 1 Failure project alone. If not confirmed, please explain fully.

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Response:

Costs covered by the insurance claim include temporary repairs, failure assessments, and like-for-like inflation adjusted rebuild costs. The insurance claim is intended, per the underwritten policy, to replace the loss back to the original condition.

As the spillway structure failed in part due to a deficient design, it would not be prudent to rebuild a spillway structure to the same standard that had failed. Costs to upgrade and improve the spillway structure, over and above the like-for-like replacement costs, are considered a system improvement project and are treated the same as other similar capital projects.

AEY confirms that the Business Case and the betterment costs are specific to Fish Lake Ditch 1 Failure.

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AEY-YUB-045

Reference: 2023-24 GRA, Section 9, PDF page 174; AEY 2016-17 GRA Compliance Filing, Schedule 9.2, PDF page 54

Issue: Capital Expenditures – Generation

Preamble: In AEY's 2016-17 GRA compliance filing, AEY submitted forecast generation plant expenditures of \$2,529,000 for 2017. Actual capital expenditures for generation were \$963,000 in 2017.

Request:

- (a) Please explain the variance of this item for both 2016 and 2017.
- (b) What work was undertaken in 2017?
- (c) Please list all projects included in the 2017 forecast for generation capital expenditures.
- (d) Please explain what happened to the forecast but incomplete generation projects for 2017.

Response:

- (a) Please refer to AEY-YUB-045(a) Attachment 1 for explanations for 2016 and 2017 projects with variances of 10% and greater than \$50,000.
- (b) Please refer to AEY-YUB-045(a) Attachment 1, column F, for a list of projects from 2017.
- (c) Please refer to AEY-YUB-045(a) Attachment 1, column I, for a list of forecast projects for 2017.

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AEY-YUB-045

(d) Although 2017 actuals were lower than approved, the spend related to the approved but incomplete 2017 projects was incurred in prior and subsequent years. As outlined in the table below and in AEY-YUB-045(a) Attachment 1, 2017 Actuals were lower than 2017 Approved by \$1.566 million mainly due to the following:

- Line 2 - Fish Lake 2 Head Pond Spillway Replacement delayed to 2018 (\$0.423 million), due to the unexpected Fish Lake Ditch 1 Failure;
- Line 5 - Fish Lake Unit 1 Spillway Diversion Structure delayed to 2019 and 2020 (\$0.381 million), due to the unexpected Fish Lake Ditch 1 Failure;
- Line 17 - Old Crow Original Plant Rebuild delayed to 2018 due to unexpected floor reinforcement in 2016 (\$0.199 million) and;
- Write-off of cancelled projects (\$0.582 million). It is important to note the cancelled projects were not included in revenue requirement.

**Table 1: 2017 Actuals vs Approved
(\$000)**

	2017			2016-2022
	Actuals	Approved	Variance	Total Project Spend
Fish Lake 2 Head Pond Spillway Replacement	166	589	423	974
Fish Lake Unit 1 Spillway Diversion Structure	30	411	381	772
Old Crow Original Plant Rebuild	50	249	199	714
Generation < \$20,000	(553)	29	582	
All Other Projects	1,270	1,251	(19)	
Total	963	2,529	1,566	

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Continuity of Capital Expenditures
(\$000)

Line No.	Project Name	Business Case	Actuals		Approved		Variance		
			2016	2017	2016	2017	\$	%	
1	Generation								
2	Fish Lake 2 Head Pond Spillway Replacement		286	166	20	589	157	35%	Delayed to 2018 due to Fish Lake Ditch 1 Failure as well as digging and water level conditions. Unanticipated event that required immediate remediation. 2017 includes \$150K credit for insurance proceeds. Please see Business Case #02 for further details.
3	Fish Lake Ditch 1 Failure	#02	412	(150)	-	-	(262)	-100%	
4	Fish Lake Ditch 1 Intake Building - Design		2	1	-	30	27	930%	
5	Fish Lake Unit 1 Spillway Diversion Structure		-	30	-	411	381	1262%	Delayed to 2019 and 2020 due to Fish Lake Ditch 1 Failure as well as digging and water level conditions.
6	Fish Lake Unit 2 Assessment		98	11	100	-	(9)	-8%	
7	Fish Lake Water Monitoring Upgrades		10	106	25	25	(66)	-57%	Higher than approved due to Fish Lake Ditch 1 Failure and changes in requirements.
8	Fish Lake Unit 1 Turbine and Building Replacement		20	16	-	-	(35)	-100%	
9	Fish Lake Ditch 3 Diversion Replacement		2,601	168	2,908	-	139	5%	
10	Louise Lake Containment Dyke Seismic Analysis		-	-	40	-	40	100%	
11	Watson Lake Plant Fire Alarm System - Design		-	-	-	102	102	100%	The costs related to the project design were captured in the Watson Lake Plant Fire alarm project in line 12 below and were lower than expected.
12	Watson Lake Plant Fire Alarm System		-	62	-	-	(62)	-100%	Higher than approved due to costs related to project design being included in this line item (\$7K) as well as project work being advanced from future years.
13	Watson Lake Plant PLC		-	28	-	-	(28)	-100%	
14	Watson Lake Unit 5 PLC		-	22	-	-	(22)	-100%	
15	Watson Lake Unit 2 Replacement		1,054	270	1,387	-	63	5%	
16	Old Crow Unit 2 Generator Refurbishment		39	-	75	-	36	92%	
	Old Crow Original Plant Rebuild								
17	Old Crow Unit 3 Replacement	#41	369	50	-	249	(170)	-41%	Higher than approved due to unexpected costs required to reinforce the floor of the facility. 2018 includes a \$118K credit for settlement costs from the Engineering firm hired to design the new plant due to the failure of the floor system design. Costs related to the original plant rebuild were incurred from 2018 through 2022.
18	Old Crow Unit 3 Replacement		1,085	8	1,046	-	(47)	-4%	
19	Old Crow Unit 2 - External Equipment		-	-	-	51	51	100%	Lower than approved due to work on project being halted based on plant conditions. Awaiting new plant construction.
20	Destruction Bay Unit 1 Major Overhaul	#23	133	7	-	-	(140)	-100%	Units require an overhaul after 24,000 hours of runtime, which occurred earlier than anticipated for Destruction Bay Unit 1. Please see Business Case #23 for further details.
21	Destruction Bay Unit 3 Replacement		5	28	-	-	(34)	-100%	
22	Destruction Bay Programmable Logic Controller Upgrade		15	252	-	305	38	14%	
23	Destruction Bay Unit 2 Replacement		538	9	620	-	74	13%	Lower than approved due to shared savings of other work being completed on site PLC replacement line 22.
24	Destruction Bay Fuel Line Upgrade		55	-	106	-	51	94%	Lower than approved due to forecast including costs for potential Utilidor and plant modifications which were not required during construction.
25	Pelly Crossing Fuel System Upgrade		-	143	-	152	9	6%	
26	Pelly Crossing Ventilation System Upgrade		-	-	-	25	25	100%	
27	Pelly Crossing Unit 2 Silencer		-	-	-	20	20	100%	
28	Ross River Replace ABB 5HK Breakers		71	-	95	-	24	33%	
29	Ross River Electrical Service Panel Upgrade		-	-	25	-	25	100%	
30	Swift River Unit 1 Replacement		36	82	80	61	22	19%	
31	Teslin Plant Assessment		-	13	-	102	89	710%	Lower than approved due to project scope being reduced to only assess pad and foundation.
32	Teslin PLC Replacement - Design		-	41	-	105	64	155%	Lower than approved due to project scope being increased to include long lead equipment purchase.
33	Haines Junction Fuel Containment Upgrade		-	-	-	30	30	100%	
34	PLC Replacement Stage 1		-	76	-	103	27	36%	
35	2017 Gen Failed Hardware Contingency		-	27	-	-	(27)	-100%	
36	Mobile Generator 250kW Voltage and Frequency Protection		7	0	35	-	28	382%	
37	Mobile Generator 225 kW Refurbishment		6	10	20	-	4	26%	
38	Mobile Generator 350 kW Refurbish Enclosure		-	38	-	19	(19)	-50%	
39	Fuel System Assessment		-	-	-	99	99	100%	Work was complete in 2017, but due to the scope of work, it was determined that the expenses should be classified as O&M instead of capital.
40	IRC Chargers		-	-	-	22	22	100%	
41	Generation < \$20,000		102	(553)	20	29	500	-111%	Lower than approved due to cancelled project write-offs, including a \$443K write-off of for Watson Lake LNG per Board Order 2017-03 in 2017.
42									
43	Generation Total		6,944	963	6,602	2,529	(1,224)		

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AEY-YUB-046

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-046

Reference: 2023-24 GRA, Section 9, PDF page 174; Schedule 9.2

Issue: Capital Expenditures – Generation

Quote: To support this capital spend, AEY has provided Business Cases related to capital expenditures as follows: Business Cases are provided for 2016-17 where variances from actual to approved were both greater than 100 percent and greater than \$100,000; Business Cases are provided for capital expenditures in 2018-2022 that exceeded \$100,000; Business Cases are provided for projects planned to be undertaken in 2023-24 where capital expenditures are forecast to be \$500,000 or greater; and Business Cases are provided for significant upcoming projects where certain un-capitalized costs are forecast in the Test Period but capitalized expenditures are forecast subsequent to the Test Period.

Preamble: The Board requires a cross-reference between the projects listed in Schedule 9.2 and the business cases provided by AEY.

Request:

- (a) Please insert an additional column in Schedule 9.2 providing the business case reference to each of the line items in that schedule.
- (b) Please provide a business case regarding all Old Crow plant work (Schedule 9.2 lines 56-69), the Louise Lake Auxiliary Structure Replacement (Schedule 9.2 line 110) and Fish Lake projects (Schedule 9.2 - lines 2-24).

Response:

- (a) Please refer to AEY-YUB-046(a) Attachment 1.
- (b) AEY notes that not all the Old Crow and Fish Lake generation project line items on Schedule 9.2 lend themselves to a single overarching business case, as there are

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many different drivers for the expenditures such as load growth, end of life equipment and emergency repairs. AEY has provided a detailed project description of all of the line items on Schedule 9.2 that are not included in the Business Cases and has included the references to the Business Cases where applicable.

- Old Crow plant work please refer to AEY-YUB-046(b) Attachment 1.
- Fish Lake projects please refer to AEY-YUB-046(b) Attachment 2.

For the Louise Lake Auxiliary Structure Replacement, please refer to Business Case #33.

ATCO Electric Yukon (AEY)
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Continuity of Capital Expenditures
(\$000)

Line No.	Project Name	Business Case	Actuals							Test Period		Approved	
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
1	Generation												
2	Fish Lake Unit 2 - Replace Power Station - Detailed D	Business Case No. 39	-	-	-	-	-	-	-	-	527	-	-
3	Fish Lake 1 Roof Replacement	Business Case No. 32	-	-	-	-	-	-	-	452	-	-	-
4	Fish Lake 2 Replace Power Station FEED	Business Case No. 39	-	-	-	-	-	-	-	385	-	-	-
5	Fish Lake 2 Head pond Intake Building Replacement		-	-	-	-	-	-	-	153	-	-	-
6	Fish Lake 2 Head Pond Spillway Replacement		286	166	540	(17)	-	-	-	-	-	20	589
7	Fish Lake Ditch 1 Failure	Business Case No. 02	412	(150)	-	-	-	-	-	-	-	-	-
8	Fish Lake Ditch 1 Intake Building - Design		2	1	115	(26)	11	-	-	-	-	-	30
9	Fish Lake Unit 1 Spillway Diversion Structure		-	30	0	220	527	(5)	-	-	-	-	411
10	Fish Lake Unit 2 Assessment		98	11	(112)	-	-	-	-	35	-	100	-
11	Fish Lake Unit 2 Condition Assessment and Options Analysis		-	-	-	-	-	-	66	-	-	-	-
12	Fish Lake 2 TIV actuator and wicket gates		-	-	-	-	-	-	-	37	-	-	-
13	Fish Lake Unit 1 Roof Design	Business Case No. 32	-	-	-	-	-	43	16	-	-	-	-
14	Fish Lake Unit 2 Bearing and Shaft Repair		-	-	-	48	6	-	-	-	-	-	-
15	Fish Lake Unit 2 TIV Replace		-	-	48	(1)	-	-	-	-	-	-	-
16	Fish Lake 1 Add TIV Actuator		-	-	-	-	-	-	-	-	53	-	-
17	Fish Lake 1 TIV replacement		-	-	-	-	-	-	24	89	-	-	-
18	Fish Lake 2 Add bypass valve actuator and automation		-	-	-	-	-	-	-	35	-	-	-
19	Fish Lake 2 PLC Replacement		-	-	-	-	-	-	-	-	39	-	-
20	Fish Lake Unit 2 DC TIV Actuator & Wicket Gate Replacement		-	-	-	-	-	-	138	-	-	-	-
21	Fish Lake Water Monitoring Upgrades		10	106	1	24	(0)	(0)	-	26	81	25	25
22	Fish Lake Unit 1 Turbine and Building Replacement		20	16	16	3	4	3	(71)	-	-	-	-
23	Fish Lake Ditch 3 Diversion Replacement		2,601	168	30	0	-	29	(27)	-	-	2,908	-
24	Louise Lake Containment Dyke Seismic Analysis		-	-	-	-	-	-	-	-	-	40	-
25													
26	Watson Lake - Replace Air Start Piping		-	-	-	-	-	-	-	103	-	-	-
27	Watson Lake Add Building Concrete Apron		-	-	-	-	-	-	-	25	-	-	-
28	Watson Lake block heater pumps		-	-	-	-	-	-	-	50	-	-	-
29	Watson Lake Expansion Tank and Access Replacement Design		-	-	-	-	-	-	25	152	-	-	-
30	Watson Lake Fuel Piping Upgrade		-	-	-	-	-	-	-	231	-	-	-
31	Watson Lake Fuel System Control Replacement		-	-	-	-	-	-	-	136	-	-	-
32	Watson Lake Install Diverter Actuator, with limit switches, for #1/6 boilers		-	-	-	-	-	-	-	25	-	-	-
33	Watson Lake Replace HRS pumps/motors		-	-	-	-	-	-	-	100	-	-	-
34	Watson Lake Replace Non-Code Exchangers for #2/4		-	-	-	-	-	-	-	100	-	-	-
35	Watson Lake Unit 1 Replacement	Business Case No. 07	-	-	-	418	1,278	130	-	-	-	-	-
36	Watson Lake Unit 2 - Major Overhaul	Business Case No. 23	-	-	-	-	-	-	-	375	-	-	-
37	Watson Lake Unit 3 Replacement	Business Case No. 07	-	-	436	1,213	241	-	-	-	-	-	-
38	Watson Lake Unit 4 - Major Overhaul	Business Case No. 23	-	-	371	(2)	-	-	-	-	515	-	-
39	Watson Lake Unit 4 EMCP Replacement	Business Case No. 08	-	-	-	-	-	177	(26)	-	-	-	-
40	Watson Lake Unit 5 Major Overhaul	Business Case No. 23	-	-	-	-	-	-	438	41	-	-	-
41	Watson Lake Unit 6 Replacement	Business Case No. 07	-	-	-	-	828	901	140	-	-	-	-
42	Watson Lake Waste Heat Cathodic Protection		-	-	-	-	-	-	-	150	-	-	-
43	Watson Lake 125VDC Battery and Charger Replacement		-	-	-	23	-	-	-	-	-	-	-
44	Watson Lake Fuel Tank Access		-	-	17	128	-	-	-	-	-	-	-
45	Watson Lake Inverter Replacement		-	-	-	51	-	-	-	-	-	-	-
46	Watson Lake Plant Fire Alarm System - Design		-	-	-	-	-	-	-	-	-	-	102
47	Watson Lake Plant Fire Alarm System		-	62	106	(2)	-	-	-	-	-	-	-
48	Watson Lake Plant Fuel Sys Control Replace		-	-	-	-	-	1	147	-	-	-	-
49	Watson Lake Plant Overhead Door Replacement		-	-	-	-	-	-	24	-	-	-	-
50	Watson Lake Plant Phone System Replacement		-	-	-	34	(1)	-	-	-	-	-	-
51	Watson Lake Plant PLC		-	28	1	-	-	-	-	-	-	-	-
52	Watson Lake Unit 5 PLC		-	22	1	-	-	-	-	-	-	-	-
53	Watson Lake Utilidor Split/Fuel Sys		-	-	42	6	4	2	3	-	-	-	-
54	Watson Lake Unit 2 Replacement		1,054	270	-	-	-	-	-	-	-	1,387	-
55													
56	Old Crow Add Day Tank and Fuel Transfer Pump		-	-	-	-	-	-	-	25	103	-	-
57	Old Crow Boiler Metering and Control		-	-	-	-	-	-	-	25	-	-	-
58	Old Crow Plant Tank Access		-	-	-	-	-	-	-	-	232	-	-
59	Old Crow Unit 1 Major Overhaul YTCU414	Business Case No. 23	-	-	-	-	475	(10)	-	-	-	-	-
60	Old Crow Unit 2 Replacement		-	-	-	192	(17)	-	-	-	-	-	-
61	Old Crow Unit 3 Failure - Major Overhaul		-	-	-	-	-	270	(190)	-	-	-	-
62	Old Crow Unit 4 Major Overhaul	Business Case No. 23	-	-	-	-	-	-	252	-	-	-	-
63	Old Crow # 2 Long Block Replacement	Business Case No. 23	-	-	-	-	-	-	71	-	-	-	-
64	Old Crow Unit 2 Generator Refurbishment		39	-	-	-	-	-	-	-	-	75	-
65	Old Crow Old Plant Gantry Accessories		-	-	-	-	23	(2)	-	-	-	-	-

ATCO Electric Yukon (AEY)
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Continuity of Capital Expenditures
(\$000)

No.	Project Name	Business Case	Actuals						Test Period		Approved		
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
66	Old Crow Plant (old) Gantry Crane		-	-	-	-	22	-	-	-	-	-	-
67	Old Crow Original Plant Rebuild	Business Case No. 41	369	50	(118)	2	6	489	(85)	150	-	-	249
68	Old Crow Unit 3 Replacement		1,085	8	-	-	-	-	-	-	-	1,046	-
69	Old Crow Unit 2 - External Equipment		-	-	-	-	-	-	-	-	-	-	51
70													
71	Beaver Creek Unit 3 Major Overhaul	Business Case No. 23	-	-	-	-	-	323	(6)	-	-	-	-
72	Beaver Creek Replace JW and CAC cooler		-	-	-	-	-	-	-	100	-	-	-
73	Beaver Creek Station Service Transformer		-	-	-	-	-	-	-	100	-	-	-
74	Beaver Creek Unit 1 Major Overhaul	Business Case No. 23	-	-	-	-	-	307	(132)	-	-	-	-
75	Beaver Creek Unit 2 Major	Business Case No. 23	-	-	127	(1)	-	-	-	-	-	-	-
76	Beaver Creek Utilidor Upgrades		-	-	-	-	-	-	-	20	-	-	-
77	Destruction Bay/ Stewart/ Beaver Creek Plant Conditio	Business Case No. 40	-	-	-	-	-	-	-	318	-	-	-
78													
79	Destruction Bay Unit 2 Major Overhaul	Business Case No. 23	-	-	-	-	-	181	(7)	-	-	-	-
80	Destruction Bay Unit 1 Major Overhaul	Business Case No. 23	133	7	-	-	-	-	-	-	-	-	-
81	Destruction Bay Unit 3 Replacement		5	28	-	-	-	-	-	-	-	-	-
82	Destruction Bay Programmable Logic Controller Upgrade		15	252	13	-	-	-	-	-	-	-	305
83	Destruction Bay Unit 2 Replacement		538	9	-	-	-	-	-	-	-	620	-
84	Destruction Bay Fuel Line Upgrade		55	-	-	-	-	-	-	-	-	106	-
85	Destruction Bay Unit 3 Major Overhaul	Business Case No. 23	-	-	-	-	-	112	(16)	-	-	-	-
86	Destruction Bay Replace POW	Business Case No. 40	-	-	-	-	-	-	-	-	309	-	-
87													
88	Pelly Crossing Fuel System Upgrade		-	143	119	(4)	-	-	-	-	-	-	152
89	Pelly Crossing Ventilation System Upgrade		-	-	-	-	-	-	-	-	-	-	25
90	Pelly Crossing Unit 2 Silencer		-	-	-	-	-	-	-	-	-	-	20
91													
92	Ross River Replace ABB 5HK Breakers		71	-	-	-	-	-	-	-	-	95	-
93	Ross River Electrical Service Panel Upgrade		-	-	-	-	-	-	-	-	-	25	-
94													
95	Swift River Unit 2 Replacement	Business Case No. 21	-	-	-	-	-	-	225	2	-	-	-
96	Swift River Unit 1 Replacement		36	82	4	-	-	-	-	-	-	80	61
97	Swift River Fuel System Upgrade		-	-	-	38	-	-	-	-	-	-	-
98	Swift River Unit 1 PLC Replacement		-	-	-	23	-	-	-	-	-	-	-
99	Swift River Unit 2 Replace		-	-	-	-	52	8	-	-	-	-	-
100													
101	Teslin Plant Assessment		-	13	(14)	1	-	-	-	-	-	-	102
102	Teslin PLC Replacement - Design		-	41	387	(1)	-	-	-	-	-	-	105
103	Teslin Plant Platform Replacement		-	-	-	34	(0)	-	-	-	-	-	-
104	Teslin Rad Core Replacement		-	-	-	-	22	-	-	-	-	-	-
105													
106	Haines Junction Fuel Containment Upgrade		-	-	-	-	-	-	-	-	-	-	30
107	Haines Junction Plant Positive Air Shutoff for YTCU416		-	-	-	-	-	20	3	-	-	-	-
108	Haines Junction Regulator Pad Replacement		-	-	-	-	-	4	36	-	-	-	-
109													
110	Louise Lake Auxiliary Structure Replacement	Business Case No. 33	-	-	-	11	31	8	2	1	773	-	-
111													
112	IPP Remote monitoring		-	-	-	-	-	-	-	100	-	-	-
113	Carmacks Plant Foundation Repair		-	-	-	14	16	-	-	-	-	-	-
114	Mobile CUL-341 PLC replacement		-	-	-	-	-	-	-	-	94	-	-
115	Pelly Unit 3 Block Replacement	Business Case No. 23	-	-	-	111	(1)	-	-	-	-	-	-
116	PLC Replacement Stage 1		-	76	(3)	(1)	-	-	-	-	-	-	103
117	Replace fuel ESD valve within utilidor (x10)		-	-	-	-	-	-	-	-	52	-	-
118	2017 Gen Failed Hardware Contingency		-	27	(1)	(2)	-	-	-	-	-	-	-
119	Mobile Generator 250kW Voltage and Frequency Protection		7	0	-	-	-	-	-	-	-	35	-
120	Mobile Generator 225 kW Refurbishment		6	10	-	-	-	-	-	-	-	20	-
121	Mobile Generator 350 kW Refurbish Enclosure		-	38	2	-	-	-	-	-	-	-	19
122	Standby plant equipment and building heat		-	-	-	-	-	-	-	-	52	-	-
123	Add transfer trip scheme		-	-	-	-	-	-	-	100	-	-	-
124	Fish Creek Diversion		-	-	-	-	-	-	-	-	317	-	-
125	General Plant Improvements		-	-	-	-	-	-	-	-	155	-	-
126	Fuel System Assessment		-	-	-	-	-	-	-	-	-	-	99
127	IRC Chargers		-	-	-	-	-	-	-	-	-	-	22
128													
129	Generation < \$20,000		102	(553)	19	96	70	59	127	82	52	20	29
130													
131	Generation Total		6,944	963	2,147	2,635	3,597	3,050	1,178	3,723	3,352	6,602	2,529

No.	Project Name	Business Case	Actuals							Test Period		Approved	
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
132													
133	Kluane First Nation Wind Turbine Upgrades	Business Case No. 37	-	-	-	-	12	17	1,210	2,215	750	-	-
134	Renewables - Old Crow		-	-	-	1,034	1,147	1,406	34	-	-	-	-
135	Watson Lk IPP - Integration to Plant		-	-	-	-	-	18	6	75	-	-	-
136	Beaver Creek PV Generation	Business Case No. 38	-	-	-	-	-	64	2,500	3,767	1,686	-	-
137	Study Costs			208	80	(27)	(72)	(175)	(1)	(13)	-	-	-
138	Renewables Total		-	208	80	1,007	1,087	1,330	3,749	6,044	2,436	-	-
139													
140													
141	New Extensions												
142	New Services Overhead and Underground	Business Case No. 18	1,747	1,600	2,555	2,701	2,446	3,846	2,777	4,219	4,324	1,995	2,032
143	Annual Land Rights		116	84	66	89	81	69	67	102	82	120	122
144	General Drafting and Mapping		37	35	53	42	52	49	45	46	41	40	41
145													
146	Whistle Bend Stage 3	Business Case No. 31	215	690	545	479	(20)	-	-	-	-	-	1,173
147	Whistle Bend Stage 4	Business Case No. 31	-	476	729	717	(12)	-	-	-	-	-	-
148	Whistle Bend Stage 5	Business Case No. 31	-	-	(17)	745	216	-	-	-	-	-	-
149	Whistle Bend Stage 6	Business Case No. 31	-	-	-	-	433	-	-	285	-	-	-
150	Whistle Bend Stage 7	Business Case No. 31	-	-	-	-	9	0	351	460	-	-	-
151	Whistle Bend Stage 8	Business Case No. 31	-	-	-	-	-	-	140	18	-	-	-
152	Whistle Bend Stage 9	Business Case No. 31	-	-	-	-	-	-	-	683	458	-	-
153	Whistle Bend future stages - place holder	Business Case No. 31	-	-	-	-	-	-	-	-	309	-	-
154	Whistle Bend New Services		-	-	-	-	136	-	234	-	-	-	-
155													
156	Mt Sima Pumphouse		-	-	-	-	123	141	-	-	-	-	-
157	Brookside Phase 2B		-	112	59	25	-	-	-	-	-	-	-
158	Challenge Development 704 Main Street		-	-	-	-	135	0	-	-	-	-	-
159	Hammerstone Lots off Tlingit Street		-	-	-	-	37	27	125	-	-	-	-
160	Loft 2240 2nd Avenue		-	-	-	-	-	133	-	-	-	-	-
161	Mt Sima Hill Service		-	-	-	-	-	-	413	-	-	-	-
162	Schmidt, Harold & Savanah		-	-	-	119	(0)	-	-	-	-	-	-
163	TSL/Ketza Old Crow Health & Housing		-	-	-	-	-	163	-	-	-	-	-
164	VGFN Houses on North Rd		250	-	-	-	-	-	-	-	-	-	-
165	VoT Connector Road Subdivision		-	-	-	145	(1)	-	-	-	-	-	-
166													
167	YG Airport Hangar		-	-	-	-	-	-	562	(30)	-	-	-
168	Yukon Lot 503		-	-	-	113	-	-	-	-	-	-	-
169													
170	New Extension < \$20,000		-	-	-	-	-	-	-	102	-	-	(1)
171	New Extensions Total		2,365	2,997	3,990	5,176	3,636	4,428	4,714	5,885	5,215	2,155	3,367
172													
173													
174	New Extensions-IPP												
175	Arctic Pharm IPP	Business Case No. 35	-	-	-	-	-	-	-	543	-	-	-
176	Sunergy YEC HJ IPP		-	-	-	-	-	-	-	343	-	-	-
177	Haeckel Hill	Business Case No. 36	-	-	-	-	-	-	1,219	235	-	-	-
178	THELP		-	-	-	-	-	185	175	(7)	-	-	-
179	New Extensions - IPP Total		-	-	-	-	-	185	1,394	1,115	-	-	-
180													
181	Distribution Improvements												
182	Annual Right of Way Widening	Business Case No. 12&26	494	581	292	489	434	481	555	520	528	439	447
183	General Pole Replacements		40	35	39	29	112	97	98	254	211	297	284
184	PCB Identification and Transformer Change Outs		137	14	-	-	-	-	-	-	-	150	51
185	Vault Replacements		27	44	0	117	(15)	(4)	10	51	-	40	102
186	General Clearance Upgrades/Fixes		11	-	5	3	9	33	37	84	108	50	51
187	Test and Treat Pole Program		-	-	-	45	25	70	117	21	22	-	-
188	Gang Switch Replacement		53	29	11	36	19	1	20	-	-	-	-
189	T&B Switch Change Out		17	2	20	36	32	34	16	119	64	-	-
190													
191	McIntyre Subdivision Rebuild	Business Case No. 01	748	1,035	405	141	(91)	1,368	285	109	1,244	564	924
192	Downtown Whitehorse Capacity Upgrade		1,299	507	-	-	-	-	-	-	-	1,451	366
193	Hillcrest Subdivision Conversion		(5)	41	-	-	-	-	-	-	-	-	152
194													
195	Upgrade Underground Line Into Services and Shipyard Sub		-	-	-	-	-	-	-	-	-	102	-
196	McCrae Substation Second Feeder Breaker		608	133	-	-	-	-	-	-	-	414	-
197	McCrae Substation Transformer Upgrade to 10 MVA		251	-	-	-	-	-	-	-	-	297	-

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No.	Project Name	Business	Actuals						Test Period		Approved		
		Case	2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
198	Whistle Bend Way Underground Crossing		230	94	-	-	-	-	-	-	-	60	-
199	Upper Liard – Replace Liard River Crossing		27	-	-	-	-	-	-	-	-	-	-
200	AEY 34.5kV Cable Replacement		152	0	-	-	-	-	-	-	-	-	-
201	Fault Indicators in Padmount Equipment		49	1	-	-	-	-	-	-	-	50	-
202	AEY Maintenance Work Request 241-2016 HJ Reg		23	-	-	-	-	-	-	-	-	-	-
203	AEY 2016 Safety Audit F		22	-	-	-	-	-	-	-	-	-	-
204	AEY Cable Testing 2016		20	-	-	-	-	-	-	-	-	-	-
205	AEY Maintenance Work Request M97-2013 Pole Change		2	26	0	-	-	-	-	-	-	-	-
206	AEY 102 Lambert Encroachment		2	3	2	18	1	2	1	-	-	-	-
207	AEY Trespass L1131 Car		1	67	-	-	-	-	-	-	-	-	-
208	5L622 - Lewes River Bridge Crossing Replacement		1	87	-	-	-	-	-	-	-	140	-
209	Paint Mountain Conductor Replacement		(4)	144	72	306	37	177	(34)	-	-	-	559
210	Range Road Rebuild		108	-	-	-	-	-	-	-	-	110	-
211	Carcross Nares Bridge Relocation		-	-	-	-	-	-	-	-	-	90	-
212													
213	Replace Watson Lake Substation Transformer T2		-	175	67	(7)	0	-	-	-	-	-	356
214	400 Amp Regulators in Logan Substation	Business Case No. 03	-	168	6	-	-	-	-	-	-	-	122
215	AEY Carcross Corner Pol		-	41	1	-	-	-	-	-	-	-	-
216	AEY Maintenance Work Order M255-2016 3rd a		-	28	-	-	-	-	-	-	-	-	-
217	AEY CCC Rd Rebuild		-	9	174	0	-	-	-	-	-	-	-
218	3 Phase Hotsprings Rd	Business Case No. 05	-	-	-	386	11	(4)	-	-	-	-	-
219	Haines Junction OSS Replacement		-	47	21	(16)	-	-	-	-	-	-	51
220	Single Regulator 5L631		-	25	-	-	-	-	-	-	-	-	30
221	Steward Crossing Ferry Hill Line Rebuild - Design		0	16	2	1	1	(21)	-	-	-	-	30
222	McRae Substation Regulator Upgrade		-	-	-	-	-	-	-	-	-	-	20
223	Rebuild Line Behind City Municipal Services Building		-	-	-	-	-	-	-	-	-	-	81
224													
225													
226	Distribution Improvements Continued												
227	AEY Old Crow Volt Issues-Loop		-	-	356	6	-	-	-	-	-	-	-
228	AEY 25kV A.Hwy Hamilton Tie		-	-	218	(12)	(14)	-	-	-	-	-	-
229	McIntyre Subdivision Contingency Loop	Business Case No. 11	-	-	116	189	(0)	(10)	-	-	-	-	-
230	Teslin Substn Metering		-	-	61	(1)	-	-	-	-	-	-	-
231	Teslin OSS Replacement		-	-	47	(0)	-	-	-	-	-	-	-
232	AEY 3rd Ave Burial Dwntrwn		-	-	42	3	6	2	2	-	-	-	-
233	AEY Wtsn Lk Vertical Strcts		-	-	28	0	-	-	-	-	-	-	-
234	AEY Teslin Sub Gnd Grid		-	-	18	7	6	0	-	-	-	-	-
235	AEY Lower Post Fire 2018		-	-	16	24	-	-	-	-	-	-	-
236	AEY Cowley Rd Rebuild SKH		-	-	7	85	18	-	-	-	-	-	-
237	AEY 2nd Ave Trespass		-	-	3	2	18	-	-	-	-	-	-
238	AEY SCADA Swtch at Pinerdg		-	-	1	42	2	25	6	-	-	-	-
239	YG Toyota Access, Intersection & Frontage Road Upgrades		-	-	0	341	2	-	-	-	-	-	-
240	AEY YG Nares River Bridge		4	82	(13)	(7)	-	-	-	-	-	-	-
241	Whitehorse Airport Hanger D Area Rebuild		0	12	1	160	(9)	-	-	-	-	-	142
242													
243	AEY Reroute Mountain View		-	-	-	53	0	-	-	-	-	-	-
244	AEY Aerial Trespass Lot 9 Blk 16 Adela Trail Watson Lake		-	-	-	0	1	116	37	-	-	-	-
245	Rogers Street 25kV Conversion		-	-	-	24	16	-	-	-	-	-	-
246	AEY Trespass Primary Line Reroute, Lot 1499 Hotsprings Road		-	-	-	1	21	24	-	-	-	-	-
247	Install 35kV Regulators on Carcross Road	Business Case No. 17	-	-	-	-	199	(3)	-	-	-	-	-
248	HLC Breaker Replacement	Business Case No. 04	-	-	-	-	136	-	-	-	-	-	-
249	Upgrade Regulators at Laberge Substation	Business Case No. 09	-	-	-	-	129	-	-	-	-	-	-
250	Powerline Relocation Hillcrest YG Highway Realignme	Business Case No. 15	-	-	-	-	119	5	(3)	-	-	-	-
251	Reconductor Mayo Rd Mainline	Business Case No. 06	-	-	-	-	111	-	-	-	-	-	-
252	Shipyards Sub Replace Relays		-	-	-	-	94	-	-	-	-	-	-
253	266 ACSR Upgrade Sumanik Drive		-	-	-	-	73	-	-	-	-	-	-
254	AEY Aerial Trespass Lots 14A & 14B Pilot Mtn Sub'd		-	-	-	-	37	-	-	-	-	-	-
255	AEY D/C Powerline Reroute Cousins to Mayo Cutoff		-	-	-	-	35	(7)	-	-	-	-	-
256	Riverdale Load Sectionalizing		-	-	-	-	25	-	-	-	-	-	-
257	DWCI- Downtown South Voltage Conversion- prep		-	-	-	-	17	18	2	-	-	-	-
258	AEY Reconductor Mayo Road Mainline - Stage 2	Business Case No. 06	-	-	-	-	15	138	-	-	-	-	-
259	AEY Powerline Relocation YG Alaska Hwy Crestview I	Business Case No. 15	-	-	-	-	0	225	(41)	-	-	-	-
260													
261	Powerline Relocation Burns Road to Range Road Inter	Business Case No. 15	-	-	-	-	-	136	(18)	-	-	-	-
262	AEY Hamilton to Alaska Highway 25kV Tie		-	-	-	-	-	73	(4)	-	-	-	-
263	AEY Powerline Relocation Lot 2 Salvation Army		-	-	-	-	-	62	2	-	-	-	-

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No.	Project Name	Business Case	Actuals						Test Period		Approved		
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
264	Upgrade Recloser at Carx Substn		-	-	-	-	-	44	-	-	-	-	-
265	AIS 9 Switch Cube Replacement - S2350 Hamilton Blvd		-	-	-	-	-	37	0	-	-	-	-
266	AEY New Subst Mayo Rd		-	-	-	-	-	29	-	-	-	-	-
267	AEY Voltage Issues Gold Road		-	-	-	-	-	3	28	-	-	-	-
268													
269	AEY Aerial Trespass Lot 23, Blk 25 or 102 Teslin Crescent, (Thomas Slager), Watson La		-	-	-	-	-	-	47	-	-	-	-
270	Ross River Substn Voltage Regulator Control		-	-	-	-	-	-	36	-	-	-	-
271	Upgrade Recloser Mountainview Substn		-	-	-	-	-	-	54	-	-	-	-
272	New Substation Mayo Road	Business Case No. 25	-	-	-	-	-	-	400	2,400	-	-	-
273	Reconductor Mayo Rd Mainline - Stage 3	Business Case No. 06	-	-	-	-	-	0	162	-	-	-	-
274	Watson Lake Substation Feeder & Feeder Protection Replacement		-	-	-	-	-	-	146	66	-	-	-
275													
276	Downtown south voltage conversion		-	-	-	-	-	-	-	-	-	-	-
277	AEY Choutla Long Span Rebuild		-	-	-	-	-	-	-	40	-	-	-
278	AEY Dogwood voltage improvement		-	-	-	-	-	-	-	40	-	-	-
279	AEY DWCI - New 12.5kV substation		-	-	-	-	-	-	-	25	792	-	-
280	AEY Haines Junction Regulator Stand Replacement		-	-	-	-	-	-	-	20	-	-	-
281	AEY New Substation Whistle Bend - Leota	Business Case No. 25	-	-	-	-	-	-	-	154	2,781	-	-
282	AEY Nisutlin Bridge Pole Relocation		-	-	-	-	-	-	-	380	165	-	-
283	AEY SCADA Pineridge Switch		-	-	-	-	-	-	-	47	-	-	-
284	AEY Upgrade 6L11 conductor S150 to Carcross Corner		-	-	-	-	-	-	-	50	52	-	-
285	AEY Upgrade recloser		-	-	-	-	-	-	-	87	90	-	-
286	AEY Voltage Improvement Destruction Bay		-	-	-	-	-	-	-	225	-	-	-
287	AEY Whitehorse Escarpment line reroutes - Hoge		-	-	-	-	-	-	-	110	-	-	-
288	Robinson sub capacity		-	-	-	-	-	-	-	-	165	-	-
289	AEY Hillcrest Voltage Improvement		-	-	-	-	-	-	-	100	-	-	-
290	AEY Pelly Crossing Voltage Improvement		-	-	-	-	-	-	-	-	361	-	-
291	Watson Lake 5L621 Upgrade		-	-	-	-	-	-	-	-	103	-	-
292	Power System Assessment - YEC and AEY		-	-	-	-	-	-	-	150	206	-	-
293	Whitehorse CKES UG conversion		-	-	-	-	-	-	-	-	155	-	-
294	Encroachment 3rd and Black Encroachment		-	-	-	-	-	-	-	-	124	-	-
295													
296	AEY 6L19 voltage improvement	Business Case No. 30	-	-	-	-	-	-	-	-	593	-	-
297	Relocate 100 A Carcross Cutoff Regulator	Business Case No. 30									178		
298	Relocate 100 A Lewes River Regulator	Business Case No. 30									178		
299	AEY Carcross PQ monitoring		-	-	-	-	-	-	-	-	77	-	-
300	AEY Whitehorse Escarpment line reroutes - 5th avenue		-	-	-	-	-	-	-	-	412	-	-
301	Old Crow voltage improvement - reconductor	Business Case No. 29	-	-	-	-	-	-	-	-	464	-	-
302													
303	400 Amp Regulators in Arkell Substation		-	161	5	-	-	-	-	-	-	-	122
304	Shipyards Spare 25kV Breaker		-	55	146	2	-	-	-	-	-	-	102
305	Replace Underground Cables at Whitehorse Airport		0	1	1	0	(0)	0	(1)	-	-	-	84
306	Distribution Improvements < \$20,000		197	260	146	130	27	28	66	143	10	81	77
307	Distribution Improvements Total		4,516	3,921	2,318	2,634	1,658	3,180	2,028	5,195	9,081	4,335	4,153
308													
309	Street and Sentinel Lighting												
310	General Streetlight Replacements		237	211	85	166	48	105	121	342	186	199	254
311	New Customer Streetlight Installations	Business Case No. 34	170	112	230	84	850	555	180	1,060	448	199	203
312	Whistle Bend Streetlights		-	-	-	-	-	-	-	-	-	-	348
313	Watson Lake Street Light Replacement		-	-	-	-	-	-	-	-	-	-	41
314	St Lt Replacements Hart Cr.	Business Case No. 20	-	-	-	-	-	180	-	-	-	-	-
315	Car Cross Streetlights		-	429	(24)	111	(0)	-	-	-	-	-	-
316													
317	Alaska Highway North Klondike Highway Intersection		-	-	-	-	359	0	-	-	-	-	-
318	Street Lights Burns Road to Range Road Intersection		-	-	-	-	-	184	-	-	-	-	-
319	Street Lights Lodestar to Philmars Phase 1		-	-	-	-	-	-	509	-	-	-	-
320	Pelly Crossing Community Lights		-	-	-	-	-	-	145	-	-	-	-
321													
322	McIntyre Subdivision Streetlight Rebuild		-	-	-	-	-	-	-	412	155	175	254
323	YG Nisutlin Bridge Streetlights		-	-	-	-	-	-	-	110	106	-	-
324													
325	Whistle Bend 3C Street Lights		-	185	-	-	-	-	-	-	-	-	-
326	Whistle Bend Lights 4D	Business Case No. 31	-	-	-	-	159	-	-	-	-	-	-
327	Whistle Bend Street Lights - Stage 4	Business Case No. 31	-	0	261	291	-	-	-	-	-	-	-
328	Whistle Bend Street Lights - Stage 5	Business Case No. 31	-	-	-	133	211	-	-	-	-	-	-
329	Whistle Bend Street Lights - Stage 6	Business Case No. 31	-	-	-	-	-	-	-	50	-	-	-

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Line No.	Project Name	Business Case	Actuals						Test Period		Approved		
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
330	Whistle Bend Street Lights - Stage 7	Business Case No. 31	-	-	-	-	-	31	55	301	-	-	-
331	Whistle Bend Street Lights - Stage 8	Business Case No. 31	-	-	-	-	-	-	-	103	-	-	-
332	Whistle Bend Street Lights - Stage 9A	Business Case No. 31	-	-	-	-	-	-	-	186	-	-	-
333	Whistle Bend Street Lights - Stage 9B	Business Case No. 31	-	-	-	-	-	-	-	-	147	-	-
334													
335	Street and Sentinel Lighting < \$20,000		-	-	-	-	-	-	-	-	-	11	25
336	Street and Sentinel Lighting Total		407	936	553	785	1,627	1,055	1,009	2,563	1,042	584	1,125
337													
338	Meters												
339	AMI Project New Meters		-	-	-	-	-	-	-	132	304	-	-
340	Replacement of Meters and New Installations		105	88	32	67	127	75	98	103	106	199	203
341	Meters Total		105	88	32	67	127	75	98	235	410	199	203
342													
343	Transformers & Regulators												
344	General Capitalizable Transformers	Business Case No. 16	-	-	-	-	268	49	(19)	218	275	90	91
345	Spare 10 MVA Transformer		-	-	-	-	-	-	-	-	-	219	-
346	Spare Padmount Regulator for Shipyards Substation		-	-	-	-	-	-	-	-	-	58	-
347	Transformers and Regulators		73	213	70	262	118	173	10	-	-	-	-
348	AEY Old Crow Regulators	Business Case No. 29	-	-	-	-	-	-	-	710	-	-	-
349	Transformers & Regulators Total		73	213	70	262	385	222	(8)	928	275	367	91
350													
351	GP&E												
352	Computer												
353	My Account- Technology Project	Business Case No. 19	-	-	22	247	(4)	-	-	-	-	-	-
354	Computer Total		-	-	22	247	(4)	-	-	-	-	-	-
355													
356	Land & Building												
357	Service Complex Heating System		4	17	6	-	-	-	-	-	-	40	25
358	Annual Building Upgrades		-	-	-	-	-	-	-	75	73	-	-
359	Downtown Office Interior Renovations		-	-	-	-	-	-	-	51	-	-	-
360	Whitehorse Service Complex RTU'S Construction		-	-	-	-	-	-	-	100	-	-	-
361	Whitehorse Service Complex Rooftop Unit Design		-	-	-	-	-	-	-	5	-	-	-
362	Service Complex Boiler Replacement	Business Case No. 10	-	-	-	-	132	(27)	-	-	-	-	71
363	Kilowatt - Misc. Imp		24	-	-	-	-	-	-	-	-	-	-
364	102 Kilowatt Ln Refurbish		-	14	32	-	-	-	-	-	-	-	-
365	101 Kilowatt Ln Refurbish		-	19	32	-	-	-	-	-	-	-	-

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Line No.	Project Name	Business Case	Actuals						Test Period		Approved		
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
366	Warehouse Mezzanine Upg	Business Case No. 41	-	22	-	-	-	-	-	-	-	-	-
367	DT Office Renos & Improvements		-	-	-	27	-	-	-	-	-	-	-
368	Service Complex Yard Extension		-	-	-	36	0	-	-	-	-	-	-
369	Fencing for Marwell Yard		-	-	-	-	-	-	45	-	-	-	-
370	Old Crow Bunkhouse replacement		-	-	-	-	-	-	-	-	515	-	-
371	Fish Lake 1 Storage building roof replacements		-	-	-	-	-	-	-	-	77	-	-
372	Downtown Office Security and Fire Suppression		-	-	-	-	-	-	-	-	103	-	-
373	Warehousing Seacan		-	-	-	-	-	-	-	-	26	-	-
374	Furnace Replacements - Watson Lake		-	-	-	-	-	-	-	-	-	25	-
375	Watson Lake Septic Upgrade		-	-	-	-	-	-	-	-	-	-	51
376	Watson Lake Storage Solutions		-	-	-	-	-	-	-	-	-	-	92
377	Land & Buildings - Corporate < \$20,000			61	32	21	9	15	5	50	-	-	-
378	Total Land & Buildings		89	105	91	72	147	(22)	95	232	794	65	239
379													
380													
381	Communication Equipment	Business Case No. 14											
382	Communication Equipment		36	23	2	(0)	19	48	(46)	-	-	18	13
383	AEY SCADA Upgrades		26	116	30	20	10	5	20	47	141	49	66
384	Satellite Radios		-	-	-	-	-	-	157	-	-	-	-
385	Windows XP Conversion for Operations Dispatch		-	-	-	-	-	-	-	-	-	30	-
386	Form 6 Substation Controls		-	-	-	-	-	-	-	-	-	20	-
387	Whitehorse SCADA Dispatch UHF Repeater		-	-	-	-	-	-	-	-	-	36	
388													
389	Total Communication Equipment		63	138	32	20	29	53	131	47	141	117	115
390													
391	Tools, Instruments & Equip.												
392	FRC Replacement		19	24	9	18	13	10	8	22	25	-	-
393	Power Quality Meter		-	-	-	-	-	-	14	20	-	-	-
394	Primary current monitors		-	-	-	-	-	-	-	26	27	-	-
395	Miscellaneous Tools and Instruments		132	138	64	180	95	150	65	242	76	149	165
396	Total Tools, Instruments & Equip.		151	162	73	197	108	160	87	310	128	149	165
397													
398	Office Computer Equipment												
399	Office Furniture & Equipment		20	11	2	5	5	12	14	62	20	20	20
400	2021 Surface Pro Purchases		-	-	-	-	-	21	-	-	-	-	-
401	Replace XP Operating Systems - iFix PCs		31	0	-	-	-	-	-	-	-	-	46
402													
403	GP&E Continued	Business Case No. 22											
404	CIS Replacement		-	-	-	-	-	680	3,712	3,666	345	-	-
405	Asset Management - Evaluation & Program Roadmap	Business Case No. 24	-	-	-	-	-	-	59	13	-	-	-
406	Asset Management - Phase 1		-	-	-	-	-	-	-	305	901	-	-
407	Sales force		-	-	-	-	-	-	-	172	155	-	-
408	My Account Enhancements - AEY		-	-	-	-	-	37	16	-	-	-	-
409	Enterprise Batch Printing		-	-	-	-	-	-	49	-	-	-	-
410	Fleet Maximo - AEY		-	-	24	29	7	-	-	-	-	-	-
411	Oracle R12 Replacement		-	51	51	-	-	-	-	-	-	-	-
412													
413	Office Computer Equipment < \$20,000		2	16	3	10	21	4	(71)	43	13	-	-
414	Total Office Computer Equipment		54	79	79	44	32	755	3,780	4,261	1,434	20	66
415													
416	Transportation Equipment	Business Case No. 27&28											
417	Transportation Equipment		18	51	6	88	117	507	397	697	766	369	315
418	Purchase New Unit YT169 - Small Bucket Truck	Business Case No. 13						264					
419	Unit 136 to Replace Unit 643 Bucket Truck			614									
420	Unit YT144 New Mechanic's Truck	Business Case No. 13	-	-	-	145	-	-	-	-	-	-	-
421	Purchase Unit YT145 to Replace Unit 091	Business Case No. 13	-	-	-	149	-	-	-	-	-	-	-
422	Unit 151 Digger to Replace Unit 429 - WLk Bucket	Business Case No. 13	-	-	-	-	324	11	-	-	-	-	-
423	Purchase Unit YT148 - Replace Unit 092 - Ram 5500 (	Business Case No. 13	-	-	-	-	129	-	-	-	-	-	-
424	Purchase YT159 - Replace Unit 886 - 1 Ton Service B	Business Case No. 13	-	-	-	-	-	158	-	-	-	-	-
425	Total Transpiration Equipment		18	665	6	382	570	675	661	697	766	369	315
426			-	-	-	-	-	-	-	-	-	-	-
427	Other Projects Less Than \$20,000											37	102
428	GP&E Total		374	1,150	303	962	883	1,621	4,753	5,547	3,263	757	1,002
429	Grand Total		14,784	10,476	9,491	13,529	13,001	15,147	18,914	31,234	25,073	14,999	12,470



2023-2024 General Rate Application

Old Crow Generation Capital Expenditure Information

OLD CROW GENERATION	\$3,517,000
Old Crow Add Day Tank and Fuel Transfer Pump Old Crow #3 and #4 and the boiler suffer from fuel starvation / priming issues, due to the elevation of the new plant and the existing fuel storage tanks. A day tank and pump, designed to meet National Fire Code requirements, will be installed to alleviate these operational problems.	\$128,000
Old Crow Boiler Metering and Control A hydronic heating system is used in Old Crow to provide heat to the buildings and engine blocks. The diesel boiler is used to satisfy heat demand when engine waste heat is not available. A meter will be installed to quantify the volume of fuel used.	\$25,000
Old Crow Plant Tank Access Old Crow has four 50,000 L diesel tanks to supply the power plants. These are horizontal double-walled tanks on individual skids, with a shared catwalk to access connections on top. The ground has shifted, pulling these tanks apart and stressing the catwalk welds to the tank. A new catwalk will be installed to provide access to all instruments and be supported independently.	\$232,000
Old Crow Unit 1 Major Overhaul Please refer to Business Case #23.	\$465,000
Old Crow Unit 2 Replacement Old Crow Unit 2 suffered a catastrophic engine failure in Q3 2019. The long block was replaced, rather than complete genset replacement, due to cost and schedule.	\$175,000
Old Crow Unit 3 Failure – Major Overhaul Old Crow Unit 3 had a bearing failure in Q1 2021 that damaged the generator. The generator was repaired at factory, rather than on-site, due to cost, quality, and warranty.	\$80,000
Old Crow Unit 4 Major Overhaul Please refer to Business Case #23.	\$252,000
Old Crow #2 Long Block Replacement	\$71,000

Please refer to Business Case #23. In Q4 2020, AEY observed a coolant leak. Troubleshooting determined the long block (received 2019) was deficient and required replacement. This was conducted in Q2 2021 but costs captured in 2022; manufacturer warranty and distributor goodwill credit covered the majority of costs.

- Old Crow Unit 2 Generator Refurbishment \$39,000

In 2015, Old Crow Unit 2 had a long block replacement: refer to AEY-YUB-46(b) Attachment 1 Appendix 3. This project was to complete a generator major overhaul, due to this piece of equipment reaching its service interval.

- Old Crow Old Plant Gantry Accessories \$21,000

The new gantry crane required low-profile trolley and hoist, to fit within the existing building clearance.

- Old Crow Plant (old) Gantry Crane \$22,000

Old Crow required a new certified gantry crane, for removal and maintenance of gensets, as the existing failed inspection and was not rated for Unit 1.

- Old Crow Original Plant Rebuild \$863,000

Please refer to Business Case 41 and AEY-YUB-46(b) Attachment 1 Appendix 1

- Old Crow Unit 3 replacement \$1,093,000

Please refer to AEY-YUB-46(b) Attachment 1 Appendix 2

- Old Crow Unit 2 – External Equipment \$51,000

The radiator and silencer were installed in 1993 for CUL# 371, prior to CUL #355 being installed in 2012. This project was to replace them with appropriately sized equipment for the current engine capacity, and due to end-of-life. Funds were not spent, and this risk has been managed by regular inspection.

2013-2015 Project Post Completion Summary

Attachment 11.2

Old Crow Plant Expansion

Project Summary and Description

The original generating plant in Old Crow did not have the physical capacity to house newer engines of the same or higher kW rating as the existing units reach end of life. It also did not have the space for additional units which are required as the community continues to experience load growth. Aside from the unit housing issues, the existing plant also did not have adequate floor or wall space to facilitate the installation of new control equipment. In order to address these issues and ensure contingencies are in place to minimize outages in the community, ATCO Electric Yukon installed a second 1,350 square foot generating building adjacent to the existing Old Crow plant.

Both the original and additional building have sufficient space to house two diesel generators and the associated equipment as well as provide sufficient working space for regular work to be performed safely.

Project Cost Update

Original estimates for this project were \$1,950,000 but, despite ATCO Electric Yukon's best efforts to minimize the costs while meeting the requirements of a safe reliable system, increased scope and unforeseen circumstances caused actual costs to be significantly higher than previously approved.

Actual and approved costs for this project were as follows:

	Approved (\$000s)	Actual (\$000s)	Variance (\$000s)	Variance (%)
Labour	60	238	178	297%
Contract Services	1,890	3,417	1,527	81%
Materials	-	336	336	-
Other	-	575	575	-
	1,950	4,566	2,616	134%

Building & Electrical Design (approx. \$1,300,000 additional costs)

A portion of the cost overrun is due to the updated design of the building structure. Original engineering and design provided to ATCO Electric Yukon at the time of the preparation of the 2013-2015 General Rate Application were preliminary. Additional detailed engineering and design work to integrate the updated building design with the existing system resulted in increased work scope and materials required.

The original forecast also did not include the electrical equipment required for the switchgear component for the additional building.

2013-2015 Project Post Completion Summary

Attachment 11.2

Construction, Installation & Commissioning Costs (approx. \$900,000 additional costs)

Conditions in the community significantly impacted the cost of this project. During construction, two other projects were being carried out in the community, which reduced availability of accommodations resulting in large increase of pricing. As a result contract workers, materials and resources within Old Crow were limited.

The existing store in the community closing prior to opening of the new store, due to construction delays of the new store. As a result food was either flown in or local catering services were utilized at an additional cost. Furthermore in part due to the new fuel depot construction, the community experienced occasional fuel shortages which resulted in additional delays or time onsite.

Whenever possible, ATCO Electric Yukon was diligent to use the lowest cost option. However, due to the size of the community and the limited resources available there was often only a single option to continue with construction of the project.

The quotes provided to ATCO Electric Yukon for the original design also did not compensate for the poor working conditions of the existing plant. More time was required to complete the work to integrate the two plants due to the space constraints and overall poor condition of the existing facility.

There was also additional unplanned site drainage work required in 2015, due in part to seasonal movement of disturbed permafrost from the excavation of the foundation in 2013.

Unforeseen situations such as weather conditions, flight availability, community events and aircraft mechanical issues, also resulted in delays which impacted work schedules resulting in additional labor and project management costs.

Freight (approx. \$100,000)

Old Crow is a fly in community with only one dedicated supplier of regular passenger and freight air service. A combination of other community projects and regular community demands limited the availability of transporting equipment and workers in and out of the community. As a result, additional costs for transporting equipment to site were encountered to ensure a timely delivery.

The charter of one Hercules aircraft was required in fall of 2015 to bring in the electrical switchgear plus construction material. Unfortunately, the only Canadian supplier of this service ceased operation in the spring of 2015. As a result Lynden transport out of Alaska was the only source available. In order to accommodate the delivery by Lynden all material had to be imported into the US (Alaska) to be exported back into Canada. Additional project management time was required to document and provide all the required information for the brokerage of this material.

2013-2015 Project Post Completion Summary

Attachment 11.2

Other (approx. \$100,000 additional cost)

Due to the large nature of the project various other incidental items increased the costs and additional timelines resulted in additional supervision and project management costs.

Economic conditions also impacted that cost of this project. At the time of the application the Canadian dollar was near par with the US dollar. The Canadian dollar steadily declined through the entire scheduled project timeline. Materials and the cost to fly in the switchgear were higher than ATCO Electric Yukon had anticipated partially due to the disparity between the Canadian and US dollar at the time of construction.

Other Considerations

Throughout the project, scope and costs were reviewed and revisited to ensure that ATCO Electric Yukon could address the load growth and provide adequate contingency to the community of Old Crow at a prudent cost.

As project scope and costs related to the building increased, modular options were explored. Quotes for this option came back between \$400,000-\$500,000 higher than the site built option and did not meet ATCO Electric Yukon's operational and maintenance requirements. There were significant costs related to transporting prefabricated structures to a community as remote as Old Crow. This modular unit did not have room for growth; it had space for one unit. The modular option would require an addition in the future in order to house additional or larger units as the community grows.

As there was still a need for a new building and Old Crow has been experiencing load growth over the last few years, ATCO Electric Yukon proceeded with the updated design. The building construction was tendered and the lowest bid was awarded the contract.



2016-2017 General Rate Application
Appendix #5

Old Crow Unit #3 Replacement



Executive Summary

Load growth and load duration of the Old Crow community have steadily diminished the utilization of the existing 170 kW unit due to its rated capacity. In order to address the load growth issues and ensure that there is sufficient contingency, ATCO Electric Yukon is proposing to purchase and install a new 600 kW unit to replace the existing undersized 170 kW unit. The new unit will be installed in the new building in Old Crow, as it will not physically fit in the existing building.

Business Case #15 "Old Crow Unit #3 Replacement" was submitted in the 2013-2015 General Rate Application and approved in Decision 2014-06. The unit tender and selection occurred in 2015; the unit will be received and installed in 2016.

Background

Based on the 2012 loading data (as submitted in the 2013-2015 General Rate Application), a project was identified that required a purchase of a 250 kW unit to replace the currently undersized 170kW unit in operation in the existing plant.

In preparation for tender of the new unit in 2015, a review of the current loading and consultation with key customers in the community took place. Based on this review and subsequent increases in connected load from 2012, a larger capacity unit (600 kW) was identified as being required.

Project Description

Multi-year project to replace the existing 170 kW unit, housed in the original Old Crow generating facility, with a larger 600 kW unit to be house in adjacent new building.

Manufacturer will also be responsible for disassembly and reassembly of unit to allow for transportation into the community via aircraft.

Unit will be installed within the new facility with structural, mechanical, and seismic engineering completed on the installation project to meet the applicable standards for a post disaster rated facility.



Project Schedule & Cost

This is a multi-year project. The tender and unit selection process occurred in 2015 with the unit scheduled to be installed in 2016. Total cost for this project is forecast to be \$1,262,000.

The original budget for this project as per the 2013-2015 GRA was \$500,000. The primary drivers for this cost increase are:

- Realization of actual costs based on previous projects in regards to construction and logistics of work completed within the isolated, fly-in only community;
- Understanding of construction and engineering requirements of installations carried out within the new facility; and
- Increase in physical size of unit, and associated costs in respect to transportation and installation as unit has to be disassemble for transport and reassembled on site.

Overall the first two items were the most significant causes of the increased forecast. The cost differential between a typical 285kW (based on a bids received for the Beaver Creek #2 Replacement) and 600kW unit is approximately \$60,000.

Business Drivers and Benefits

Load Growth

Load in Old Crow has been increasing over the last few years. Notable developments include the Water Treatment Center, Co-op Store, Fuel Depot, and new housing. Based on these developments and other factors within the community, a significant increase in peak load has occurred. With further potential development this peak is expected to rise. On average the peak has grown 4.023% based on 2008 – 2015 recorded values. The peak load has increased almost 21% since the original replacement unit was determined in 2012.

Old Crow Peak Loading 2008 – 2015

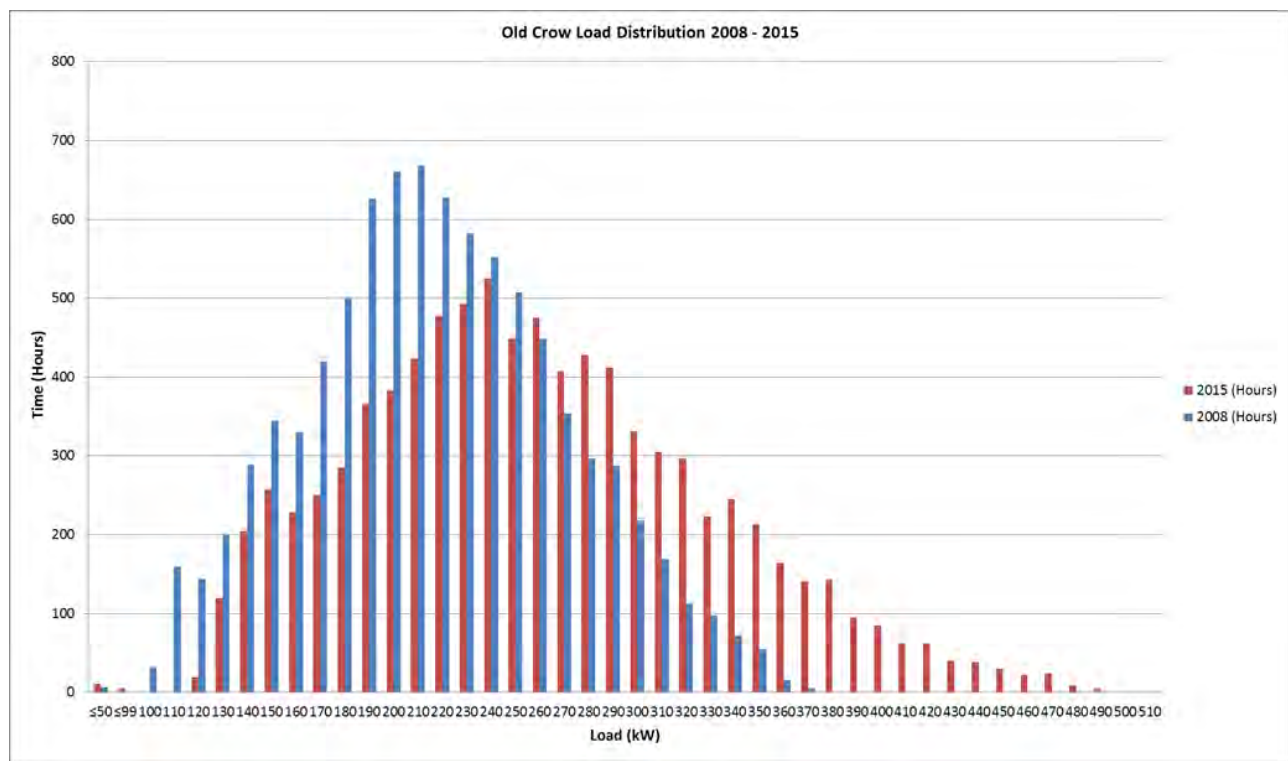
Year	Peak Load (kW)
2008	407
2009	460
2010	439
2011	478
2012	462
2013	481
2014	491
2015	558

Plant Efficiency

Sustained load growth within the community has impacted the overall load profile. As a result, the base load levels within the community have risen. Based on this trend, it is expected that the operational hours on a 250kW unit if installed would continuously decrease with load increase. This could result in the unit not operating under normal dispatch similar to the operation of the original 170kW unit.

Additionally this increase would reduce the possibility of the unit providing 100% community load under normal dispatch operation.

Old Crow Load Distribution 2008 / 2015



Contingency

The larger unit will not physically fit in the original facility where CUL 384 is currently housed. This new unit will be installed in the new plant adjacent to the original facility and provide additional contingency and mitigate the risk of long term outages within the community due to the loss of the original power plant for any reason.



Evaluation of Viable Alternatives

Alternative # 1: Leave existing 170kW unit in service. With continued load growth the unit will not run to provide 100% community supply under normal dispatch. The annual operating hours of the unit will continue to decrease.

Alternative # 2: Purchase and install 250kW unit as originally planned. Due to actual load growth, this alternative is not recommended, as it only provides short term solution. With continued load growth it is expected that this unit would see a continued decrease in hours of operation. Furthermore, the majority of project costs are related to logistics and installation, only a small differential in cost (\$60,000) is related to the price of a 250kW vs 600kW unit.

Alternative # 3: Replace the existing unit with a 600kW unit. Unit will be able to meet supply requirements of present load and provide capacity for future load growth.

Recommendation

It is recommended to replace Old Crow Unit #3 with a 600kW unit in the new plant adjacent to the original facility. This will address the load growth issue and improve contingencies in Old Crow.

Business Case for Actual Expenditures over \$100,000 2013-2015 Completed Projects

Attachment 11.7

Old Crow Unit #2 Replacement

Project Summary and Description

The replacement of Old Crow Unit #2 was originally forecasted to occur in 2016, as outlined in the 2013-2015 GRA response to information request YEC-YECL-19(a). The original forecasted 2016 replacement was based on the unit being due for a major overhaul at approximately 75,000 hours. ATCO Electric Yukon's current practice is to replace high speed machines near 80,000 hours or the closest life extension to 80,000 hours.

The scope of this project was to cover the supply, shipping, and installation of one 3421 long block for Old Crow Unit 2. Also included in the scope was disconnection, reconnection, new fluids, start up, commissioning, and return of existing block. Existing generator and skid were reused, with the generator to be serviced at a later date.

Project Costs

The project was completed in 2015 and the project costs were as follows:

Description	Actual (\$000s)
Old Crow Unit 2 Replacement	161
Total	161

Business and Technical Drivers

The original replacement date of 2016 was based on the 5 year average of the unit's operational hours. In 2013 the 5 year average was 5,881 hours, as of January 2016 the 5 year average increased to 6,093. The primary driver for the increase in operational hours is community load growth.

Throughout the 3rd quarter of 2015 the operation of Unit 2 continued to deteriorate with increased oil consumption, smoking, and valve wear. Due to the condition of the unit, there was a high probability that required replacement could not be delayed until the original forecast of 2016.

Alternatives

Alternative #1 - Purchase long block and replace existing engine - This option ensures the work will be completed before winter and the unit will physically fit in the power plant. The cost is comparable to a major overhaul with a higher probability of increased operational life.

Alternative #2 - Life extension on existing unit (major overhaul)- Perform major life extension on Unit 2 and operate in Old Crow for an additional 20,000 hours until replacement. While this

Business Case for Actual Expenditures over \$100,000 2013-2015 Completed Projects

Attachment 11.7

option would have delayed the purchase of a new unit, concerns around the downtime for the work were considered.

Alternative #3 - Replace unit with similar unit from Pelly Crossing - Pelly Crossing Unit 2 is a newer machine rated for 600kW and is the best match for the existing control system. However, the compatibility of the unit with existing mechanical equipment (exhaust silencer, radiator, and primary cable) would not allow it to handle 100% of the 600kW rated load.

Alternative #4 - Perform top end service, operate until April 2016 - A top end service is a minor over haul that is part of a regular maintenance schedule. It was determined that this maintenance service may not address the mechanical issues that are currently affecting the unit.

Alternative #5 - Accelerate the whole replacement of the unit to 2015 - Unable to procure a replacement unit and install before the winter season.

Recommendation

ATCO Electric Yukon determined that the best solution was the purchase of a refurbished long block and replacement of the existing engine of Old Crow Unit #2 and completed this work in 2015.



2023-2024 General Rate Application

Fish Lake Generation Capital Expenditure Information

FISH LAKE GENERATION

\$7,436,000

- The driver for most of the following projects is to comply with Water License HY12-065 that expires in 2038. Additionally, the expenditures related to the generating plants themselves are driven by the fact that they are nearing end of life. i
- Fish Lake Unit 2 – Replace Power Station – Detailed Design \$527,000
Please refer to Business Case #39.
- Fish Lake 1 Roof Replacement \$452,000
Please refer to Business Case #32.
- Fish Lake 2 Replace Power Station FEED \$385,000
Please refer to Business Case #39
- Fish Lake 2 Head Pond Intake Building Replacement \$153,000
The building will be replaced due to end-of-life; there are personnel hazards, failed structural components, and building envelope leaks. The substructure, containing trash racks and penstock intake, will be reused.
- Fish Lake 2 Head Pond Spillway Replacement \$975,000
Please refer to AEY-YUB-046(b) Attachment 2 Appendix 1
- Fish Lake Ditch 1 Failure \$262,000
Please refer to Business Case #02
- Fish Lake Ditch 1 Intake Building - Design \$103,000
The building shell was replaced due to end-of-life; new cantilevered structural elements were added for support.
- Fish Lake Unit 1 Spillway Diversion Structure \$772,000
This Spillway Diversion Structure is located at the northwest corner of the Unit #1 plant yard. It is required to divert and control all water from Ditch #1 Spillway to separate channels forming the entrances of West McIntyre Creek and Porter Creek. The existing structure is built of plywood and dimensional lumber that are at the end of their useful life. A new and adequately engineered structure is required.

- Fish Lake Unit 2 Assessment \$32,000

Fish Lake 2 had a failure because of a grid outage. Experts (Maven and ONEC Engineering) were retained to evaluate causes and required actions. The costs from 2016/17 were moved from capital to production operations in 2018. The test year cost of \$35,000 should have been captured in “Fish Lake Unit 2 Condition Assessment and Options Analysis” since the invoicing carried into 2023.
- Fish Lake Unit 2 Condition Assessment and Options Analysis \$66,000

These are the costs for the BBA Engineering report appended to Business Case #39. See above; the total cost was \$101,000.
- Fish Lake 2 TIV actuator and wicket gates \$37,000

These costs should be allocated to line 20; this is a duplicate.
- Fish Lake Unit 1 Roof Design \$59,000

Please refer to Business Case #32
- Fish Lake Unit 2 Bearing and Shaft Repair \$54,000

Following the failure in 2016, the thrust bearing and shaft required machining and resurfacing.
- Fish Lake Unit 2 TIV Replace \$47,000

During extended downtime on Fish Lake 2, the TIV froze and cracked and required replacement.
- Fish Lake 1 add TIV Actuator \$53,000

The TIV actuator and bypass valve actuator will be controlled from the PLC, to provide automated headpond level control and isolation in case of trip, reducing impact to waterway users and fish habitat.
- Fish Lake 1 TIV Replacement \$113,000

The manual ball valve originally installed was not functional (inoperable gear train, failed seals) and did not provide isolation. The TIV was replaced with a triple offset butterfly valve with motorized actuator.
- Fish Lake 2 add bypass valve actuator and automation \$35,000

The bypass valve will be replaced and will have a motorized actuator added, controlled from PLC, to provide headpond level control and

reduce impact to waterway users and fish habitat.

- Fish Lake 2 PLC replacement \$39,000

Fish Lake 2 PLC is obsolete and requires replacement. This is the last remaining PLC in the multi-year replacement program (lines 51, 52, 98, 102, 116 AEY-YUB-046(a) Attachment 1) for generating sites and this deficiency was identified in the BBA Engineering report.

- Fish Lake Unit 2 DC TIV Actuator & Wicket Gate Replacement \$138,000

Fish Lake 2 TIV has a motorized actuator (VAC) that is not functional on grid loss. A UPS battery bank and inverter will be installed to provide emergency closure of the TIV and bypass valves. The project title is because the original solution was to change the TIV actuator motor to VDC – however this option proved more costly than the one selected. In addition, the wicket gates and wear rings are end-of-life and require replacement to provide adequate turbine control and isolation. These risks were identified by Maven and BBA Engineering.

- Fish Lake Water Monitoring Upgrades \$248,000

Water monitoring upgrades in the Fish Lake Hydro system include instrumentation to gather flow and level data, telecommunications and solar/batteries for data historizing and reporting, and public safety signage – all of which are required to comply with water license conditions. These costs have been treated as an annual program. .

- Fish Lake Unit 1 Turbine and Building Replacement \$-9,000

The costs in S9.2 were removed since this project was closed in 2015.

- Fish Lake Ditch 3 Diversion Replacement \$2,801,000

Please refer to AEY-YUB-046(b) Attachment 2 Appendix 2.

- Louise Lake Containment Dyke Seismic Analysis \$40,000

An in-situ testing and seismic analysis is required to meet Canadian Dam Association guidelines pursuant to this infrastructure's assessed safety factor.



2016-2017 General Rate Application
Appendix #2

Fish Lake #2 Head Pond Spillway Replacement



Executive Summary

The Fish Lake Hydro system was built around 1950 and has aging infrastructure that is coming to the end of useful life. Investigative repairs of Fish Lake #2 Head Pond Spillway structure identified that the structure was in need of replacement. ATCO Electric Yukon will replace the existing spillway structure to adequately handle IDF flows while maintaining safe access to ATCO Electric Yukon generation facilities.

Background

In 2013 the existing structure was scheduled to undergo investigative repairs due to obvious signs of aging. These repairs were expedited when a sink hole was noted in the dam immediately adjacent to the structure in the summer of 2013.

During the investigative repair work it was apparent the structure had come to the end of its lifespan and needed significant repairs. The 2014 Dam Safety Report (recommendation #2014-09) identified the structure required replacement by the end of 2017.

Project Description

The scope of the project is to design and replace the existing concrete and wood structure with a new structure, capable of handling the IDF flows of 8.5m³/s.

Project Costs & Schedule

The project is scheduled to be designed in 2016 with construction completed in 2017. Design and engineering is estimated to be \$20,000 and the current construction costs is forecast to be \$593,000.

Project Schedule

The design of this project is scheduled to be completed in 2016 and construction is scheduled for 2017.

Business Drivers and Benefits

The main driver for this project is aging infrastructure. This project will ensure ATCO Electric Yukon complies with recommendation #2014-09 of the 2014 Dam Safety Report and item 42 of water license HY12-065.



Evaluation of Viable Alternatives

Alternative 1: Replace the aging structure. This alternative ensures ATCO Electric Yukon is compliant with the terms of the water license and ensures safe and reliable operation of the Fish Lake Hydro system.

Alternative 2: Replace after the structure fails. Failure of this structure inhibits ATCO Electric Yukon's ability to manage a flood event and poses significant risk to the remaining structures within the system.

Recommendation

ATCO Electric Yukon recommends replacing the existing spillway structure as recommended in the 2014 Dam Safety Report. This alternative mitigates the risks associated with a failure of the structure and aligns with ATCO Electric Yukon's commitment to provide safe, reliable service.



2016-2017 General Rate Application
Appendix #1

Fish Lake Ditch 3 Diversion Replacement



Executive Summary

Fish Lake Ditch 3 is not able to adequately handle a 100-Year Inflow Design Flood (IDF) event, as required to comply with recommendation item 2013-2 of the 2012 Dam Safety Report and ATCO Electric Yukon's current water licence HY12-065. In the event of an IDF event, the Ditch 3 infrastructure, including the Drop Box, would be at risk of catastrophic failure and risks impacting all remaining downstream infrastructure. As a result, ATCO Electric Yukon is planning to replace and upgrade the Ditch 3 Diversion structure and spillway to an engineered design that meets the IDF flow rates.

Background

On May 31, 2013, ATCO Electric Yukon was granted a 25 year extension to water use licence HY12-065. During the application process it was identified that Ditch 3 Diversion structure and spillway were not adequately built to withstand a 100 year flood event (Inflow Design Flood). ATCO Electric Yukon is planning to replace and upgrade the Ditch 3 Diversion structure and spillway to an engineered design that meets the Inflow Design Flood rates and complies with the terms outlined in the water licence. Please refer to Attachment 1 of this business case for a map of the Fish Lake facilities.

Project Description

Reestablishment of the Fish Lake Ditch 3 Diversion will allow water to escape the Fish Lake hydro system through a control structure and ditch to Franklin Lake. This project will construct a diversion structure and spillway ditch capable of diverting all water flows in excess of 4.4 m³/s (maximum capability of the Drop Box) out of Ditch 3 and into Franklin Lake prior to entering Ditch 3.

Project Schedule & Cost

This is a multi-year project. The draft design and spillway channel brushing occurred in 2014. Spillway channel surveying occurred in 2015, allowing ATCO Electric Yukon to update the design model and adjust the design accordingly. Rough grading, general fill, rip rap and filter rock supply and placement, and new discharge structure construction are scheduled to occur in 2016.



This project that was approved in ATCO Electric Yukon's 2013-2015 GRA for \$1,640,000. The updated cost forecast of \$3,049,000 is as follows:

Year	Actual (\$000s)	Forecast (\$000s)	Total (\$000s)
2013	16	-	16
2014	51	-	51
2015	67	-	67
2016	-	2,915	2,915
Total	134	2,915	3,049

The primary drivers for the cost increase between the previous forecast submitted in the 2013-2015 GRA are as follows:

Spillway Structure

The draft design consisted of a rock lined soil berm as a fixed crest overflow and included a single 600mm diameter culvert complete with slide gate/headwall. The final spillway design changed from the original concept of a simple fixed crest weir to the current 4 gated box culvert design and resulted in a \$480,000 increase to the forecast.

Operationally, the fixed crest weir would not have functioned well as a control point for regulating Franklin Levels as required within ATCO Electric Yukon's water licence HY12-065. Flow within the single culvert would have required very high levels in the ditch with minimal freeboard. Secondly, the Ditch would have had to reach near full capacity prior to the spillway becoming active (reactive control to an event). The new design allows controlled flow to Franklin Lake for regulating levels all while Ditch 3 levels are normal. Further, the spillway can be utilized pro-actively in the case of an event that can be reasonably forecasted.

Rock Quantity within Spillway Channel

The required rock quantity within the spillway channel increased as a result of detailed survey information that was not possible at the time of the conceptual design. This resulted in a \$530,000 increase to the forecast.

The channel had to be extended 50 meters at the Franklin Lake end to ensure the still basin would discharge at or near operational levels in Franklin Lake. Approximately 20 meters of additional channel was realized due to modifications to the spillway pilot channel and overall channel alignment. Overall, the channel saw approximately 10% increase in length. The lineal channel greater than 5.5% slope increased by 7%. The steeper channel requires additional rock armor protection.



Business Drivers and Benefits

Water Licence Compliance

ATCO Electric Yukon is required to comply with recommendation item 2013-2 of the 2012 Dam Safety Report and current water licence HY12-065. ATCO Electric Yukon is required to be able to adequately and safely manage a flood event. ATCO Electric Yukon also seeks to minimize the use of the Louise Lake Auxiliary Spillway and provide controlled inflows into Franklin Lake.

Protection of Existing Infrastructure

With the current inability to release water from the Fish Lake Hydro system upstream of Ditch 3, the Drop Box and Ditch 3 infrastructure poses a risk of catastrophic failure and risks of impact to all remaining downstream infrastructure during an IDF event.

Evaluation of Viable Alternatives

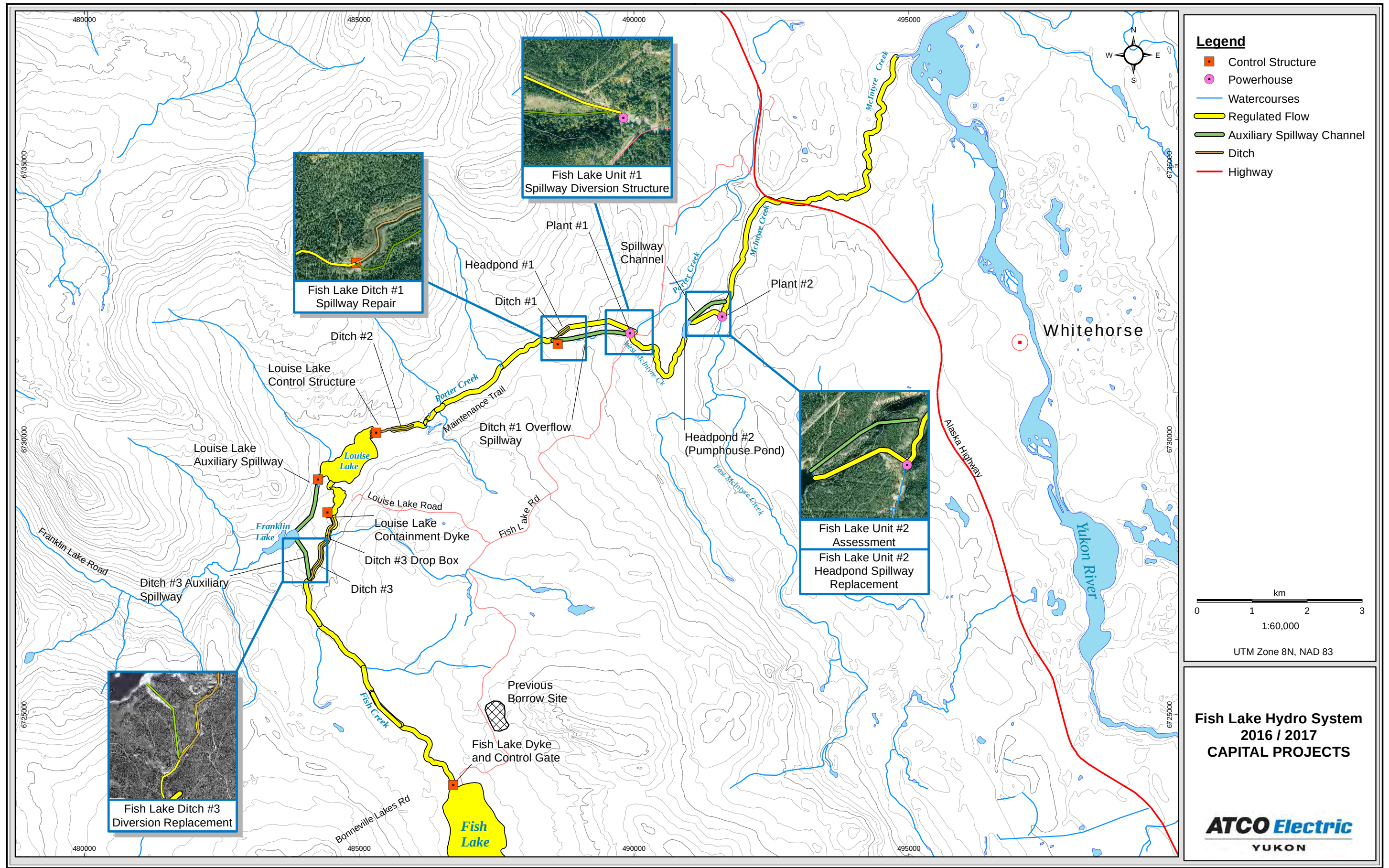
Alternative #1: Status Quo. This alternative could lead to future compliance issues with ATCO Electric Yukon's current water licence HY12-065. It also risks Fish Lake Ditch 3 infrastructure during an IDF event.

Alternative #2: Build a bypass structure at the Drop Box on Ditch 3. The bypass alternative was designed and studied; however the structure could still not adequately bypass 15.2m³/s of water flow which is the Inflow Design for Ditch 3. Ditch 3 infrastructure would still be at risk.

Alternative #3: Replace and upgrade the Ditch 3 Diversion structure and spillway to an engineered design that meets the IDF flow rates.

Recommendation

Replace and upgrade the Ditch 3 Diversion structure and spillway.



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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-047

Reference: 2023-24 GRA, Business Case #07 – Replace Watson Lake Generating Units, PDF pages 17-24

Issue: N-1-1

Quote: AEY employs a risk management principle that generating facilities on isolated community grids must have sufficient capacity to meet their peak load despite the loss of one operating unit while another unit is undergoing maintenance (N-1-1 criteria). The capacity that can be met under this N-1-1 criterion is known as the facility's Firm Capacity.

...

Based on this recommendation along with operational experience, AEY believes it is more cost effective and secure to replace these three units rather than overhaul the units with a significant risk that the life extension provided will not last long enough for operations to recover the investment nor provide sufficient reliability for continuing operations.

...

AEY has observed marginal improvements after a major overhaul in operation and reliability of 1200 RPM generating units operating passed the 100,000-hour mark.

Request:

- (a) How long has the stated criteria/risk management principle (N-1-1) been in place?
- (b) Has the Board previously approved this principle? If so, please provide the reference citing the Board Order and reasons showing this was accepted by the Board.

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- (c) Please provide a copy of the policy (N-1-1) to which this principle applies.
- (d) Please provide the economic analysis regarding the decision to overhaul or replace the Watson Lake generation units.
- (e) For each of the Watson Lake units replaced in Business Case #07, provide the availability of each unit for each of the three years prior to replacement and the percentage of that availability that was utilized.
- (f) Would other units that operate at a different RPM level be more efficient? Please explain.
- (g) Please explain why Watson Lake #5 underwent a major overhaul in 2022 and not a replacement. Please provide your economic analysis.
- (h) Since 2018, has AEY put out for tender all work related to either replacement or major overhauls of generation units? Please explain.

Response:

- (a) AEY employs a qualitative approach to this risk management, with subjective experience used to define consequence and likelihood of events. As mentioned in the Asset Management gap assessment, AEY's enterprise risk management system is still evolving.

In practice, the application of this criterion considers several specific conditions in Watson Lake and to AEY's operation. For example, this site has larger generators than other sites. This means that a major overhaul can make a unit unavailable for 4-12 weeks, depending on scope and other factors observed recently. In addition, AEY does not own a mobile genset of comparable size to those installed in Watson Lake so a rental would need to be sourced immediately if a spare was needed. Watson Lake is 5 hrs from Whitehorse service center where technicians are based, and remote from any service contractor or supplier inventory. Watson Lake's peak load is seasonal and generally increasing, but fluctuating and therefore difficult to predict.

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Therefore, it is possible for the largest unit to be out of service for maintenance (or due to a failure) for an extended period, which may include winter peak. Based upon AEY's ongoing operational experience, it is likely that within a 4-12 week period another unit would have an unanticipated trip - due to fault or protection or equipment failure. The result could be an outage in winter weather. The extent of the outage would be ~1000 customers in three communities, and its duration would depend on the cause of the trip. In a likely case, a critical part needs replacement and/or a tradesperson is required to repair – coming out of Whitehorse. In a worst case, parts are not available locally or more extensive repair is necessary.

Due to the foregoing, AEY has decided the risk of N-1 to be too great and N-1-1 is more appropriate to avoid the consequence of an outage in the Watson Lake Plant. This was reflected in the write-up for Business Case 3 and 13 in AEY GRA 2013-15.

- (b) Although the N-1-1 criterion has not been specifically discussed in past Board Orders, the principle of risk management as applied to unit sizing and capacity of a generating plant was discussed extensively in the 2016-17 GRA, as shown in Volume 3, page 479 onwards of the transcript.¹² The Board has also approved prior replacements of units 4 and 2 at the Watson Lake generating plant in the 2013-2015 and 2016-2017 AEY GRA's respectively.
- (c) AEY is proposing to develop an asset management program, which would include creation of strategic and specific asset management plans and progress on an enterprise risk management program (refer to METSCO report in BC #24) that is aligned with organizational goals. This would help articulate reliability objectives, operational risk mitigations, and maintenance practices for groups or classes of

¹ [https://yukonutilitiesboard.yk.ca/pdf/YECL_GRA_2016-2017/YUB-YECL_2016-2017_GRA_Vol_3_November_3_2016_\(unsecured\).pdf](https://yukonutilitiesboard.yk.ca/pdf/YECL_GRA_2016-2017/YUB-YECL_2016-2017_GRA_Vol_3_November_3_2016_(unsecured).pdf) PDF p. 94.

² https://yukonutilitiesboard.yk.ca/pdf/Board_Orders_2010/Board_Order_2017-01_Appendix_A_-_Reasons.pdf PDF p. 72.

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assets under a framework of defined business values and asset performance principles. Furthermore, contingency and critical spares procedures would be developed and documented as equipment risks are identified, evaluated and mitigated.

- (d) Beyond the identified lifespan, a genset's availability and utilization decrease and the cost to repair it increases, thereby increasing risk to the grid and to the ratepayer. AEY did not complete an economic analysis in the form of a lifecycle quantification of this risk, and comparison to specific alternatives, for the Watson Lake generation units. AEY has based its lifespan estimate for the generation unit, or replacement planning criteria, on industry practice and prior operating experience, having observed increased downtime and regular component failures as 1200 RPM units age beyond 100,000 hrs.
- (e) Below is a summary of Key Performance Indicators (KPIs) published to the YUB, for three-years prior to each unit's commissioned replacement:

Table 1: Key Performance Indicators (KPIs)

Unit	Metric	2017	2018	2019	2020	2021
WL#1	Availability			99.36%	82.9%	72.1%
	Capacity			84.54%	94.5%	63.3%
	Operating			40.21%	47.7%	46.7%
WL#3	Availability	95.9%	99.81%	68.76%		
	Capacity	80.55%	81.15%	82.36%		
	Operating	16.62%	23.73%	34.76%		
WL#6	Availability		99.7%	99.5%	83.4%	
	Capacity		78.82%	80.91%	92.4%	
	Operating		37.43%	31.13%	29.2%	

- (f) No. The referenced statement is intended convey that the lifespan for 1200 RPM units is 100,000 hrs. 1800 RPM units have a shorter expected lifespan and shorter recommended interval between overhauls such that they are less efficient in that respect.

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- (g) WL5 underwent a major overhaul at 37,276 hrs., or at an interval of approximately 22,500 hrs. since its last major overhaul. A replacement would be considered closer to its end of life at 80,000 hrs, since this is a 1800 RPM unit. end of life.
- (h) AEY has conducted tendering or RFP processes for the referenced replacement projects including for equipment supply, engineering consultants, and installation contractors pursuant to ATCO's purchasing policy and sourcing and procurement guidelines. As described in Business Case #23 and AEY-UCG-085(b), AEY outsources major overhauls to qualified contractors. Since 2014, this has been conducted by a contractor on a Master Services Agreement with AEY.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-048

Reference: 2023-24 GRA, Business Case #35 – ArcticPharm Yukon's Independent Power Production (IPP) Site, PDF pages 135-137

Issue: Customer contribution

Quote: This is a fully contributed Customer-Driven Interconnection Project. AEY has an obligation to serve customers in (sic) with electrical supply.

Request:

- (a) Please confirm that this project will have no net impact on AEY rate base or revenue requirement. If not confirmed, then please explain any impact.
- (b) Who is responsible for costs that exceed budget/forecast for the IPP projects? Please explain.

Response:

- (a) There will be no net impact on AEY rate base assuming the contribution is applied to the relative capital project and not utilized to fund existing rate base. There will be a net impact on revenue requirement because the assets themselves are AEY assets and, as such, any operating and maintenance costs required for safe and reliable operation would be included in revenue requirement going forward.
- (b) The Independent Power Producer (IPP) customer is responsible for the costs of connecting the IPP project to the grid. The forecasts are used by the IPP to evaluate the feasibility of the overall project in the planning stage and to choose between options where applicable.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-049

Reference: 2023-24 GRA, Business Case #35 – ArcticPharm Yukon’s Independent Power Production (IPP) Site, PDF pages 135-138; 2023-24 GRA, Business Case #36 – Haeckel Hill Customer Connection, PDF pages 139-143

Issue: Capital expenditures (New Extensions-IPP)

Quote: PDF page 136:

2. ArcticPharm has signed an Electricity Purchase Agreement (EPA) with Yukon Energy Company (YEC), and YEC has directed AEY to complete the required upgrades. AEY’s customer for this project is YEC.

PDF page 140:

2. EHLP has signed an Electricity Purchase Agreement (EPA) with YEC, and YEC has directed AEY to complete the required upgrades. AEY’s customer for this project is YEC.

Request:

- (a) For each of the referenced business cases, please explain the nature of YEC’s direction to AEY to complete the required upgrades?
- (b) For each of the referenced business cases, please explain if AEY has completed the project in July 2023 as forecast. If not, please summarize the work completed to date and the revised date of completion of each project.

Response:

- (a) For each of the referenced Business Cases, YEC provides direction to AEY through its review and approval of the design, cost estimate and schedule provided by AEY to YEC for IPP projects that connect to the Yukon Integrated System (YIS)

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through AEY's distribution system. The reason for this process is that YEC has the "commercial" relationship with the IPP in the form of an EPA between YEC and the IPP. The EPA states how the financial terms of the agreement will be handled. Generally, the IPP is required to pay YEC up front for all new and upgraded infrastructure required to connect the IPP to the YIS. As YEC is required by the EPA to collect funds for construction of facilities to connect the IPP to the YIS whether directly from their system or through AEY's distribution system, YEC is responsible to ensure AEY is paid for the work completed as these projects are fully contributed by the IPP. This means that YEC becomes the "customer" for this project and is responsible to approve the work. This is no different than any other new customer extension attaching to AEY's distribution system.

- (b) EHLP - As of September 15, 2023, all work on AEY's distribution system has been completed for this project to connect to the YIS.

ArcticPharm – As of September 15, 2023, AEY has completed the upgrades and new infrastructure to connect this project to the YIS. The outstanding work to be completed is programming protection settings into the new and existing devices on the portion of distribution system to which the IPP connects.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-050

Reference: 2023-24 GRA, Business Case #36 - Haeckel Hill Customer Connection, PDF pages 140-142

Issue: Customer contribution

Quote: This is a customer-driven interconnection project. AEY has an obligation to serve customers in the City of Whitehorse with electrical supply. This (sic) a fully customer contributed project.

Request:

Please confirm that this project will have no net impact on AEY rate base or revenue requirement. If not confirmed, please explain any impact.

Response:

There will be no net impact on AEY rate base assuming the contribution is applied to the relative capital project and not utilized to fund existing rate base. There will be a net impact on revenue requirement because the assets themselves are AEY assets and, as such, any operating and maintenance costs required for safe and reliable operation would be included in revenue requirement going forward.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

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Reference: 2023-24 GRA, Business Case #37 – Kluane Wind Turbine Integration, PDF pages 145-146

Issue: Customer contribution

Quote: This is a fully contributed customer-driven interconnection project.

Request:

Please confirm that this project will have no net impact on AEY rate base or revenue requirement. If not confirmed, please explain any impact.

Response:

There will be no net impact on AEY rate base assuming the contribution is applied to the relative capital project and not utilized to fund existing rate base. There will be a net impact on revenue requirement because the assets themselves are AEY assets and, as such, any operating and maintenance costs required for safe and reliable operation would be included in revenue requirement going forward.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-052

Reference: 2023-24 GRA, Business Case #38 – Beaver Creek Photovoltaic Project, PDF pages 148-149

Issue: Customer contribution

Quote: This is a fully contributed customer-driven interconnection project.

Request:

Please confirm that this project will have no net impact on AEY rate base or revenue requirement. If not confirmed, please explain any impact.

Response:

There will be no net impact on AEY rate base assuming the contribution is applied to the relative capital project and not utilized to fund existing rate base. There will be a net impact on revenue requirement because the assets themselves are AEY assets and, as such, any operating and maintenance costs required for safe and reliable operation would be included in revenue requirement going forward.

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**ATCO Electric Yukon (AEY)
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**Information Responses Round 1 to:
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Reference: 2023-24 GRA, 2018-2022 Business Case #18 – New Services Overhead and Underground, PDF page 77, Table 1 and paragraph 4

Issue: Capital expenditures (New extensions)

Quote:

Project Schedule and Cost

**Table 1: New Services Overhead and Underground
(\$000)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
New Services Overhead and Underground	1,747	1,600	2,555	2,701	2,483	3,873	2,777	4,219	4,324

4. Customer driven services that are undertaken to meet customer needs. Most of these projects are fully funded. Further explanation is provided below for projects that are not fully funded where the net amount capitalized exceeds \$100,000.

Preamble: It is not clear whether the amounts shown in Table 1 are net of contributions.

Request:

- (a) Please clarify if the amounts shown in Table 1 are net of contributions. If confirmed, please breakdown Table 1 into rows which will show the total costs, the contribution amount received and the net amount. If not confirmed, please insert a row below Table 1 to provide the total contributions received for AEY's New Services Overhead and Underground.
- (b) Referring to Table 1, given the significant increases in capital expenditures forecast for 2023-24 in comparison to the work completed in the prior years, please explain how AEY plans to complete the work associated with this project. Please

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include an explanation addressing how AEY will prioritize the work associated with this project if faced with competing deadlines from other projects it has asserted are equally or more critical.

Response:

- (a) Not confirmed. The amounts shown in Table 1 are only capital expenditures. Refer to the Table 1 below for contributions received for New Services Overhead and Underground.

**Table 1: New Services Overhead and
Underground Capital and Contribution Expenditure
(\$000)**

	Actuals							Test Period	
	2016	2017	2018	2019	2020	2021	2022	2023	2024
Capital Expenditures	1,747	1,600	2,555	2,701	2,446	3,846	2,777	4,219	4,324
Contribution	(870)	(477)	(994)	(2,218)	(1,525)	(2,574)	(2,895)	(3,634)	(3,243)
Net Total	877	1,124	1,561	483	921	1,272	(118)	585	1,081

- (b) Please refer to the response to AEY-YUB-042(b). The new extension work will be bundled by service areas, be made shelf ready and contracted out as much as possible. This will allow company crews to focus on projects with more critical timelines.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

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Reference: 2023-24 GRA, 2016-17 Business Case #01 – McIntyre Subdivision Rebuild Capital, PDF pages 1-7; 2023-24 GRA Schedules, S9.2, Line No. 191

Issue: Capital expenditures (Distribution Improvement)

Request:

- (a) Please explain why the approved 2016-17 forecast capital expenditures shown on S9.2, Line No. 191 (\$0.564 million and \$0.924 million respectively) do not match approved 2016-17 forecast capital expenditures shown in BC#01, Table 1, for the same years (\$0.740 million and \$1.186 million respectively).
- (b) Please prepare an actual-to-approved variance analysis for the years 2016-17 using the approved 2016-17 forecast capital expenditures shown on S9.2.
- (c) Please explain why the 2023-24 forecast capital expenditures shown on S9.2 (\$0.109 million and \$1.244 million respectively) do not match the capital expenditures shown in BC#01, Table 3, for the same years (\$0.521 million and \$1.399 million respectively).
- (d) Please prepare a life-to-date summary table (2013-2025) for the project and provide the actual capital expenditures incurred each year and the applicable forecast. Please confirm that all costs identified in the summary table remain in “construction work in progress”. If not confirmed, please explain. Where applicable for a given year, please identify any costs that were the result of project scope changes.

Response:

- (a) Business Case #01 was split into two different line items within Schedule S9.2 to differentiate between asset classes within the project.

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Table 1 reflects the sum of the 2016 and 2017 approved values in line 191 and line 322 of S9.2.

- (b) As noted in the response to part (a), Table 1 in Business Case #01 reflects the sum of the 2016 and 2017 approved values in line 191 and line 322 of S9.2. 2016 has a variance of 1 percent, which is an insignificant and reasonable amount. 2017 has a variance of -13 percent and, as mentioned in paragraph 8, “All the planned civil work was completed but the electrical installation and overhead powerline salvage was delayed to Q1 2018, which resulted in underspending in 2017.”
- (c) Business Case #01 was split into two different line items within Schedule S9.2 to differentiate between asset classes within the project.

Table 3 reflects the sum of the 2023 and 2024 Test Period values in line 191 and line 322 of S9.2.

- (d) Please refer to the table below for a summary by year of the McIntyre Subdivision Rebuild (including streetlights). Note that for the years 2016 to 2022 the costs of the streetlights were included in the overall rebuild cost on Schedule 9.2, AEY will update this presentation in the Compliance Filing to the Application.

McIntyre is a phased project and, as phases go into service, AEY has removed them out of work in progress and capitalized the costs. AEY has included these costs, net of accumulated depreciation expenses. AEY notes the net cost of capital has been included in the 2023-2024 Revenue Requirement on a prospective basis and AEY is not seeking retroactive recovery of returns or depreciation costs incurred for the period since its last GRA. The expenditures from 2013 to 2020 listed in the table below have been capitalized.

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**Table 1: Actual/Forecast vs Approved Costs
(\$000)**

Actual/Forecast				Approved			
Year	Rebuild	Streetlight	Total	Year	Rebuild	Streetlight	Total
2013	656	-	656	2013	475		475
2014	418	-	418	2014	250		250
2015	379	-	379	2015	-		-
2016	617	131	748	2016	564	175	739
2017	890	145	1,035	2017	924	254	1,178
2018	362	43	405	2018			-
2019	116	25	141	2019			-
2020	(81)	(10)	(91)	2020			-
2021	1,201	167	1,368	2021			-
2022	277	8	285	2022			-
2023	521	412	933	2023			-
2024	1,244	155	1,399	2024			-
2025	50	-	50	2025			-
Total	7,159	567	7,726	Total	2,213	429	2,642

**Table 2: Costs Related to Scope Changes Since 2016-2017 GRA
(\$000)**

Year	Cost due to Scope Change	Description of Scope Change
2013	50	Added pullbox as existing cables were deeper than expected.
2014	40	Added streetlights to wood poles to bring lighting to similar levels as previous underground fed lights. Added one overhead transformer to convert a service to overhead line.
2015	-	
2016	30	Added risers to keep mainline overhead along McIntyre drive instead of converting McIntyre to underground in stages as originally planned. These risers were for feeding local residential streets. Added streetlights to wood poles to improve lighting.
2017	115	Added 5 risers to feed local residential streets from McIntyre overhead mainline, extra trenching, an additional switch modular for operational need, and additional low voltage pedestals to serve residential lots. Added streetlights to wood poles to improve lighting.

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Year	Cost due to Scope Change	Description of Scope Change
2018	100	Added 6 risers to feed local residential streets from McIntyre overhead mainline, added one switch modular for operational need, one additional transformer and one pedestal to serve residential lots.
2019	100	Additional conduit and trenching to account for system changes, new customers since McIntyre project started, and potential future development.
2020	-	
2021	-	
2022	-	
2023	120	Added a switch modular for operational need, 2 pull boxes, and one riser to keep mainline electrically connected.
Total	555	

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-055

Reference: 2023-24 GRA, 2016-17 Business Case #03 – 400 Amp Regulators in Logan Substation; 2023-24 GRA Schedules, S9.2, Line No. 214

Issue: Capital expenditures (Distribution Improvements)

Request:

Please provide a variance explanation for the increase in costs from those approved (\$0.122 million) and the actual costs (\$0.174 million) incurred.

Response:

The initial cost estimate developed for this project in January 2017 was \$122,000. The estimate based on 2016 values equaled \$141,000. The final build price came out to \$174,000 due to increased cost of materials at the time the work was completed in [2017] compared to the cost of materials in [2016] used in the estimate.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
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Received: September 6, 2023**

AEY-YUB-056

Reference: 2023-24 GRA, 2018-2022 Business Case #12 – Annual right of Way Widening, PDF page 52, paragraph 5; 2023-24 Business Case #26 - Annual Right-of-Way (ROW) Widening, PDF page 83, paragraph 5

Issue: Capital expenditures (Distribution Improvements)

Quote: Currently, AEY does not use any herbicide applications.

Request:

Please explain whether AEY has explored the use of herbicides for its required brushing work. If so, please provide any qualitative and quantitative cost-benefit analysis that was conducted during AEY's research respecting the use of herbicides. If not, please explain why.

Response:

To date, AEY has not explored the use of herbicides for annual ROW widening brushing work. This work involves removing older growth that had not previously been cleared to AEY standards or hazard trees outside the existing ROW. This vegetation is to be removed at the time of brushing activities.

The brushing method of mowing ROW has proven to be effective in areas that have either been cleared of larger growth or have smaller species growth (willows etc.). Mowing provides a clear safe ROW for the public as it involves mulching of the vegetation as it is dispersed back to the ROW.

Herbicides are currently used at AEY substation sites. These locations are secured and gated to the public. These locations also contain critical electrical equipment which must

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remain clear of vegetation for safe and reliable operation. These applications of herbicide are conducted annually.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-057

Reference: 2023-24 GRA, 2018-2022 Business Case #15 – Line Moves in Highway ROW, PDF page 67, paragraph 4

Issue: Capital expenditures (Distribution Improvements)

Quote: YK 1045669 AEY Powerline Relocation YG Alaska Hwy Crestview Phase 1 of 2;

- 25 kV relocate in Phase 1.
 - o Phase 2 was deferred due to YG roadwork delay.

Request:

Please clarify if Phase 2 has been completed and, if so, provide a reference to where all relevant information respecting this project has been provided in AEY's GRA.

Response:

Phase 2 has not yet been started. AEY is awaiting confirmation from the Yukon Government regarding when this work will be required.

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**ATCO Electric Yukon (AEY)
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**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-058

Reference: 2023-24 GRA, 2018-2022 Business Case #16 – Dual Rated Transformer Upgrade, PDF pages 69-72, paragraph 2; 2023-24 GRA Schedules, S9.2

Issue: Capital expenditures (Distribution Improvements)

Quote: This is a part of a larger long-term plan to modernize the electrical supply and increase capacity of the system in downtown Whitehorse. This project was initially contemplated in 2013 but due to slower than anticipated load growth it was deferred. It was revisited within the 2016-17 GRA and is an action item identified in appendix 9 to that filing.

Preamble: The Board is unable to confirm costs associated with this business case in AEY's 2023-24 GRA Schedules, S9.2.

Request:

- (a) Please provide line number references to where the costs (2016-17 approved, 2016-2022 actual and 2023-24 forecast) for this project are reflected between the years 2016-2024 within GRA Schedules, S9.2.
- (b) Please clarify if AEY received approval for the costs for this project as a part of the revenue requirement in a GRA, when it was "initially contemplated in 2013".

Response:

- (a) These costs are reflected in lines 344 and 347 of AEY's 2023-24 GRA Schedules, S9.2. General Capitalizable Transformers and Transformers and Regulators.
- (b) Yes. Board Order 2014-06 - ERRATA approved YECL's 2013-2015 revenue requirement. Business Case 24 in YECL's 2013 GRA submission speaks to changing out equipment to 25 kV rated equivalents, in pursuit of AEY's long term

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Downtown voltage conversion plan. Downtown Whitehorse voltage conversion remains a key item in AEY's long term system plan as electrical load continues to grow in the area.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-059

Reference: 2023-24 GRA 2023-24, Business Case #25 – New Substations - Mayo Road and Whistle Bend, PDF pages 67-81, paragraph 5

Issue: Capital expenditures (Distribution Improvements)

Quote: Two new substations will be built to support the North 25 kV system. The first – Mayo Road substation – will be near the intersection of Klondike Highway North and Takhini Hot Springs Road. The second – Whistle Bend 2 Substation – will be in the Northwest corner of the Whistle Bend community.

Preamble: The Board requires further detail for Business Case #25.

Request:

- (a) AEY's business case forecasts the construction of two substations within a period of less than three years. Please provide a detailed construction timeline noting all approvals required by any person(s) or governmental body(ies) aside from the Yukon Utilities Board in order to proceed with the project at a given stage of the timeline.
- (b) Please provide the comparative cost-benefit analysis prepared for each alternative, including the analysis of "previously completed substation projects and the main expected costs for each design."
- (c) Please explain AEY's plans for material sourcing and availability with respect to these two substation projects. Please include in the response any unit and unit cost detail currently available by major material component (e.g., transformers, regulators, switches, land, etc.).
- (d) Please provide a historical timeline (both forecast and actual timelines achieved) for the construction of AEY's last substation project build.

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Response:

(a) Please refer to the following table for the detailed project schedule:

Table 1: Detailed Project Schedule

Task	2022	2023	2024	2025
Order long lead items (Tx, Reg)	Q1	Q3		
YG – Land Application	Q4	Q3		
Start Detailed Engineering		Q1, Q4		
Submit YESAB Application		Q1, Q3		
Order Major Equipment (Reclosers, Switch Cubes, Communication Bldg)		Q2, Q4		
HazCOM Design Review		Q3	Q2	
Receive YESAB Decision Document		Q3	Q3	
YG – Land Lease		Q3	Q3	
YG – Work in ROW Permit		Q3	Q3	
City – Development Permit			Q3	
Receive long lead items and major equipment		Q4	Q3	
Construction – Clearing, Grubbing, Geotechnical		Q4	Q3	
Construction – Undergrounds, Grading, Access Road			Q2, Q3	
Construction – Equipment, Concrete, and Cable			Q3	Q2
YG – Building Permit			Q3	
City – Building Permit			Q4	
Construction – Overhead, Communications, Interconnection			Q3	Q2

Blue = Mayo Road, Red = Whistle Bend

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- (b) Please refer to the following cost-benefit analysis prepared for each of the three alternatives, included as Table 6 in the Business Case. Please refer to AEY-YUB-059(b) Attachment 1 for the complete cost analysis table in Appendix B. It is important to note that the costs shown in the Attachment 1 do not represent the total project costs, only a comparative cost between Alternatives. A description of the method is written in section 3.4 of Attachment 1. Equipment and labour costs have also increased significantly above the base costs shown in Appendix B of Attachment 1 since Selkirk substation was built in 2017.

Table 2: Cost Benefit Analysis

				Alternative 1		Alternative 2		Alternative 3	
Criterion type	Criterion	Criterion Weight	Threshold Value	Rating	Score	Rating	Score	Rating	Score
Eliminatory	Additional Transformer Capacity	4	3	5	20	5	20	5	20
Eliminatory	Resolve Laberge Regulator Overload	4	3	4	16	4	16	4	16
Ranking-only	Improve System Voltage	2	3	2	4	4	8	4	8
Ranking-only	Ease of Switching/Operation	2	N/A	4	8	4	8	4	8
Ranking-only	Utilization of New Apparatus	3	N/A	4	12	2	6	4	12
Ranking-only	Project Cost	5	N/A	3	15	2	15	3	10
Totals:				75		68		79	

- (c) Delivery timelines for major materials are longer than in prior years, due to global supply chain and logistics constraints. ATCO does provide AEY with greater purchasing power and inventory access. Longest lead equipment (transformers,

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regulators) is ordered in advance of the completion of detailed engineering, based on ATCO standards and consistent sizing and specifications.

**Table 3: Mayo Road Substation
(\$000)**

Major Equipment	Qty	2022	2023	2024
Transformer	1	400		-
Regulators	3	-	325	-
Switch Cubicles	2	-	50	-
Reclosers	2	-	150	-
Communication Bldg	1	-	40	-

**Table 4: Whistle Bend Substation
(\$000)**

Major Equipment	Qty	2024
Transformer	1	400
Regulators	3	110
Switch Cubicles	4	112
Reclosers	4	220
Communication Bldg	1	40

(d) The Selkirk substation timeline is outlined in the table below.

Table 5: Selkirk Substation Timeline

	Forecast Timeline	Actual Timeline
Start of land procurement/permitting	Sept 2013	Sept 2013
Substation design finalized	Mar 2015	Mar 2015
Land procurement/permitting is completed	Oct 2015	Oct 2015
Project Kick-off	Feb 2016	Feb 2016
Substation brushing complete	May 2016	May 2016
Civil construction starts	May 2016	May 2016
Electrical construction starts	May 2016	Sept 2016
Civil construction completed	Nov 2016	Nov 2016
Electrical construction completed	Nov 2016	Oct 2017 ¹
Substation In Service Date	Dec 2016	Dec 2017

¹ Delay due to damaged material and winter weather conditions.



Whitehorse North 25kV New Substation Analysis

Technical Appendix

Revision History

Revision	Date	Editor	Comments
R0.2		Ryan Grams	Document Created

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1. Problem Statement

The Whitehorse North 25kV system is expecting significant load growth over the next 5 years that cannot be adequately supported by the existing system. As identified in the Whitehorse North 25kV System Study conducted in October 2019, system upgrades will be required in order to handle both normal peak power levels and all N-1 contingency scenarios. To correctly address these issues, a combination of upgrades to existing infrastructure and the construction of new substations were considered, resulting in the development of 3 distinct solutions: a new Whistlebend Substation (WB2), a Takhini Hot Springs Road Substation (TK1) with upgrades to Laberge, and a combination of a new Takhini Hot Springs Road Substation and a new Whistlebend Substation.

2. Background

A study of the North 25kV system was completed in order to analyze the system's ability to support new load growth over the next 5 years (up until 2025). The study found 3 key system deficiencies: the Laberge regulators are expected to over-current at peak loads in 2025, the North 25kV system peak load will not be able to support a single 25/34.5kV transformer outage in 2025, and presently the North 25kV system cannot support a primary 34.5kV bus outage at Whistlebend. These deficiencies are based on expected system peak loads that were created through a combination of historical loading and planned upcoming developments. Based on 2016-2018 data, Whitehorse peak loading increased at a rate of 3% per year and it is assumed that typical loads will grow at this rate for the 5-year planning period. Additionally, large new load additions in the form of Whistlebend stages 4 through 7 and new construction on Takhini Hot Springs road have been forecast on top of the 3% as they are expected to add a combined 7MW of load by 2025. Altogether peak loading on the North 25kV system is forecast to increase from its current level of ~11MW up to ~21MW by 2025. For the following models analyzed in this study, all loading levels are based on expected peak customer loads in 2025 assuming unity coincidence factor among feeders (all feeders experience their peak at the same time, but not all customers necessarily peak simultaneously).

3. Evaluation Criteria

3.1 Equipment Capacity

As identified in the previous North 25 System planning study, over the next 5 years, expected load growth will result in new system requirements. Specifically, to maintain a robust system that can operate in any N-1 contingency without large system failure, additional 34.5/25kV transformer capacity is required. This is mainly due to the potential scenario where the primary bus to Whistlebend undergoes an outage, taking both T1 and T2 offline. In order to maintain service to the Whistlebend subdivision in this scenario, at a bare minimum 10.7MVA of additional transformer capacity is required (assuming switching allowed all other transformers to divide load evenly). In reality, additional transformer capacity of 15-20MVA is required depending on where it is located in the system.

Additionally, based on current expected loading levels, it is expected that Laberge Regulators (R50, R51, R52) will be overloaded by 2025. Therefore, any potential solution must address this problem by either off-loading from Laberge to another source, or by upgrading these regulators.

3.2 Contingency Scenarios

After analyzing all of the possible N-1 contingency scenarios that could face the North 25kV system, the following 2 scenarios were identified as requiring system upgrades at or before 2025:

Contingency 1: The loss of a single 10MVA 34.5/25kV transformer in the North 25kV system. At present configuration, a loss of any of the 3 sub-transmission transformers would create a system overloading issue with 2025 expected loading levels, however it was determined that a loss of Laberge would be the worst-case of the 3. This is mainly due to the increased voltage-drop issues when Crestview and the highways are supplied by Whistlebend.

Contingency 2: The loss of the primary 34.5kV bus at Whistlebend Substation, resulting in an outage to both Whistlebend transformers. This scenario results in all of the load currently serviced by Whistlebend transformers requiring an alternative source. Present-day loading levels in this scenario would already exceed the capacity of Laberge's single transformer and 2025 loading levels are expected to intensify this problem.

3.3 Voltage Improvement

As feeder loading grows to the expected 2025 levels, the North 25kV system will experience wide-spread under-voltage (below 0.95 p.u.) along both the Alaska and Klondike Highways North. These problems can be addressed by the addition of regulators, however to minimize the risk of load rejection, it is preferred that system additions improve voltage levels by decreasing the resistance between a source and load (e.g. shortening the length of line from substation to customer transformer). For equal comparison of all options, all new substation voltage regulators proposed have been modelled with a setpoint of 124V.

3.4 Cost Analysis

As a regulated utility, it is important that all costs are necessary and justifiable. Intrinsic to this, is the requirement to choose the most cost-effective option when comparing equivalent options. Within Section 4: Proposed Solutions, the 3 solutions presented all aim to solve the same goals, however they do so in different ways and therefore cannot be solely analyzed based on cost alone. To compare these options, a decision matrix was developed to provide a clear grading scheme for evaluating the 3 proposed solutions (see Section 5).

The cost section of the decision matrix has been assigned the largest relative weighting and will therefore have a significant impact on each solution's final score. To determine estimate costs for these solutions, a relative-costing strategy was utilized. Instead of comprehensively listing every item that is expected to be required, items of insignificant cost or items that are common to all solutions were ignored and the costs for unique or large items in each proposed solution

were totaled. This provides a relative difference in estimated costs among the 3 alternatives without requiring a comprehensive estimating process.

3.5 Protection Settings and System Re-Configuration

All of the 3 proposed solutions will require new protection settings for the north 25kV feeders and some system reconfiguration/redistribution of the existing reclosers and other protective devices. As these requirements will be common to all solutions, they have not been included as part of this study and will be considered outside of the analysis scope.

4. Proposed Solutions

Using the evaluation criteria listed above, the following solutions have been developed:

4.1 Option A: Whistlebend Substation 2 (WB2)

4.1.1 Overview

The first proposed solution focuses around the construction of a new substation situated west of Whistlebend Stage 7 along existing 25kV line 5L648. This substation would primarily service two load centres: Whistlebend stages 4-7 and line 5L645 serving the Alaska and Klondike Highways north of Whitehorse. By servicing these areas, WB2 will offload approximately 6MW from Laberge Substation and 6.5MW from Whistlebend.

4.1.2 Equipment/Apparatus Requirements

In order to meet the 2025 system requirements detailed in section 3.1, WB2 needs to provide at least 10.7MVA of 34.5/25kV transformer capacity to the North 25kV system. To meet this target, as well as to provide opportunity for future growth along the North 25kV system, WB2 would include 2 separate 10MVA transformers, 6 matching 400A 25kV regulators, and 3 SCADA-controlled 630A substation reclosers. During regular operation, these breakers would service the Alaska and Klondike Highways north of Whitehorse, Whistlebend stages 4-7, and a N/O hot-spare to supply Whistlebend stages 1-3 through S3434 in the event of an outage on Whistlebend T1 or T2 (see section 4.1.4). A single-line diagram (SLD) for Whistlebend Substation 2 is included in Figure 1 below. A summary of the large apparatus required for this proposal is listed below:

- 2 x 10MVA 34.5/25kV Transformers
- 6 x 400A 25kV Regulators
- 3 x 630A 25kV Reclosers

Additionally, the regulators installed at Laberge Substation (R50, R51, R52) are still anticipated to be overloaded during a Contingency Scenario 2, therefore this apparatus will also require an upgrade. The next standard size of regulator AEY utilizes is rated for 400A and will adequately meet the expected loading on this device.

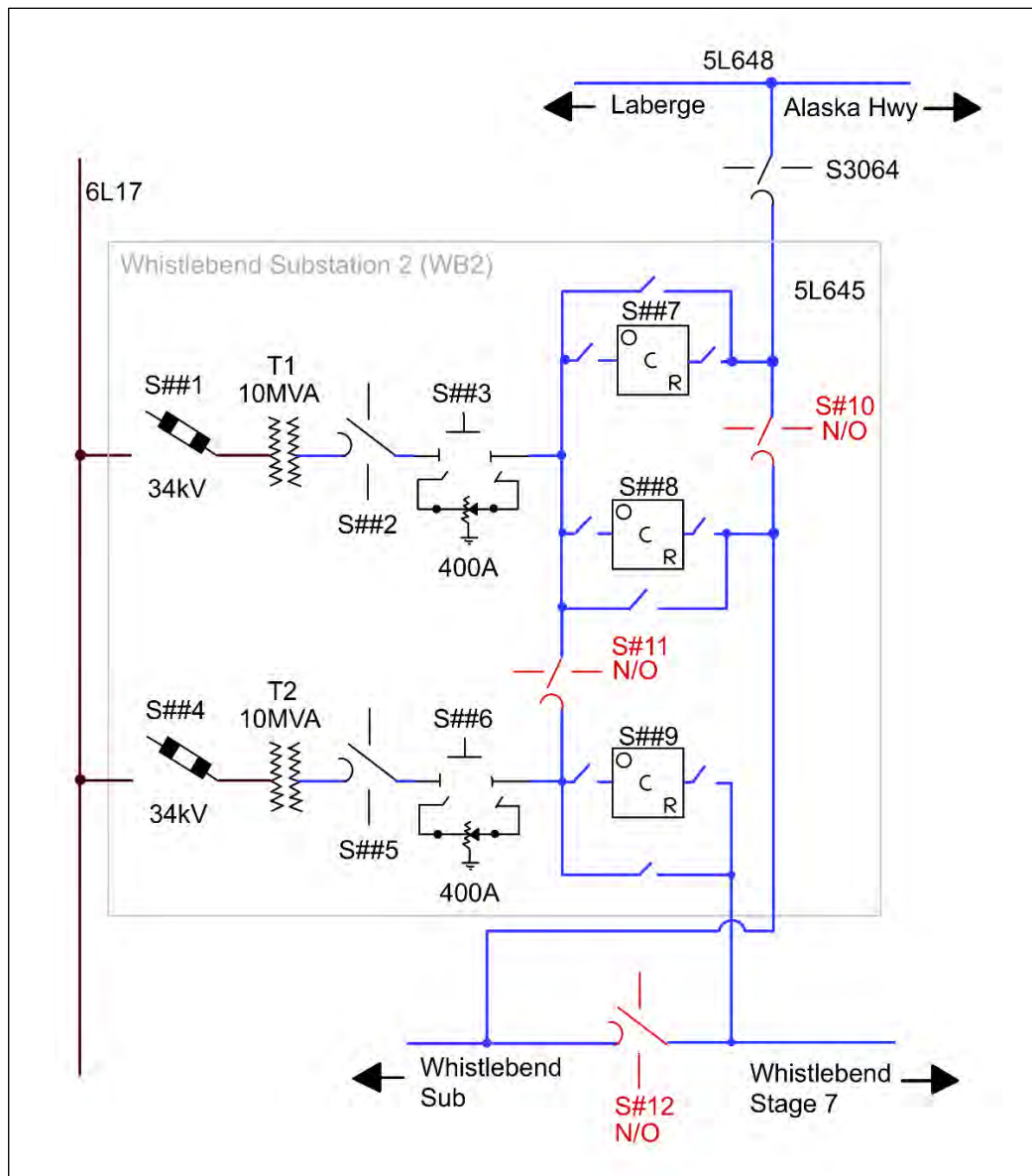


Figure 1: Whistlebend Substation 2 (WB2)

4.1.3 Additional System Improvement Requirements

In order to connect Whistlebend Substation 2 to the existing North 25kV system, the following switch points would be utilized:

- A recloser connecting WB2 Feeder 1 to 5L648 towards the highways (labelled as “S##7” in Figure 1)
- A recloser connecting WB2 Feeder 2 to Whistlebend Stage 7 (labelled as “S##9” in Figure 1)
- A recloser connecting WB2 Feeder 3 to serve as hot spare for Whistlebend Substation (labelled as “S##8” in Figure 1).

A comprehensive set of the switching devices required is displayed in Figure 1.

4.1.4 Contingency Operation

The proposed Whistlebend Substation 2 fully addresses the 2025 loading requirements for both of the contingency scenarios identified in Section 3. In Contingency scenario 1 (where the North 25kV system loses Laberge T1), WB2 will pick-up Laberge's load on its transformer T1 via new S##7 and back-feeding through Laberge's feeder breaker S3600 on 5L648. A possible switching program to achieve this is as follows: Isolate Laberge T1 using gang-switch S8302 and close-in the N/O breaker S3600.

In Contingency scenario 2 (where the North 25kV system loses Whistlebend T1 and T2 due to a primary bus outage), WB2 will pick up Whistlebend's load via Feeder 3. A possible switching program to achieve this is as follows: Isolate Whistlebend T1 and T2 using the transformer disconnects, close-in N/O switch S3434, and feed Whistlebend Substation from S##8 at WB2.

The loading on all major substation equipment during normal system configuration and during both contingencies is presented below in Table 1. As shown, during 2025 peak system loading and the N-1 contingencies, all equipment will be operating within manufacturer recommended limits.

Asset Description	Loading Limit	Loading during Regular Operation	Loading during Contingency 1	Loading during Contingency 2
LB Transformer T1 (3516)	10MVA	2.109MVA	0MVA	8.907MVA
LB Regs (R50, R51, R52)	400A	48A	0A	206A
LB Reclosers S3600	630A	2A	48A	158A
LB Reclosers S8306	400A	47A	48A	48A
WB Transformer T1 (458)	10MVA	3.861MVA	3.864MVA	0MVA
WB Transformer T2 (456)	10MVA	5.873MVA	5.875MVA	0MVA
WB Regs (R107, R108, R109)	400A	137A	138A	0A
WB Regs (R110, R111, R112)	400A	90A	90A	0A
WB Recloser S3431	630A	15A	15A	12A
WB Recloser S3432	630A	75A	75A	77A
WB Recloser S3433	630A	137A	138A	139A
WB Recloser S3434	630A	0A	0A	231A
WB2 Transformer T1	10MVA	6.571MVA	8.922MVA	8.926MVA
WB2 Transformer T2	10MVA	2.535MVA	2.536MVA	3.565MVA
WB2 Regs (on T1)	400A	156A	208A	207A
WB2 Regs (on T2)	400A	59A	59A	82A
WB2 Recloser 1	630A	0A	0A	207A
WB2 Recloser 2	630A	156A	208A	0A
WB2 Recloser 3	630A	59A	59A	82A

Table 1: Modelled system loading if the proposed WB2 substation is constructed (new equipment in bold)

4.1.5 System Voltage Improvement

Voltage levels at various locations throughout the system, including substation equipment and end-of-line customers are present in Appendix A. Overall, the system would experience a 7.22% voltage improvement across the North 25kV substations and a 0.5% voltage improvement for End-of-Line (EOL) customers compared to how the current system configuration would perform with 2025 peak loading levels.

4.1.6 Estimated Costs

Estimated relative costing for this option totaled to \$1,753,772. The cost breakdown is included in Appendix B.

NOTE: Costs for the construction of this substation were calculated relatively to the other options (as described in Section 3.4) and are used for comparison, not as a comprehensive total cost for construction of this solution.

4.2 Option B: Laberge Upgrade & Takhini Hot Springs Road Substation (TK1)

4.2.1 Overview

This solution involves a 2-part approach to meeting the desired system capabilities: upgrading Laberge Substation and constructing a new 10MVA substation near the intersection of Takhini Hot Springs Road and Klondike Highway North. The new substation will service all of the 25kV System on Alaska Highway and Klondike Highway north of Whitehorse. This area was previously serviced by Laberge Substation and will offload approximately 6MW of loading from Laberge, while improving the voltage levels along the highway and lowering the conductor resistive losses along 6L17. Upgrades to the Laberge substation will focus around a new 20MVA transformer to replace the existing 10MVA.

4.2.2 Equipment/Apparatus Requirements

To fully meet the expected 2025 system requirements, this solution proposes the addition of a new substation TK1 and upgrades to the existing Laberge Substation. At TK1, there would be a single 10MVA transformer, paired with a set of 400A regulators. This regulator would then feed a single 630A SCADA-controlled recloser that would feed both the North Alaska Highway and the North Klondike Highway. An SLD of TK1 is shown below in Figure 2.

The scope of the upgrades to Laberge Substation include replacing the existing T1 with a 20MVA transformer, replacing the existing regulators with 578A rated models, and upgrading bus-bars and gang-switches as required to facilitate the output of 20MVA from this site. During regular operation, Laberge is only anticipated to be loaded at ~2MVA and mainly servicing the Crestview area, as there would be more system loss if this substation was to feed any of the Whistlebend subdivision. This new transformer would therefore be lightly loaded, except during contingency situations. A summary of the large apparatus required for this proposal is listed below:

For TK1:

- 1 x 10MVA 34.5/25kV Transformer
- 3 x 400A 25kV Regulators
- 1 x 630A 25kV Reclosers

For Laberge:

- 2 x 20MVA 34.5/25kV Transformer (1 for Laberge, 1 spare)
- 3 x 578A 25kV Regulators

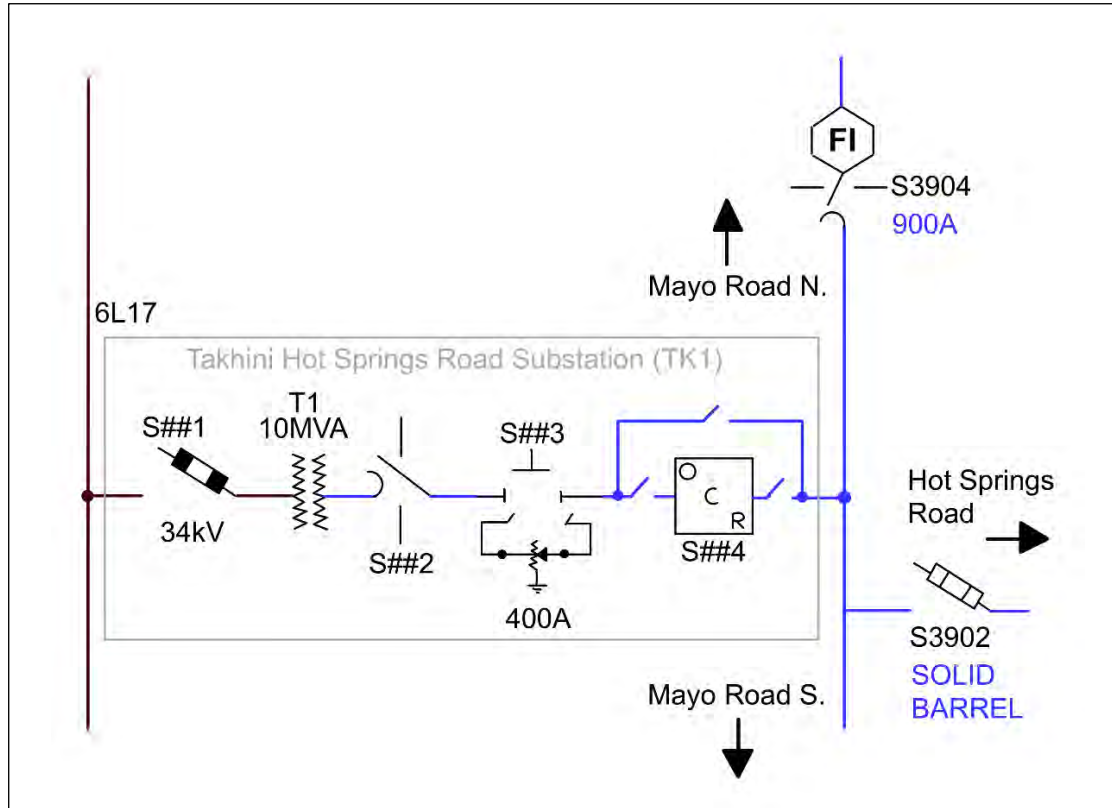


Figure 2: Takhini Hot Springs Road Substation (TK1)

4.2.3 Additional System Improvement Requirements

As this proposal already includes upgrades to resolve the expected overloading on the Laberge regulators, the only other system improvements will be the following additional switching points:

- A recloser connecting TK1 to the 5L648 along Klondike Highway North (labelled as "S##4" in Figure 2.)
- An inline N/O switch on 5L645 just north of the junction with 5L648. This will keep the hot-spare tie-in between Laberge and Whistlebend, while isolating the highways that will be supplied by TK1.

4.2.4 Contingency Operation

The proposed combination of a new Takhini Hot Springs Road Substation and upgrades to Laberge Substation would fully meet the expected loading requirements for N-1 contingency coverage in 2025. During Contingency Scenario 1 (loss of 34.5/25kV transformer at Laberge), the regular load serviced by Laberge would be transferred to Whistlebend Substation via recloser S3434. One possible switching operation to achieve this, would be to isolate Laberge T1 and then back-feed Laberge substation from Whistlebend's S3434 and feed through S3600 and continue to supply the Crestview area through S8306.

In the event of Contingency 2 (loss of primary bus at Whistlebend), the reverse of the Contingency 1 restoration will occur. Laberge will source the power for Whistlebend subdivision and feed through S3600 and feed into Whistlebend Substation through S3434 and the tie-in point at the edge of Stage 7. A possible switching program to achieve this would be: Isolate T1 and T2 at Whistlebend, close-in N/O S3434 to connect all 4 reclosers at Whistlebend, close-in stage-7 tie-in, close-in S3064 to tie 5L645 and 5L648 together, and close-in recloser S3600 at Laberge. The loading on all major substation equipment during normal system configuration and during both contingencies is presented below in Table 2. As shown, during 2025 peak system loading and the N-1 contingencies, all equipment will be operating within manufacturer recommended limits.

Asset Description	Loading Limit	Loading during Regular Operation	Loading during Contingency 1	Loading during Contingency 2
LB Transformer T1 (3516)	20MVA	2.108MVA	0MVA	14.788MVA
LB Regs (R50, R51, R52)	578A	48A	0A	335A
LB Reclosers S3600	630A	2A	47A	291A
LB Reclosers S8306	400A	47A	47A	49A
WB Transformer T1 (458)	10MVA	6.456MVA	6.458MVA	0MVA
WB Transformer T2 (456)	10MVA	5.914MVA	8.104MVA	0MVA
WB Regs (R107, R108, R109)	400A	134A	185A	0A
WB Regs (R110, R111, R112)	400A	146A	147A	0A
WB Recloser S3431	630A	15A	15A	15A
WB Recloser S3432	630A	132A	132A	51A
WB Recloser S3433	630A	133A	135A	137A
WB Recloser S3434	630A	1A	50A	203A
TK1 Transformer T1	10MVA	6.650MVA	6.648MVA	6.648MVA
TK1 Regs (on T1)	400A	148A	148A	148A
TK1 Recloser 1	630A	108A	108A	108A

Table 2: Modelled system loading if the proposed TK1 substation is constructed and Laberge is upgraded (new equipment in bold)

4.2.5 System Voltage Improvement

Overall, the North 25kV system would experience a 9.35% voltage improvement across the 3 34.5/25kV substations if compared against how the current system configuration would perform with 2025 peak loading. End-of-Line customers are expected to have 1.9% voltage improvement as well.

4.2.6 Estimated Costs

Estimated relative costs for this option totaled to \$2,005,650. The cost breakdown is included in Appendix B.

NOTE: Costs for the construction of this substation were calculated relatively to the other options (as described in Section 3.4) and are used for comparison, not as a comprehensive total cost for construction of this solution.

4.3 Option C: Whistlebend Substation 2 (WB2) & Takhini Hot Springs Road Substation (TK1)

4.3.1 Overview

Similar to Option B, this option also takes a 2-part approach to meet the desired system capabilities, however this option involves the construction of 2 new substations: Takhini Hot Springs Road Substation (TK1) and Whistlebend Substation 2 (WB2). Identical to Option B, TK1 would be a 10MVA substation at the intersection of the Alaska Highway and Takhini Hot Springs Road. This substation would service the Alaska Highway and Klondike Highway sections of the North 25kV system, therefore offloading approximately 6MW from Laberge Substation. If selected, this option would involve the construction of WB2 with only a single 10MVA transformer and would be located near stage 7 of the Whistlebend Subdivision (same location as WB2 in Option A). This substation would service stages 4-7 of the Whistlebend subdivision during regular operation. This option places both substations close to the load-centres they would serve and would decrease electrical system losses as a whole.

4.3.2 Equipment/Apparatus Requirements

To be able to provide adequate power with 2025 peak loading levels and expected system expansions, this option proposes the construction of two new substations: TK1 and WB2. At TK1 (the same as proposed in Option B), there would be a single 10MVA transformer, paired with a set of 400A regulators and a single 630 SCADA-controlled recloser. A simplified model of TK1 is shown above in Figure 2.

The scope of equipment required for WB2 would be similar to TK1 with the addition of a second recloser. This substation would require a 10MVA transformer, 400A regulators for each phase and 2 separate 630A SCADA-controlled reclosers. One of the reclosers would feed directly into the Whistlebend subdivision through stage 7, while the other breaker would connect to 5L648 and would be a hot-spare to support either Laberge or Whistlebend in the event of an outage. A summary of the large apparatus required for this proposal is listed below:

For TK1:

- 1 x 10MVA 34.5/25kV Transformer
- 3 x 400A 25kV Regulators
- 1 x 630A 25kV Reclosers

For WB2:

- 1 x 10MVA 34.5/25kV Transformer
- 3 x 400A 25kV Regulators
- 2 x 630A 25kV Reclosers

Additionally, the regulators installed at Laberge Substation (R50, R51, R52) are still anticipated to be overloaded during Contingency Scenario 2, therefore this apparatus will require an upgrade. The next standard size of regulator AEY utilizes is rated for 400A and will adequately meet the expected loading on this device.

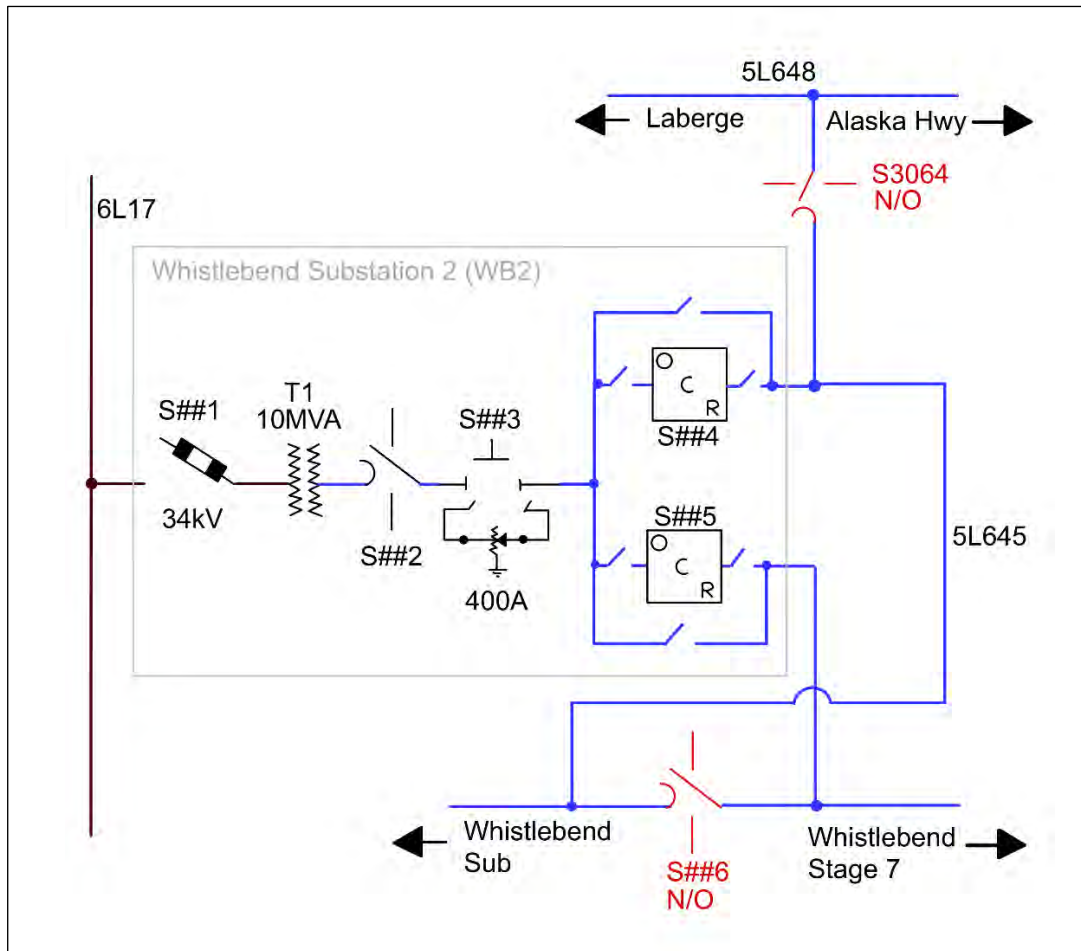


Figure 3: Whistlebend Substation 2 - 10MVA Option (WB2)

4.3.3 Additional System Improvement Requirements

This proposal includes the addition of 2 new substations, therefore it does require a few more switching points to be added than the other options provided:

- A recloser connecting TK1 to the 5L648 along Klondike Highway North (labelled as "S##4" in Figure 2.)
- Inline N/O switch on 5L645 just north of the junction with 5L648. This will keep the hot-spare tie-in between Laberge and Whistlebend, while isolating the highways that will be supplied by TK1.

- A recloser connecting WB2 to 5L648 (labelled as “S##4” in Figure 3.)
- A recloser connecting WB2 to Whistlebend Stage 7 (labelled as “S##5” in Figure 3.)

A comprehensive set of the switching devices required at WB2 is displayed in Figure 3.

4.3.4 Contingency Operation

The proposed combination of constructing a Takhini Hot Springs Road Substation and a new Whistlebend Substation 2 would fully meet the system requirements for 2025. In Contingency Scenario 1 (loss of 34.5/25kV transformer at Laberge), the load typically served by Laberge (~2MW in the Crestview area) would be picked-up by WB2. This would only require Laberge transformer to be isolated and then close-in S3064 to tie 5L648 and 5L645 together.

If the system was in Contingency Scenario 2, all of the typical Whistlebend load would need to be off-loaded to other substations. This could be most easily accomplished by using a combination of Laberge and WB2 to pick-up the stranded load. Laberge could feed into the Whistlebend Substation through S3434, while WB2 would continue to feed into stage 7 and could take on more of the Whistlebend load by moving the open point further downstream. The loading on all major substation equipment during normal system configuration and during both contingencies is presented below in Table 3. During 2025 peak system loading and the N-1 contingencies, all equipment would be operating within manufacturer recommended limits.

Asset Description	Loading Limit	Loading during Regular Operation	Loading during Contingency 1	Loading during Contingency 2
LB Transformer T1 (3516)	10MVA	2.213MVA	0MVA	9.043MVA
LB Regs (R50, R51, R52)	400A	50A	0A	204A
LB Reclosers S3600	630A	2A	49A	155A
LB Reclosers S8306	400A	48A	49A	49A
WB Transformer T1 (458)	10MVA	2.827MVA	2.827MVA	0MVA
WB Transformer T2 (456)	10MVA	5.930MVA	5.931MVA	0MVA
WB Regs (R107, R108, R109)	400A	134A	135A	0A
WB Regs (R110, R111, R112)	400A	64A	64A	0A
WB Recloser S3431	630A	14A	15A	15A
WB Recloser S3432	630A	49A	50A	0A
WB Recloser S3433	630A	134A	135A	137A
WB Recloser S3434	630A	0A	0A	152A
TK1 Transformer T1	10MVA	7.153MVA	7.153MVA	7.153MVA
TK1 Regs (on T1)	400A	159A	159A	159A
TK1 Recloser 1	630A	159A	159A	159A
WB2 Transformer T1	10MVA	3.563MVA	5.867MVA	5.787MVA
WB2 Regs (on T1)	400A	80A	132A	130A
WB2 Recloser 1	630A	80A	80A	130A
WB2 Recloser 2	630A	0A	52A	0A

Table 3: Modelled system loading if the proposed substations TK1 and WB2 are both constructed (new equipment in bold)

4.3.5 System Voltage Improvement

Overall, the North 25kV system would experience a 10.28% voltage improvement at the 3 34.5/25kV substations and a 2.0% voltage improvement for EOL customers if compared against how the current system configuration would perform with 2025 peak loading.

4.3.6 Estimated Costs

Estimated relative costs for this option totaled to \$1,831,086. The cost breakdown is included in Appendix B.

NOTE: Costs for the construction of this substation were calculated relatively to the other options (as described in Section 3.4) and are used for comparison, not as a comprehensive total cost for construction of this solution.

5. Decision Matrix

To facilitate a comparison of the 3 proposed solutions, a decision matrix was developed based on the expected system requirements and key criteria for the planning window. The key criteria that resulted from the previous study of the North 25kV system are eliminatory elements on the decision matrix. Therefore, if any solution does not at least fully address these criteria, the solution would be removed from the running. The remaining non-key criteria are ranking-only and therefore do not have a minimum required score for a solution to pass. A summary of the decision matrix as well as the legend explaining the ranking process are included below in Table 4 and Table 5.

				Solution A		Solution B		Solution C	
Criterion type	Criterion	Criterion Weight	Threshold Value	Rating	Score	Rating	Score	Rating	Score
Eliminatory	Additional Transformer Capacity	4	3	5	20	5	20	5	20
Eliminatory	Resolve Laberge Regulator Overload	4	3	4	16	4	16	4	16
Ranking-only	Improve System Voltage	2	3	2	4	4	8	4	8
Ranking-only	Ease of Switching/Operation	2	N/A	4	8	4	8	4	8
Ranking-only	Utilization of New Apparatus	3	N/A	4	12	2	6	4	12
Ranking-only	Project Cost	5	N/A	3	15	2	10	3	15
Totals:				75		68		79	

Table 4: Decision Matrix

Legend	
1	Does not address criterion (<50% of criteria)
2	Does not fully address criterion (>75% of criteria)
3	Fully addresses criterion (>95% of criteria)
4	Exceeds criterion (>125% of criteria)
5	Greatly exceeds criterion (>150% of criteria)

Table 5: Legend for Decision Matrix

6. Recommendation

Each proposed solution was individually evaluated against equipment loading limits, system voltage requirements, and restoration-switching guidelines. Additionally, among all of the proposed solutions, a comparative cost analysis was performed based on previous completed substation projects and the main expected costs for each design. After inputting the results into a decision matrix and totaling the data, it was determined that Solution C is the recommended solution to meet the North 25kV system requirements. Solution B will include the construction of a new 10MVA substation on the north-west side of Whistlebend Subdivision, as well as the construction of a new 10MVA substation near the junction of Takhini Hot Springs Road and Klondike Highway North. This solution will meet all the key requirements and will well-position the North 25kV for future expansions beyond the 6-year planning window.

Appendix A: CYME Modelling Data

		Expected Loading									
		Loading Limit		Status Quo		Solution A (WB2)		Solution B (TK1 & Laberge Upgrade)		Solution C (TK2 & WB2)	
Asset Description		kVA	Amps	kVA	Volts (p.u.)	kVA	Volts (p.u.)	kVA	Volts (p.u.)	kVA	Volts (p.u.)
Regular Operation	LB Transformer T1 (3516)	10000	N/A	8847	0.89	2109	0.911	2108	0.936	2213	0.935
	LB Regulators (R50, R51, R52)	N/A	200	8651	0.9657	2098	1.002	2098	1.006	2202	1.028
	LB Recloser S3600	N/A	630	6636	0.957	84	1.002	84	1.006	84	1.028
	LB Recloser S8306	N/A	400	2016	0.957	2014	1.002	2014	1.006	2118	1.028
	WB Transformer T1 (458)	10000	N/A	6467	0.888	3861	0.888	6456	0.914	2827	0.925
	WB Transformer T2 (456)	10000	N/A	5920	0.888	5873	0.888	5914	0.914	5930	0.917
	WB Regulators (T2)	N/A	400	5833	0.0976	5786	0.977	5831	1.006	5848	1.009
	WB Regulators (T1)	N/A	400	6360	0.977	3825	0.983	6356	1.006	2808	1.017
	WB Recloser S3431	N/A	630	638	0.977	637	0.983	637	1.006	637	1.017
	WB Recloser S3432	N/A	630	5723	0.977	3187	0.983	5719	1.006	2171	1.017
	WB Recloser S3433	N/A	630	5788	0.976	5786	0.977	5786	1.006	5848	1.009
	WB Recloser S3434	N/A	630	45	0.976	0	0.977	45	1.006	0	1.009
	New Sub T1	10000	N/A	0	N/A	6571	0.894	6650	0.97	3563	0.929
	New Sub T2	10000	N/A	0	N/A	2535	0.903	0	N/A	7153	0.97
	New Sub Reg 1	N/A	400	0	N/A	6652	0.984	6564	1.026	3534	1.022
	New Sub Reg 2	N/A	400	0	N/A	2520	0.993	0	N/A	7058	1.028
	New Sub Recloser 1	N/A	630	0	N/A	0	0.984	6564	1.025	3507	1.028
	New Sub Recloser 2	N/A	630	0	N/A	6652	0.984	0	N/A	0	1.028
	New Sub Recloser 3	N/A	630	0	N/A	2520	0.993	0	N/A	7058	1.022
Contingency 1*	LB Transformer T1 (3516)	10000	N/A	0	N/A	0	N/A	0	N/A	0	N/A
	LB Regulators	N/A	200	0	N/A	0	N/A	0	N/A	0	N/A
	LB Recloser S3600	N/A	630	2016	0.92	2016	0.964	2014	0.995	2119	1.008
	LB Recloser S8306	N/A	400	2345	0.938	2016	0.964	2014	0.995	2119	1.008
	WB Transformer T1 (458)	10000	N/A	10128	0.853	3864	0.884	6458	0.909	2827	0.922
	WB Transformer T2 (456)	10000	N/A	11057	0.859	5875	0.89	8104	0.902	5931	0.915
	WB Regulators (T2)	N/A	400	10709	0.938	5788	0.973	7942	0.992	5848	1.006
	WB Regulators (T1)	N/A	400	9846	0.944	3826	0.979	6357	1	2808	1.015
	WB Recloser S3431	N/A	630	638	0.944	637	0.979	637	1	637	1.015
	WB Recloser S3432	N/A	630	9208	0.944	3189	0.979	5719	1	2171	1.015
	WB Recloser S3433	N/A	630	2345	0.938	5788	0.973	5786	0.992	5848	1.006
	WB Recloser S3434	N/A	630	8364	0.938	0	0.973	2155	0.992	0	1.006
	New Sub T1	10000	N/A	0	N/A	8922	0.883	6648	0.97	5867	0.92
	New Sub T2	10000	N/A	0	N/A	2536	0.899	0	N/A	7153	0.97
	New Sub Reg 1	N/A	400	0	N/A	8719	0.971	6564	1.026	5845	1.012
	New Sub Reg 2	N/A	400	0	N/A	2520	0.989	0	N/A	7058	1.027
	New Sub Recloser 1	N/A	630	0	N/A	0	0.971	6564	1.025	3507	1.012
	New Sub Recloser 2	N/A	630	0	N/A	8719	0.971	0	N/A	2311	1.027
	New Sub Recloser 3	N/A	630	0	N/A	2520	0.989	0	N/A	7059	1.027

Contingency 2	LB Transformer T1 (3516)	10000	N/A	21707	0.826	8907	0.889	14788	0.916	9043	0.912
	LB Regulators	N/A	200	20186	0.888	8709	0.978	14584	1.007	8840	1.003
	LB Recloser S3600	N/A	630	18170	0.888	6693	0.978	12570	1.001	6722	1.003
	LB Recloser S38306	N/A	400	2017	0.888	2015	0.978	2015	1.007	2119	1.003
	WB Transformer T1 (458)	10000	N/A	0	N/A	0	N/A	0	N/A	0	N/A
	WB Transformer T2 (456)	10000	N/A	0	N/A	0	N/A	0	N/A	0	N/A
	WB Regulators (T2)	N/A	400	0	N/A	0	N/A	0	N/A	0	N/A
	WB Regulators (T1)	N/A	400	0	N/A	0	N/A	0	N/A	0	N/A
	WB Recloser S3431	N/A	630	521	0.851	638	0.962	637	0.979	637	0.986
	WB Recloser S3432	N/A	630	3189	0.851	3190	0.962	2172	0.979	0	0.986
	WB Recloser S3433	N/A	630	5790	0.851	5789	0.962	5787	0.979	5849	0.986
	WB Recloser S3434	N/A	630	9500	0.851	9617	0.962	8596	0.979	6486	0.986
	New Sub T1	10000	N/A	0	N/A	8926	0.888	6648	0.97	5787	0.925
	New Sub T2	10000	N/A	0	N/A	3565	0.902	0	N/A	7153	0.972
	New Sub Reg 1	N/A	400	0	N/A	8717	0.976	6564	1.025	5709	1.017
	New Sub Reg 2	N/A	400	0	N/A	3534	0.992	0	N/A	7058	1.027
	New Sub Recloser 1	N/A	630	0	N/A	8717	0.976	6564	1.025	5709	1.017
	New Sub Recloser 2	N/A	630	0	N/A	0	0.976	0	N/A	0	1.027
	New Sub Recloser 3	N/A	630	0	N/A	3534	0.992	0	N/A	7059	1.027

End of Line Voltage:	93.2%	93.7%	95.1%	95.2%
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Appendix B: Cost Estimates

Categories:	Selkirk (Inflated) Cost:	Option A		Option B		Option C	
		Multiplier	Cost	Multiplier	Cost	Multiplier	Cost
<u>Contractor/Non-Stock</u>							
Surveying	\$13,728	1.5	\$20,592	1	\$13,728	2	\$27,456
<u>Overhead (Stock) Material</u>							
Regulator (400A)	\$29,326	9	\$263,933	3	\$87,978	9	\$263,933
Regulator (578A)*	\$40,292	0	\$0	3	\$120,876	0	\$0
<u>Overhead (Non-Stock) Material</u>							
Timbers	\$9,360	2.5	\$23,400	1	\$9,360	2	\$18,720
<u>Undergorund (Non-Stock) Material</u>							
38kV Reclosers	\$24,750	3	\$74,250	1	\$24,750	3	\$74,250
10MVA 34.5/25kV Transformer	\$189,357	2	\$378,714	1	\$189,357	2	\$378,714
20MVA 34.5/25kV Transformer*	\$500,000	0	\$0	2	\$1,000,000	0	\$0
<u>Contractor Work</u>							
Oil Containment	\$39,624	2	\$79,248	1	\$39,624	2	\$79,248
Resistivity Testing	\$7,097	1	\$7,097	1	\$7,097	2	\$14,194
Contractor	\$86,522	1.5	\$129,783	1	\$86,522	2	\$173,044
<u>Engineering Consultant</u>							
Land Developing and Permits	\$5,778	1	\$5,778	1	\$5,778	2	\$11,556
<u>AEY Overhead Construction</u>							
Crew Overhead Construction	\$75,966	2	\$151,932	1.5	\$113,949	2	\$151,932
<u>AEY Underground Construction</u>							
Crew Underground Work	\$12,839	2	\$25,678	1.5	\$19,258	2	\$25,678
<u>Contractor Civil Work</u>							
Supply 3/4" Crush	\$53,026	2	\$106,053	1	\$53,026	2	\$106,053
Supply 6" Minus	\$10,997	2	\$21,994	1	\$10,997	2	\$21,994
Ducts and Trench	\$16,680	2	\$33,359	1	\$16,680	2	\$33,359
Concrete Cast in Place	\$23,706	2	\$47,412	1	\$23,706	2	\$47,412
Pre-Cast Vaults	\$16,068	2	\$32,136	1	\$16,068	2	\$32,136
Grounding Grid	\$13,284	2	\$26,568	1	\$13,284	2	\$26,568
<u>Equipment Commissioning</u>							
Techs	\$33,977	2	\$67,954	1	\$33,977	2	\$67,954
<u>Project Lead</u>							
EA	\$13,358	1.5	\$20,037	1.5	\$20,037	2	\$26,716
<u>Project Engineering</u>							
Engineering	\$18,118	1.5	\$27,177	1.5	\$27,177	2	\$36,236
<u>Contractor Lead</u>							
Contractor Lead	\$12,955	2	\$25,911	2	\$25,911	2	\$25,911
<u>AEY Drafting</u>							
Drafting	\$6,512	1.5	\$9,769	1	\$6,512	2	\$13,025
<u>Substation Connection Costs</u>							
Connection Costs*	N/A	N/A	\$175,000	N/A	\$40,000	N/A	\$175,000
		Totals:		\$1,753,772		\$2,005,650	
						\$1,831,086	

*Equipment included in the scope of any of these options that was not included Selkirk's has been estimated using manufacturer quotes and current AEY Engineering estimating tools

September 28, 2023

AEY-YUB-060

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-060

Reference: 2023-24 GRA, Business Case #29 – Old Crow Voltage Improvement, PDF pages 91-97, paragraph 2

Issue: Capital expenditures (Distribution Improvements)

Quote: During a 2021 system study for the addition of a new health center and 10 plex in Old Crow, it was noted that, after the addition, the voltage would drop below acceptable levels (0.95 p.u.).

Table 1: Voltage Level Analysis

Existing Worst Case Voltage Levels	Va	Vb	Vc
(p.u.)	0.914	0.921	0.933

Preamble: In tables 3 and 7 of this business case, AEY provides existing conditions and worst voltage A, B and C under various alternative solutions. Only Table 7 indicates an existing voltage that is below the acceptable level (0.95 p.u.).

Request:

- (a) Please substantiate AEY's claim that the Old Crow Voltage Improvement project will resolve any existing voltage below the acceptable level (0.95 p.u.) by providing further information addressing the Board's observation.
- (b) Please provide the comparative cost-benefit analysis prepared for each of the seven alternatives examined.

Response:

- (a) Business Case #29 has been re-evaluated to help clarify the data used and the decisions arrived at. Please refer to AEY-YUB-60(a) Attachment 1. Some of the

September 28, 2023

AEY-YUB-060

voltage values and evaluated alternatives may differ; however, the recommended solutions remain the same. Differences in voltage values are due to model updates and load growth. The original Business Case #29 has been completed with 2021 data, whereas the re-evaluated Business Case utilizes 2022 and 2023 data. Please refer to AEY-YUB-060(a) Attachment 2 for the updated data. The recommendations from the original Business Case and the re-evaluated Business Case remain the same.

- (b) Costs have been added to alternatives listed in AEY-YUB-60(a) Attachment 1. The recommended alternatives best meet the driver needs at the least cost.



2023-2024 General Rate Application (GRA)

Old Crow Voltage Improvement

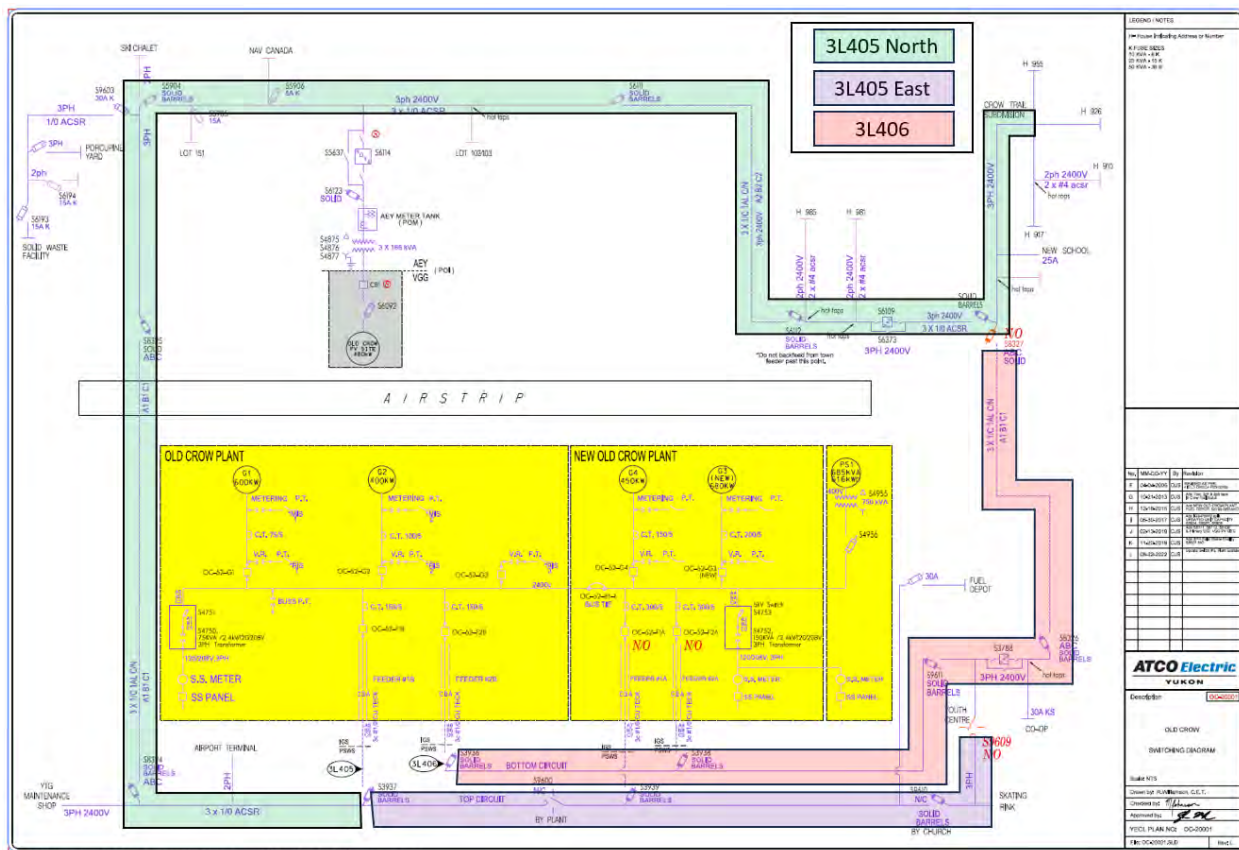
2023-2024 Business Case #29 (Updated)

Executive Summary

1. Old Crow has continued to see an increase in load growth year after year. New peak loads are straining the Old Crow system to a point where AEY cannot reliably provide electricity that is within voltage standards greater than 0.95 Vpu. This deficiency is caused by long distances between generation and customers, size of primary conductors, and the overall primary system voltage.

Background

Figure 1: Old Crow SLD



Summer

Two scenarios were analyzed in CYME during summer loading using historical data between July 1, 2023, and July 6, 2023; Scenario 1 represents Battery Energy Storage System (BESS)-only generation and Scenario 2 represents Photo Voltaic (PV) array

generation with BESS charging. These dates were chosen so that the Old Crow system would be diesel-off (i.e., the Old Crow system is solely powered by the PV array and battery).

Scenario 1: BESS-only generation

Historical data shows a peak in BESS generation on July 3, 2023, at 10:20 pm equaling 241 kW. Since the BESS is connected at the plant, and the modelling goal is confirming voltage levels and not fault current, this scenario was modeled in CYME with all generators connected with voltage set at 1.01 Vpu (BESS set point), and the model loaded at 33 percent (to match measured BESS output).

Note - The BESS has the capability to generate up to 685 kW of power which is why all generators were left active in the model.

Scenario 2: PV generation with BESS charging

The peak load on the system – less BESS charging – was found on July 3, 2023, and equaled 322 kW. To model this scenario a generator was placed at the PV array site, all diesel generators at the main plant were disconnected, the BESS was set to charge at 95 kW, and the model was loaded at 44 percent. The voltage setpoint for the PV site was set to 1.05 Vpu, resulting in a 1.01Vpu measurement at the plant bus (BESS setpoint voltage).

No low voltage issues were found when analyzing the Old Crow system during summer conditions.

Winter

The CYME model is run at 100 percent which is equal to peak winter loading.

Table 1: Old Crow Voltages

Study Area	Summer Loading – Scenario 1 (Worst Vpu)	Summer Loading – Scenario 2 (Worst Vpu)	Winter Loading – No PV (Worst Vpu)
3L406	A – 0.977 B – 0.970 C – 0.976	A – 0.968 B – 0.957 C – 0.961	A – 0.928 B – 0.904 C – 0.923
3L405 North	A – 0.974 B – 0.976 C – 0.977	A – 0.984 B – 0.985 C – 0.986	A – 0.918 B – 0.923 C – 0.927
3L405 East	A – 0.995 B – 0.996 C – 0.993	A – 1.002 B – 1.001 C – 0.995	A – 0.984 B – 0.986 C – 0.978

Voltages that fall below AEY standards were found on 3L406 and 3L405 North. Upgrades must be completed to fix the low voltages issues.

Project Description

This project includes reconductoring two main feeders in Old Crow: 3L406 and 3L405 East. Existing conductor sizes on 3L406 range from #4 ACSR to #6 ACSR and will be reconducted between the Old Crow diesel plant and recloser S3788 with 1/0 ACSR. The 3L405 East feeder that services customers on the East side of the Old Crow Diesel Plant is also a combination of #4 ACSR and #6 ACSR that will be reconducted to 1/0 ACSR between S3937 and S9609. This also includes reconductoring the tap to the Old Crow skating rink to 1/0 ACSR. Furthermore, a new regulator will be installed near the Old Crow PV Site as seen in Alternative 1.1.

Project Schedule and Cost

**Table 2: Project Schedule and Cost
(\$000)**

Date		Cost
2023	Regulator Addition	\$710
2024	Reconductor 3L406 and 3L405 East	\$464
Total		\$1,174

Business Drivers and Benefits

The main driver behind the regulator addition and reconductoring is to raise the voltage at customer's service points to a level that is at or above AEY's minimum supply voltage standards. Not only will the voltage levels be within standard after the completion of the upgrades, but system capacity will also be increased due to the infrastructures capabilities to provide energy at adequate voltage levels. This will ensure that growth in Old Crow can continue, and electricity demand can be met.

Evaluation of Viable Alternatives

There are three problems within the Old Crow system that are addressed in the alternatives below:

1. Low voltage on 3L405 North during Winter loading,
2. Low voltage on 3L406 during Winter loading, and
3. Capacity on 3L405 East.

For modelling each alternative, the modification specified in each option was added, with no changes to system loading. The new worst EOL voltage was recorded.

To determine an approximate load growth capacity, load was added until the worst end-of-line voltage hit 0.95 Vpu.

1. Alternatives for Low Voltage on 3L405 North

Alternative 1.1 - Regulator Bank on 3L405 North

Project Scope: \$710,000

- 100A 2.4kV Regulator Bank

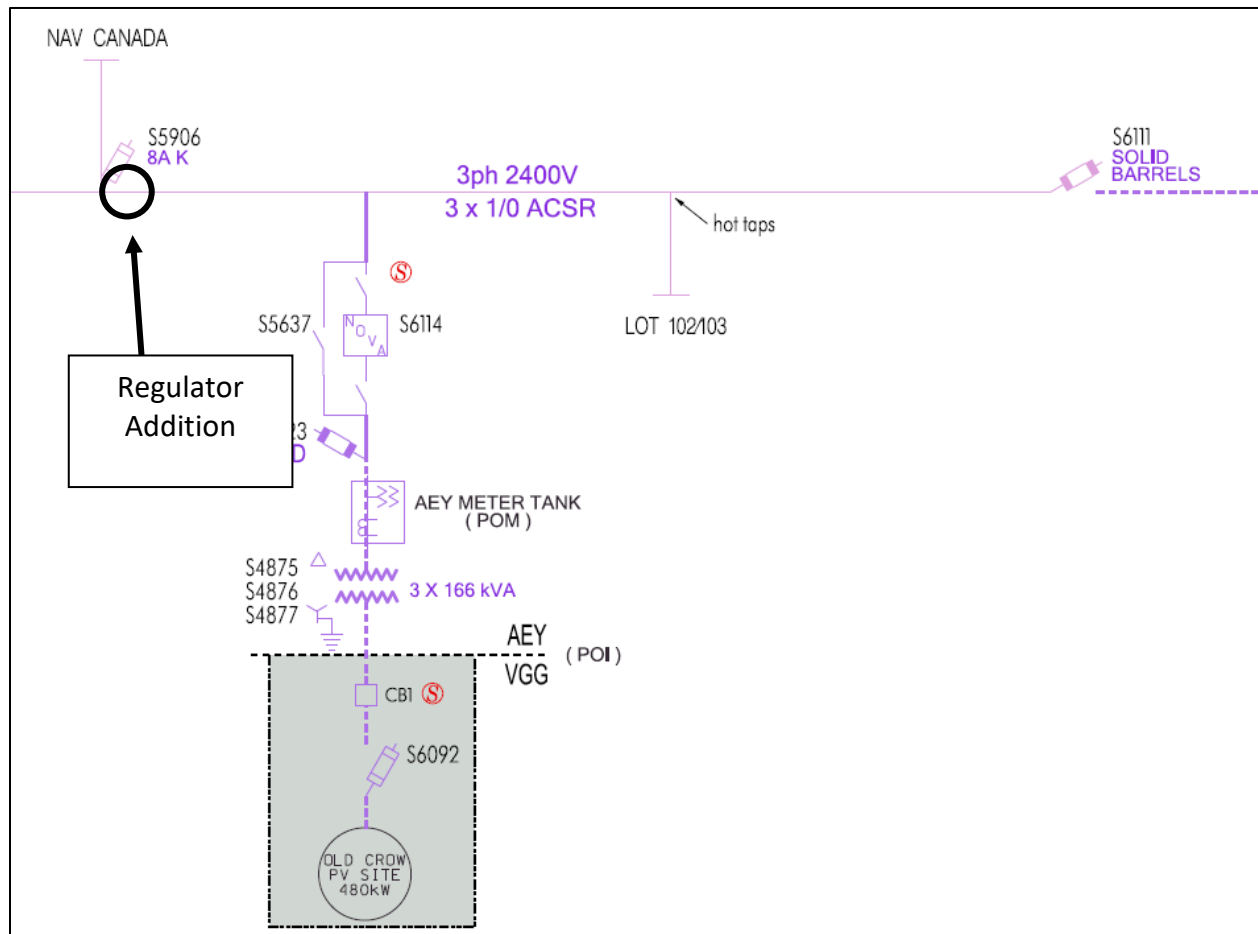
Regulator location was determined using two criteria:

1. Locating a point near where voltages on 3L405 North begin to fall below AEY standard during peak Winter loading, and
2. Allows for the largest increase in end-of-line load growth.

Table 3: Alternative 1.1 Voltages

	Existing (V pu)	Alternative 1.1 (V pu)
Worst Voltage on 3L405 North	A – 0.918 B – 0.923 C – 0.927	A – 0.994 B – 0.994 C – 1.000
End of Line Load Growth Capacity	0 kW	80 kW

Figure 2: Alternative 1.1 SLD



Alternative 1.2 - Reconductor with Regulator Bank on 3L405 North

Project Scope: \$787,000

- 100A 2.4kV Regulator Bank (\$710,000)
- ~310m of 4/0 UG AL (\$77,000)

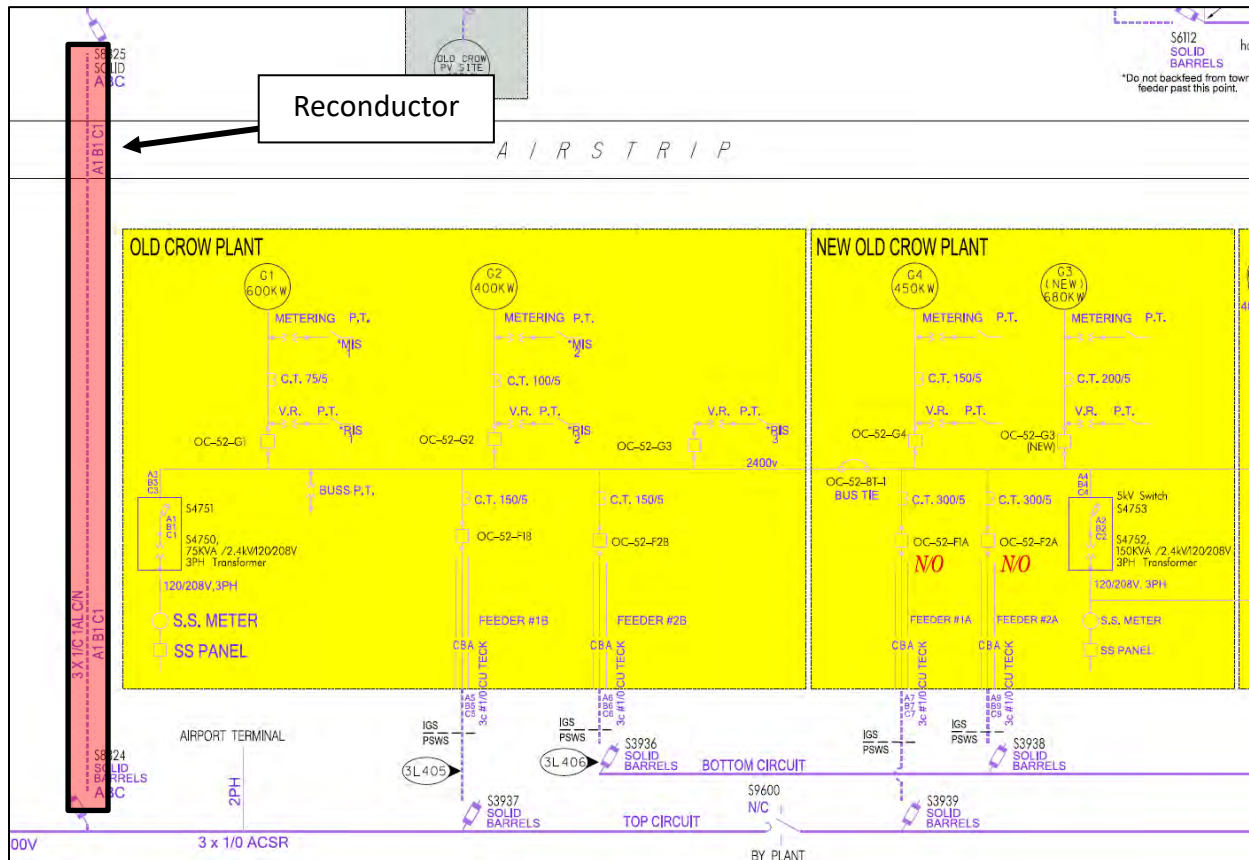
Regulator location is the same as in Alternative 1.1. The existing 1C1 AL underground cable between S8324 and S8325 is a bottle neck for voltage drop. By upgrading the cable size to 4/0 AL, capacity on 3L405 can be further increased.

Reconductoring this section of line alone is not sufficient to address the low voltage issues on 3L405 North.

Table 4: Alternative 1.2 Voltages

	Existing (V pu)	Alternative 1.1 (V pu)	Alternative 1.2 (V pu)
Worst Voltage on 3L405 North	A – 0.918 B – 0.923 C – 0.927	A – 0.994 B – 0.994 C – 1.000	A – 0.992 B – 0.996 C – 1.000
End of Line Load Growth Capacity	0kW	80kW	100kW

Figure 3: Alternative 1.2 SLD



2. Alternatives for Low Voltage on 3L406

Alternative 2.1 - Regulator Bank on 3L406

Project Scope: \$710,000

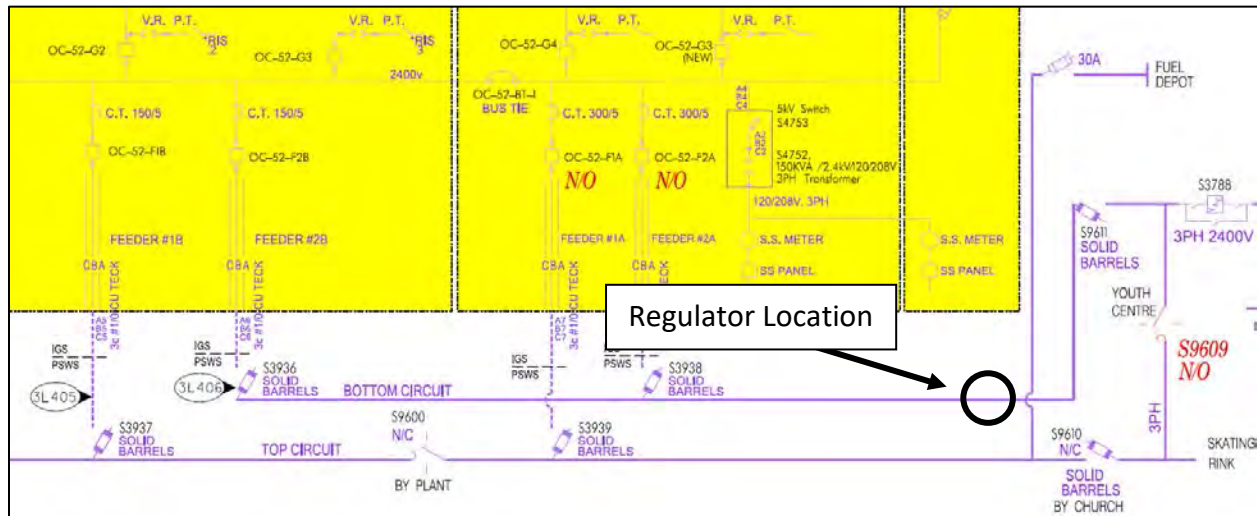
- 100A 2.4kV Regulator Bank

Regulator location was determined in the same manner as in Alternative 1.1.

Table 5: Alternative 2.1 Voltages

	Existing (V pu)	Alternative 2.1 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 1.004 B – 0.987 C – 1.002
End of Line Load Growth Capacity	0 kW	75 kW

Figure 4: Alternative 2.1 SLD



Alternative 2.2 - Reconductor 3L406

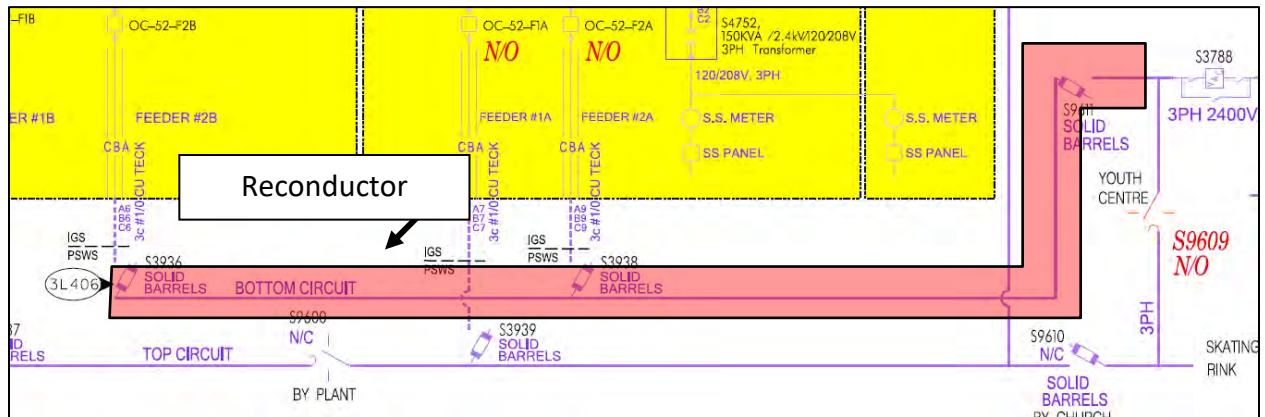
Project Scope: \$232,000

- ~940m of 1/0 ACSR, replacing a mixture of #4 and #6 ACSR

Table 6: Alternative 2.2 Voltages

	Existing (V pu)	Alternative 2.2 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 0.968 B – 0.961 C – 0.962
End of Line Load Growth Capacity	0 kW	35 kW

Figure 5: Alternative 2.2 SLD



Alternative 2.3 - New System Configuration and Reconductor 3L405

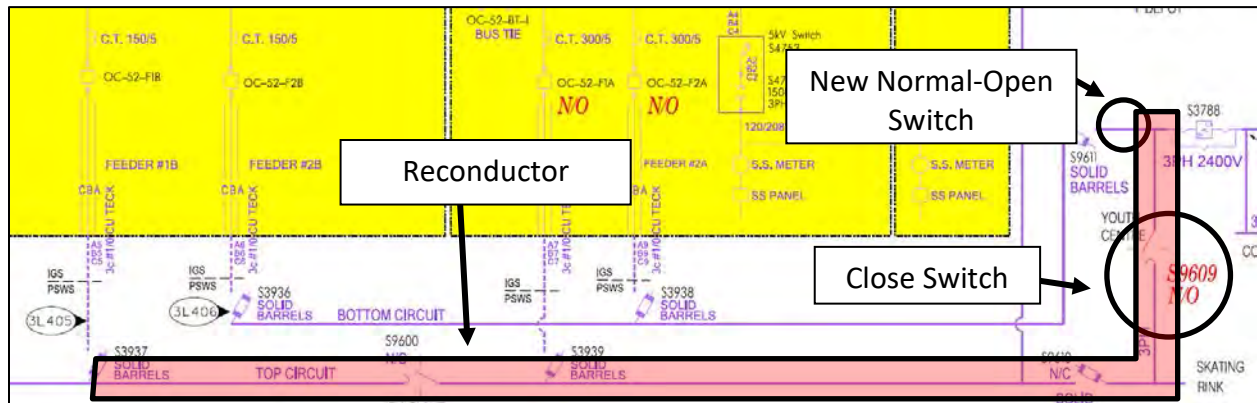
Project Scope: \$249,000

- ~940m of 1/0 ACSR (\$232,000)
- Overhead gang switch (\$17,000)

Table 7: Alternative 2.3 Voltages

	Existing (V pu)	Alternative 2.2 (V pu)	Alternative 2.3 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 0.968 B – 0.961 C – 0.962	A – 0.971 B – 0.958 C – 0.961
End of Line Load Growth Capacity	0 kW	35 kW	20 kW

Figure 6: Alternative 2.3 SLD



Alternative 2.4 - Reductor with Regulator Bank on 3L406

Project Scope: \$942,000

- 100A 2.4kV Regulator Bank (\$710,000)
- ~940m of 1/0 ACSR (\$232,000)

This alternative was not assessed as both Alternative 2.1 and Alternative 2.2 adequately address the low voltage issues on 3L406 individually. Combining both alternatives would be an unjustified increase in cost at this time; however, given that both alternatives are independent of each other, these alternatives could be combined in the future if a further increase in capacity is needed.

3. Capacity on 3L405 East

Alternative 3.1 - Reductor 3L405 East

Project Scope: \$232,000

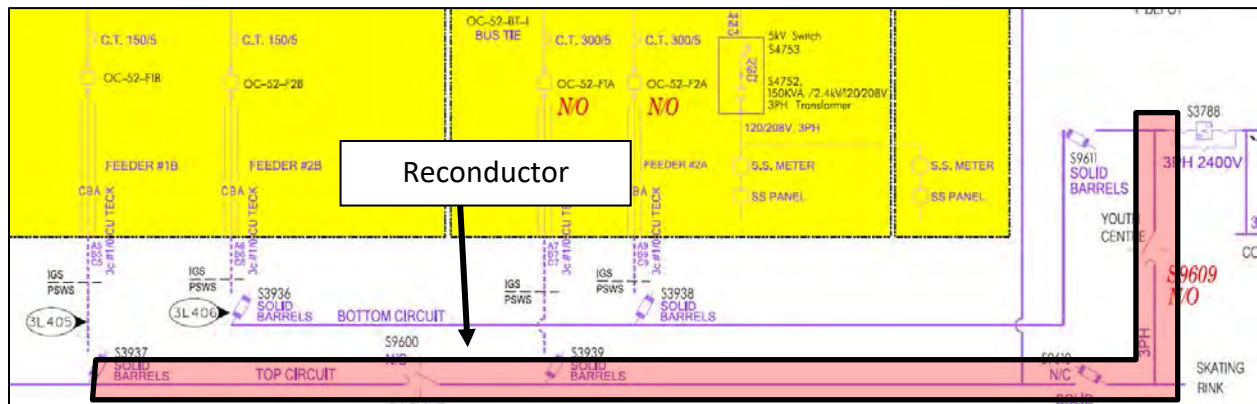
- ~940m of 1/0 ACSR, replacing a mixture of #4 and #6 ACSR

Although there are no existing low voltage issues on 3L405 East, capacity on the feeder is limited. A maximum load of 85 kW can be installed at the end of 3L405 East before voltage falls below 0.95 Vpu. This alternative allows for 230 kW of increased system capacity to account for continued load growth in Old Crow.

Table 8: Alternative 3.1 Voltages

	Existing (V pu)	Alternative 3.1 (V pu)
Worst Voltage on 3L405 East	A – 0.984 B – 0.986 C – 0.978	A – 0.988 B – 0.991 C – 0.986
End of Line Load Growth Capacity	85 kW	230 kW

Figure 7: Alternative 3.1 SLD



4. Alternatives for Low Voltage System Wide

Alternative 4.1 – Old Crow Voltage Conversion

Project Scope: >\$1,000,000

- Convert Old Crow system to 4160 V
 - o Change system to Wye
 - Rebuild over 6km of primary system to include a neutral conductor
 - System and generation wiring changes
 - o Replace distribution transformers that cannot be reconfigured to 4160 V
 - o Protection changes
 - Line-to-ground faults due to Wye system (Old Crow has poor grounding)

This alternative was not assessed further due to project cost and extended lead-times.

Recommendation

It is recommended that Alternatives 1.1, 2.2 and 3.1 are undertaken to both fix existing voltage issues and increase system capacity for future load growth.

Alternative 1.1 is the only alternative that addresses the low voltages on 3L405 North.

Alternatives 2.1, 2.2, and 2.3 all address low voltages on 3L406; however, Alternative 2.2 is the least-cost alternative. Alternative 3.1 allows for increased capacity on 3L405 East to accommodate load growth.

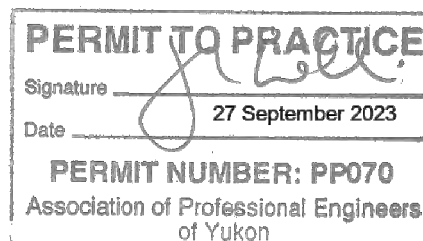
In total, the work that will be completed is:

- Regulator addition on 3L405 North;
- Reconductor 3L406, and
- Reconductor 3L405 East.



Old Crow Undervoltage (2023 Update)

Technical Study



Revision History

Revision	Date	Editor	Comments
R0	2023-09-26	Alex Deans	First version



Issue Summary

Old Crow has continued to see an increase in load growth year after year. New peak loads are straining the Old Crow system to a point where AEY cannot reliably provide electricity that is within voltage standards. This deficiency is caused by long distances between generation and customers, size of primary conductors, and the overall primary system voltage.

345KV North

345KV East

345KV West

Legend:

- 345KV North
- 345KV East
- 345KV West

Key:

Symbol	Description
1	345KV North
2	345KV East
3	345KV West
4	345KV North
5	345KV East
6	345KV West
7	345KV North
8	345KV East
9	345KV West
10	345KV North
11	345KV East
12	345KV West
13	345KV North
14	345KV East
15	345KV West
16	345KV North
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88	345KV North
89	345KV East
90	345KV West
91	345KV North
92	345KV East
93	345KV West
94	345KV North
95	345KV East
96	345KV West
97	345KV North
98	345KV East
99	345KV West
100	345KV North

Figure 1 - Old Crow SLD

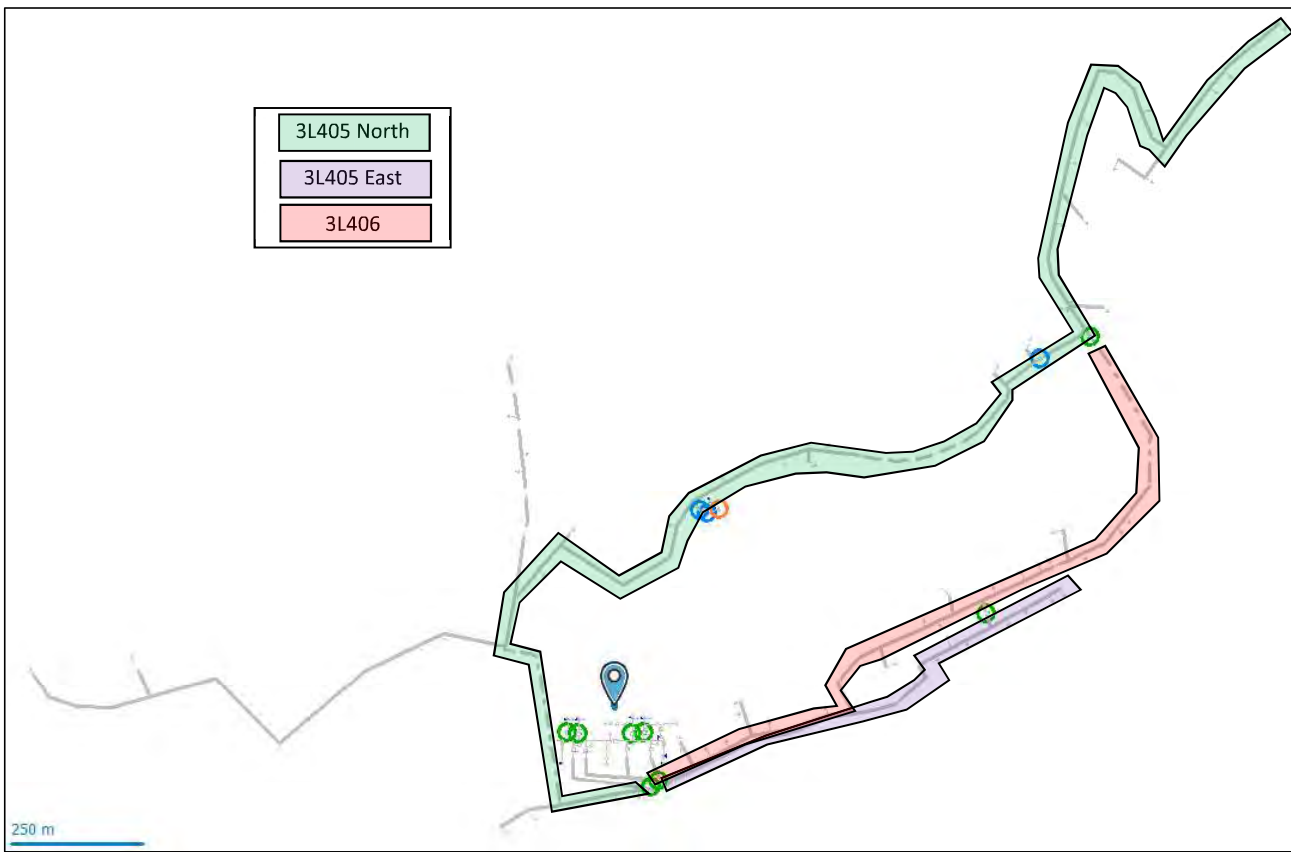


Figure 2 - Old Crow CYME Map



Seasonal Loading

Summer

Two scenarios were analyzed in CYME during summer loading using historical data between July 1, 2023, and July 6, 2023; Scenario 1 represents Battery Energy Storage System (BESS)-only generation and Scenario 2 represents Photo Voltaic (PV) array generation with BESS charging. These dates were chosen so that the Old Crow system would be diesel-off (i.e., the Old Crow system is solely powered by the PV array and battery).

Scenario 1: BESS-only generation

Historical data shows a peak in BESS generation on July 3, 2023, at 10:20pm equaling 241 kW. Since the BESS is connected at the plant, and the modelling goal is confirming voltage levels and not fault current, this scenario was modeled in CYME with all generators connected with voltage set at 1.01Vpu (BESS set point), and the model loaded at 33% (to match measured BESS output).

Table 1 – Scenario 1 PV and BESS Historical Data

Date	Total System Load (kW)	CYME Load %	PV Output (kW)	BESS Output (kW)	Diesel Output (kW)
03-Jul-23 (10:20pm)	241	33	0	241	0

Note - The BESS has the capability to generate up to 685 kW of power which is why all generators were left active in the model.

Table 2 – Scenario 1 Old Crow Voltages

Study Area	Summer Loading – Scenario 1 (Worst Vpu)
3L406	A – 0.977 B – 0.970 C – 0.976
3L405 North	A – 0.974 B – 0.976 C – 0.977
3L405 East	A – 0.995 B – 0.996 C – 0.993

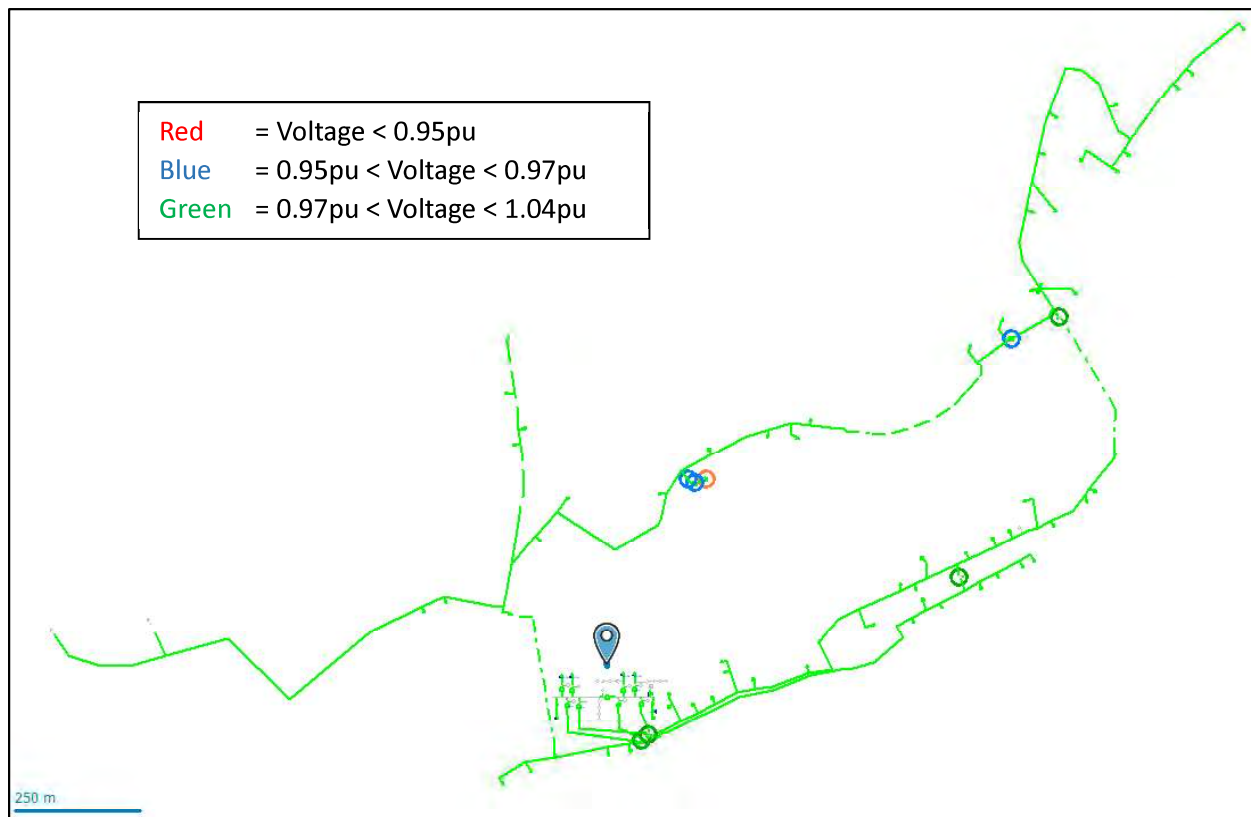


Figure 3 - Old Crow Scenario 1 CYME Map

Scenario 2: PV generation with BESS charging

The peak load on the system – less BESS charging – was found on July 3, 2023, and equaled 322 kW. To model this scenario a generator was placed at the PV array site, all diesel generators at the main plant were disconnected, the BESS was set to charge at 95 kW, and the model was loaded at 44%. The voltage setpoint for the PV site was set to 1.05Vpu, resulting in a 1.01Vpu measurement at the plant bus (BESS setpoint voltage).

Table 3 - Scenario 2 PV and BESS Historical Data

Date	Total System Load (kW)	CYME Load %	PV Output (kW)	BESS Output (kW)	Diesel Output (kW)
03-Jul-23 (2:25pm)	322	44	417	-95	0

Assumptions:

The historical data shows the line-to-line voltage on the generator bus for AB, BC, and CA which equal 2.40 kV, 2.38 kV, and 2.41kV respectively. To achieve a similar bus voltage in CYME, the generator at the PV site needs to be set to 2.5kV. We can then assume that all voltages downstream of the diesel plant on 3L406 and 3L405 East will represent real-world voltages.



Table 4 - Scenario 2 Old Crow Voltages

Study Area	Summer Loading – Scenario 2 (Worst Vpu)
3L406	A – 0.968 B – 0.957 C – 0.961
3L405 North	A – 0.984 B – 0.985 C – 0.986
3L405 East	A – 1.002 B – 1.001 C – 0.995

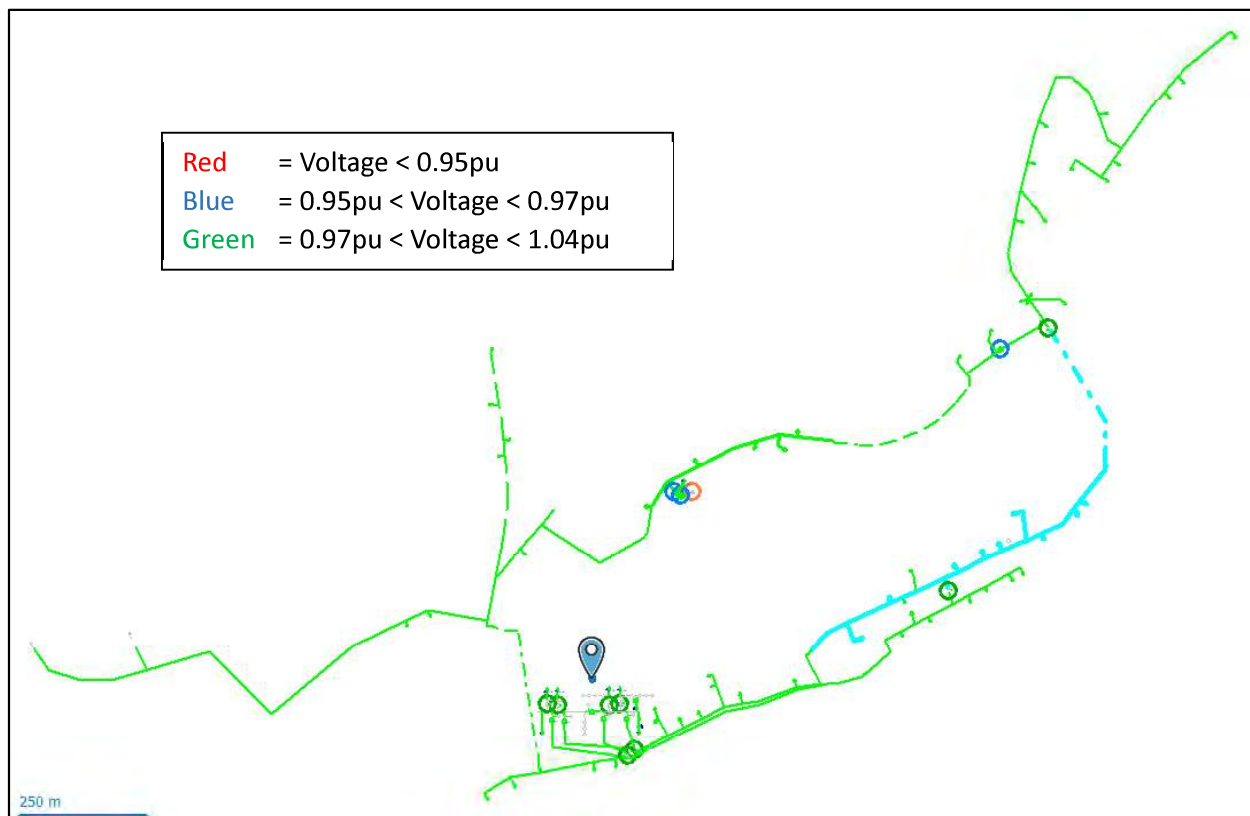


Figure 4 - Old Crow Scenario 2 CYME Map



Winter

The CYME model is run at 100% and includes the assumed loads of the new 10-plex and health center that was built on 3L405 North (see attached pdf).



DPS Old Crow
Health Center and 1

Table 5 – Old Crow Winter Loading Voltages

Study Area	Winter Loading – No PV (Worst Vpu)
3L406	A – 0.928 B – 0.904 C – 0.923
3L405 North	A – 0.918 B – 0.923 C – 0.927
3L405 East	A – 0.984 B – 0.986 C – 0.978

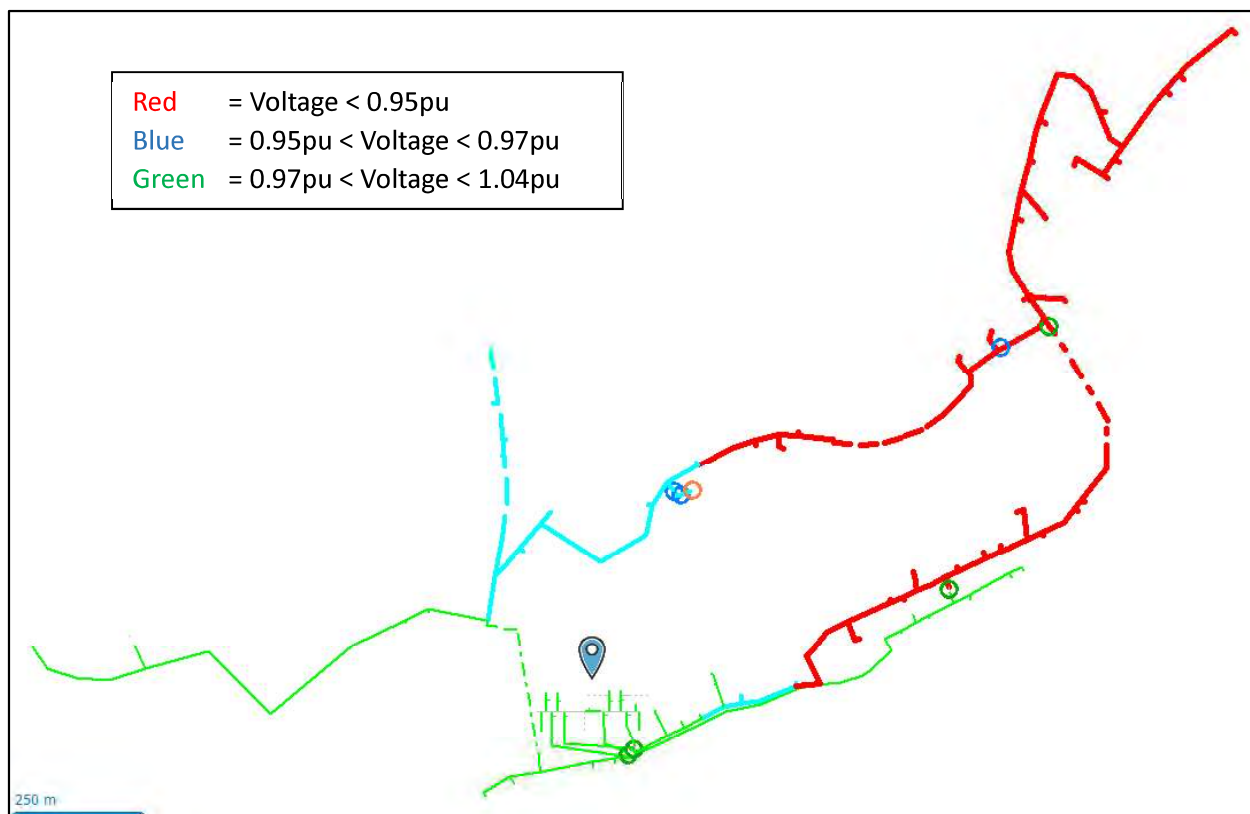


Figure 5 – Winter Loading CYME Map

Alternatives

There are two problems within the Old Crow system that are addressed in the alternatives below; they are the following:

- Low voltage on 3L405 North during Winter loading,
- Low voltage on 3L406 during Winter loading,

For modelling each alternative, the modification specified in each option was added, with no changes to system loading. The new worst EOL voltage was recorded.

To determine an approximate load growth capacity, load was added until the worst end-of-line voltage hit 0.95 Vpu.

Alternatives for Low Voltage on 3L405 North

Alternative 1 - Regulator Bank on 3L405 North

Project Scope: \$710,000

- 100A 2.4kV Regulator Bank

Regulator location was determined using two criteria:

1. Locating a point near where voltages on 3L405 North begin to fall below AEY standard during peak Winter loading,
2. And allows for the largest increase in end-of-line load growth.

Table 6 - Alternative 1 Voltages

	Existing (V pu)	Alternative 1 (V pu)
Worst Voltage on 3L405 North	A – 0.918 B – 0.923 C – 0.927	A – 0.994 B – 0.994 C – 1.000
End of Line Load Growth Capacity	0kW	80kW

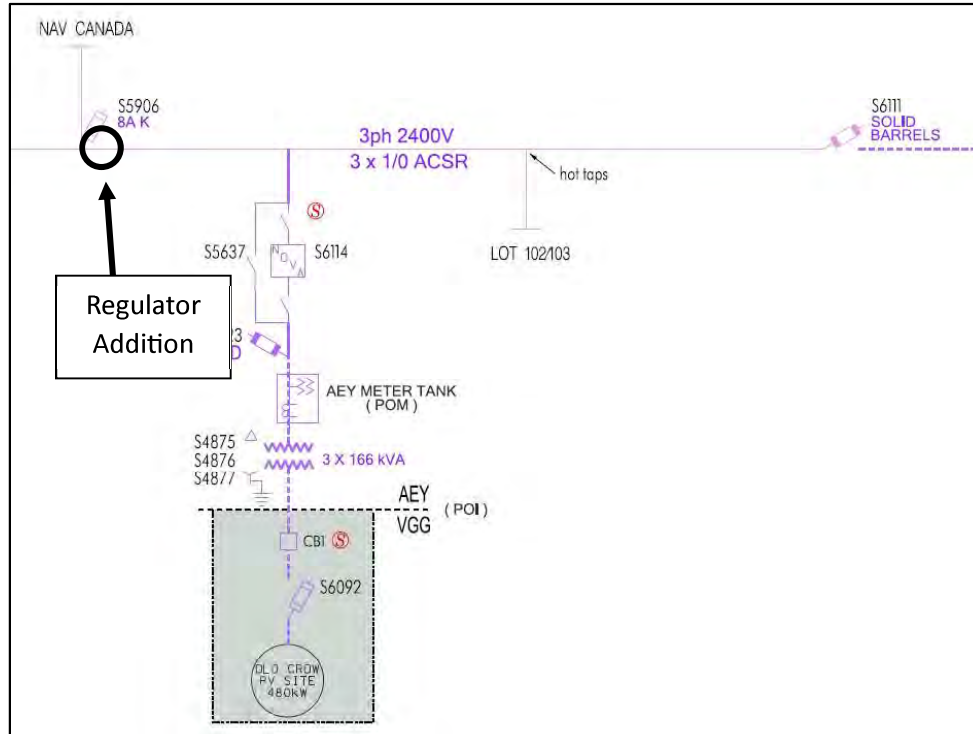


Figure 6 - Alternative 1 SLD

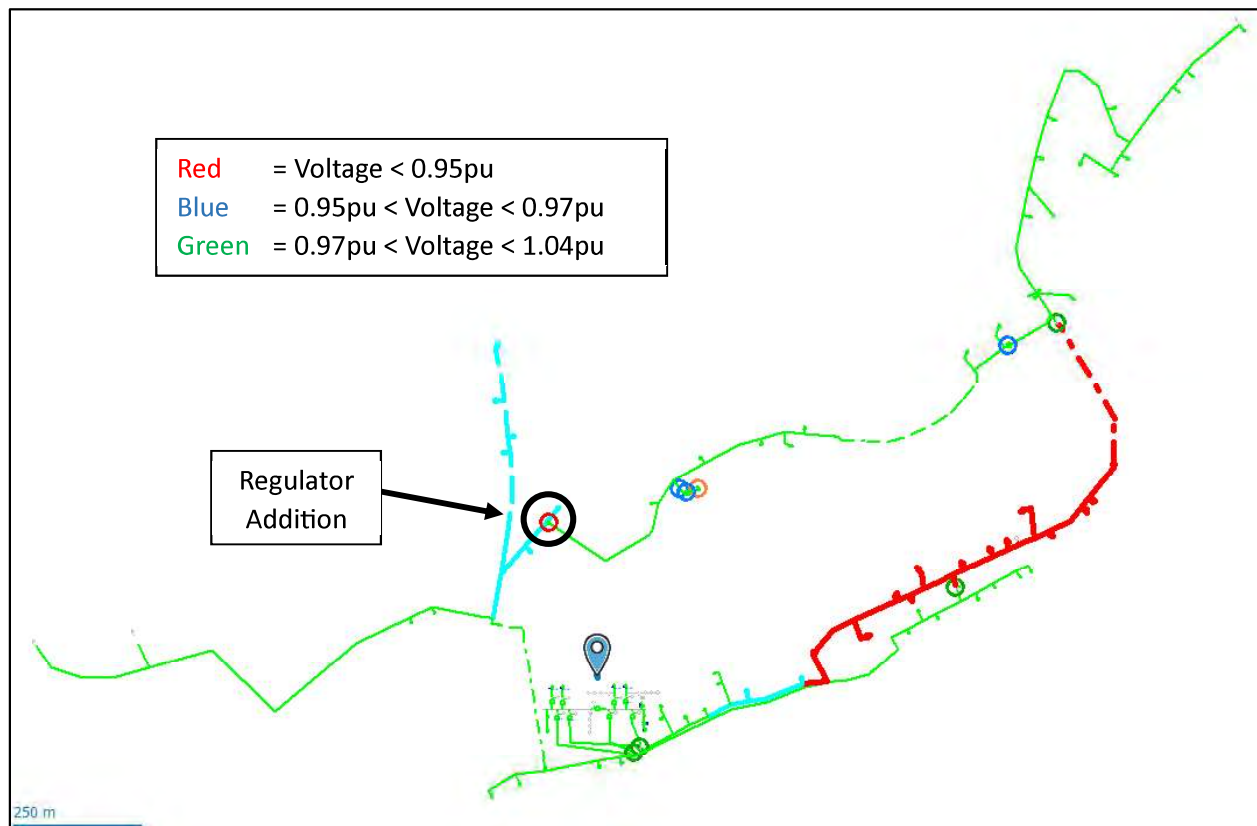


Figure 7 - Alternative 1 CYME Map

Project Scope: \$787,000

- 100A 2.4kV Regulator Bank (\$710,000)
- ~310m of 4/0 UG AL (\$77,000)

Regulator location is the same as in Alternative 1. The existing 1C1 AL underground cable between S8324 and S8325 is a bottle neck for voltage drop. By upgrading the cable size to 4/0 AL, capacity on 3L405 can be further increased.

Table 7 - Alternative 2 Voltages

	Existing (V pu)	Alternative 1 (V pu)	Alternative 2 (V pu)
Worst Voltage on 3L405 North	A – 0.918 B – 0.923 C – 0.927	A – 0.994 B – 0.994 C – 1.000	A – 0.992 B – 0.996 C – 1.000
End of Line Load Growth Capacity	0kW	80kW	100kW

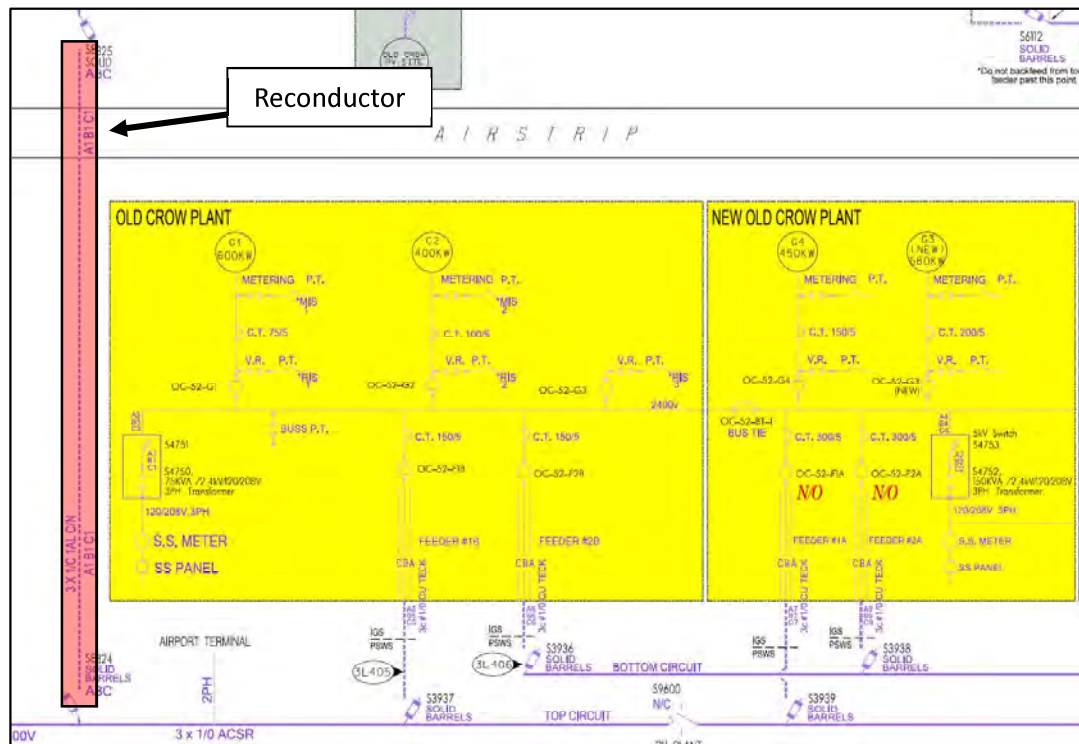


Figure 8 - Alternative 2 SLD

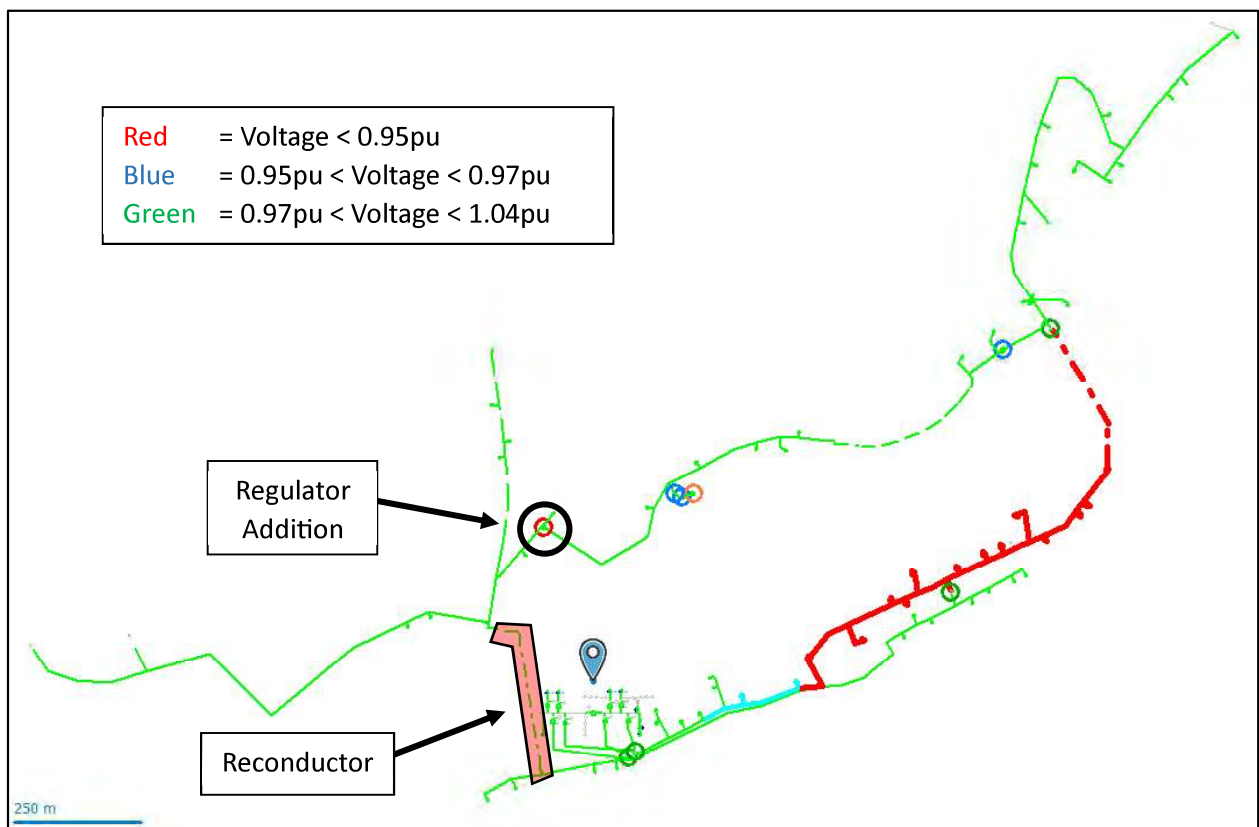


Figure 9 - Alternative 2 CYME Map



Alternatives for Low Voltage on 3L406

Alternative 3 - Regulator Bank on 3L406

Project Scope: \$710,000

- 100A 2.4kV Regulator Bank

Regulator location was determined in the same manner as in Alternative 1.

Table 8 - Alternative 3 Voltages

	Existing (V pu)	Alternative 3 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 1.004 B – 0.987 C – 1.002
End of Line Load Growth Capacity	0kW	75kW

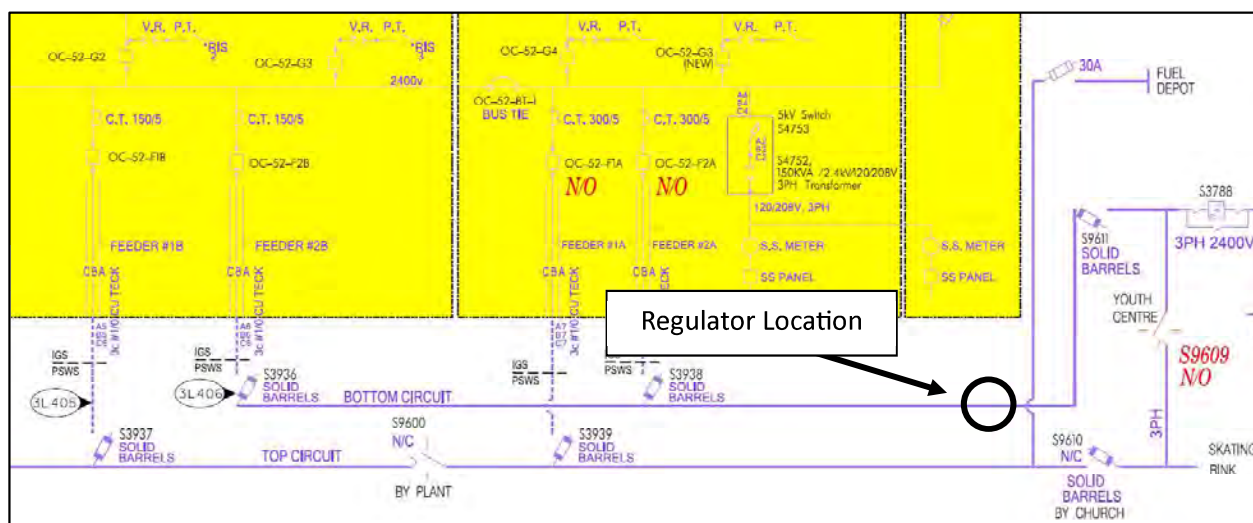


Figure 10 - Alternative 3 SLD

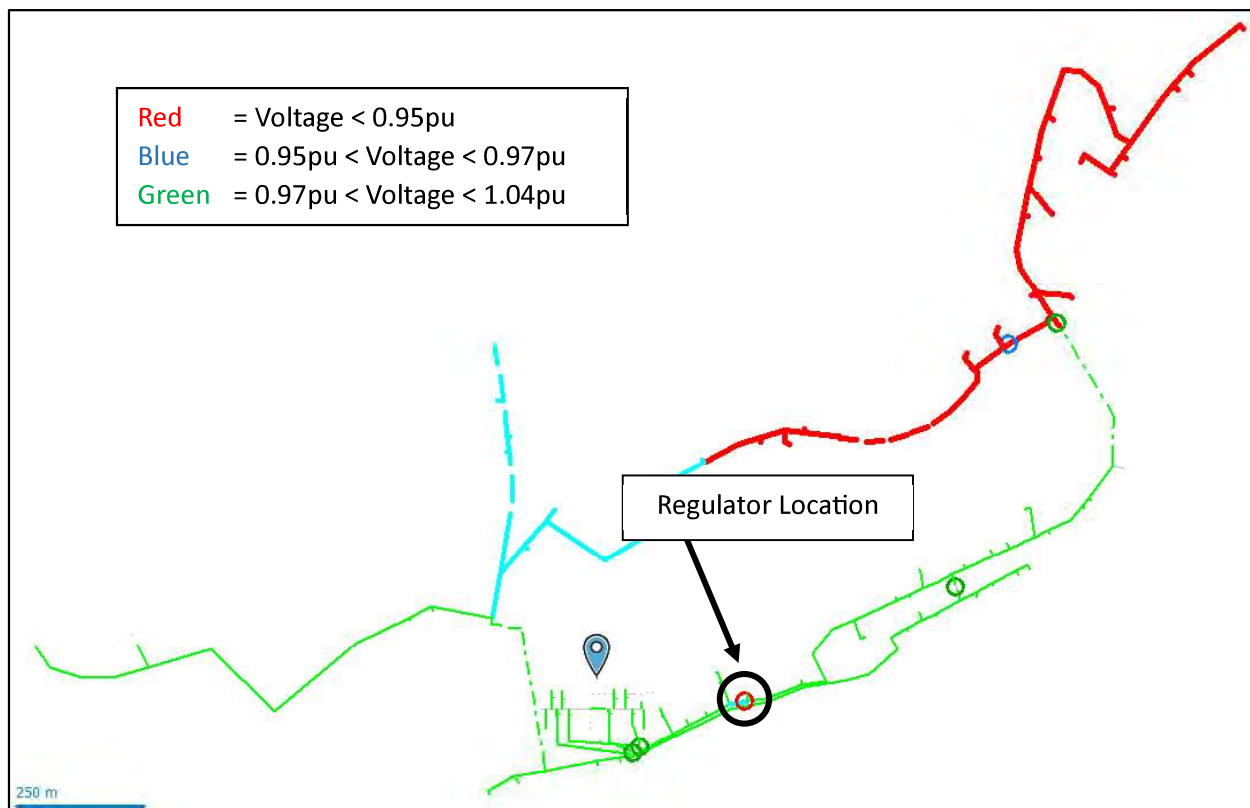


Figure 11 - Alternative 3 CYME Map

Alternative 4 - Reconductor 3L406

Project Scope: \$232,000

- ~940m of 1/0 ACSR, replacing a mixture of #4 and #6 ACSR

Table 9 - Alternative 4 Voltages

	Existing (V pu)	Alternative 4 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 0.968 B – 0.961 C – 0.962
End of Line Load Growth Capacity	0kW	35kW

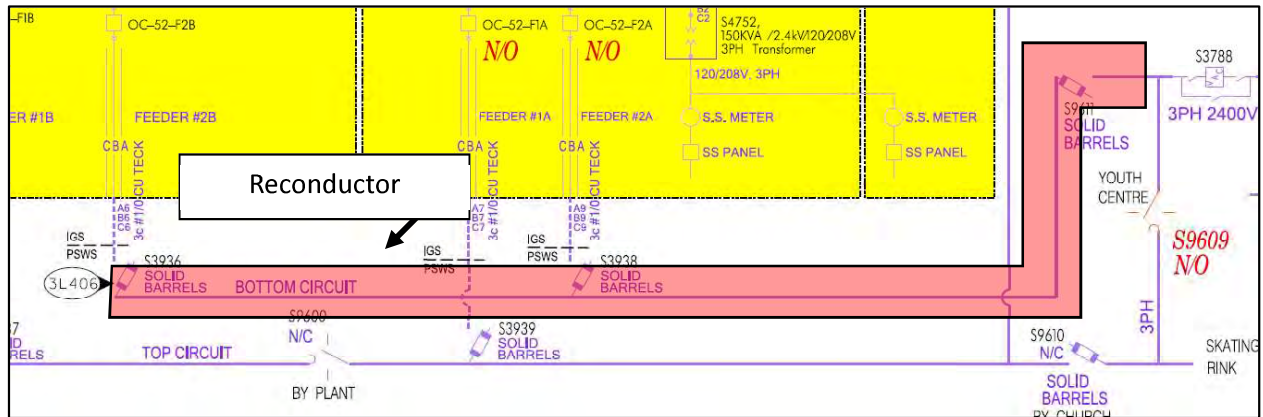


Figure 12 - Alternative 4 SLD

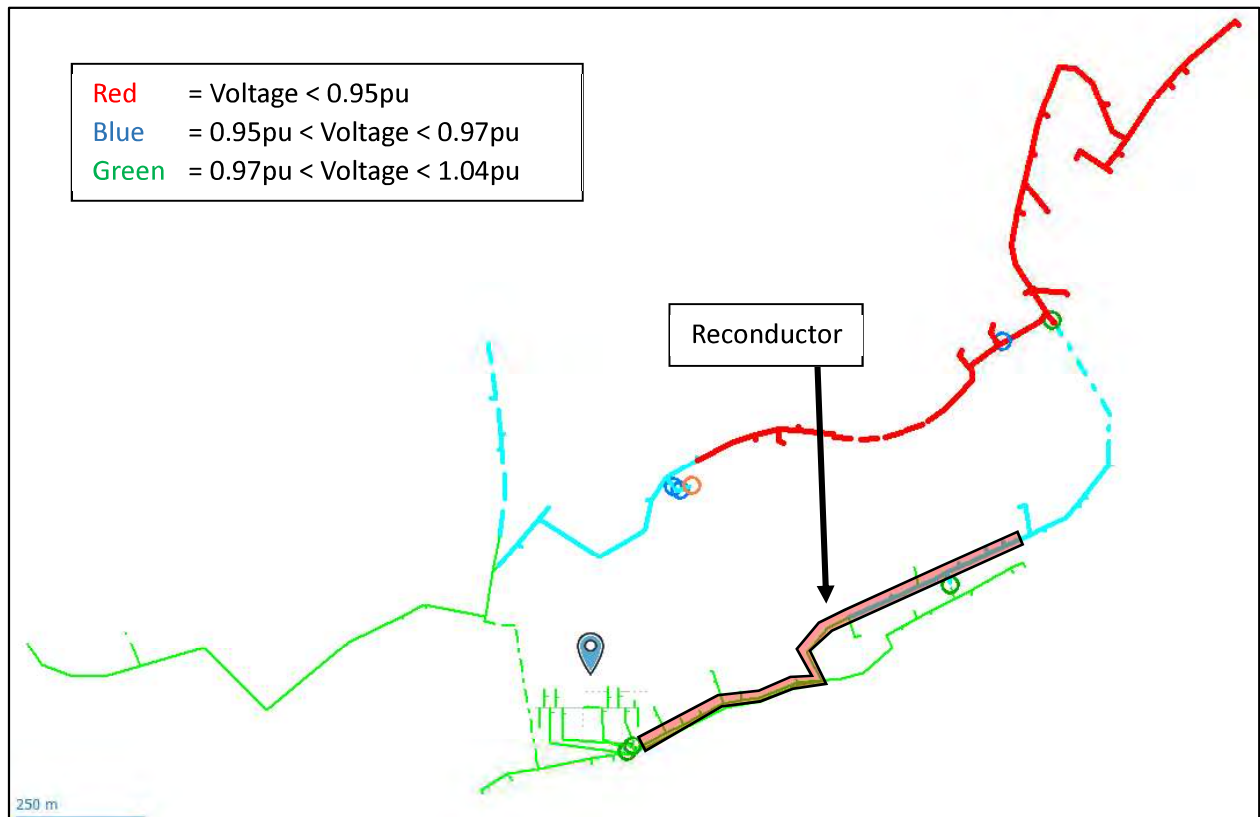


Figure 13 - Alternative 4 CYME Map

Project Scope: \$249,000

- Table 10 - Alternative 5 Voltages

	Existing (V pu)	Alternative 4 (V pu)	Alternative 5 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 0.968 B – 0.961 C – 0.962	A – 0.971 B – 0.958 C – 0.961
End of Line Load Growth Capacity	0kW	35kW	20kW

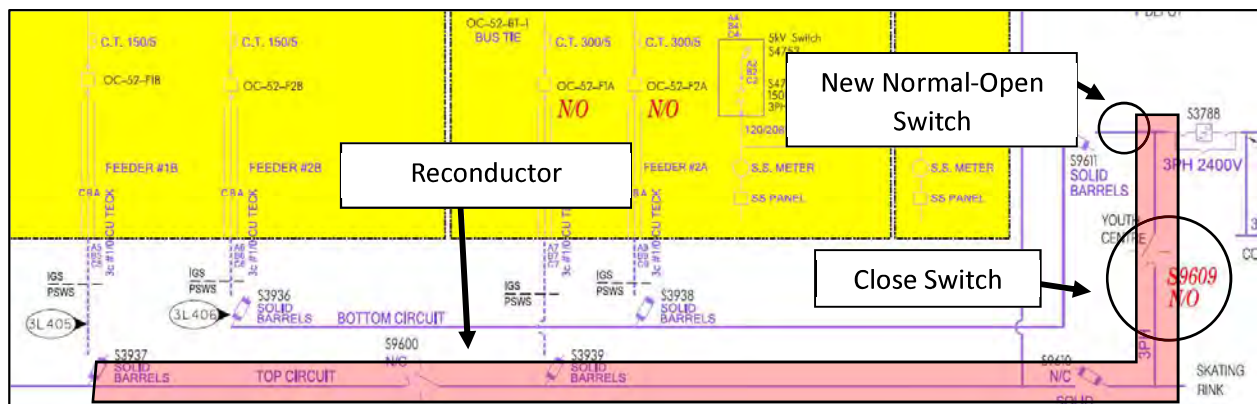


Figure 14 - Alternative 5 SLD

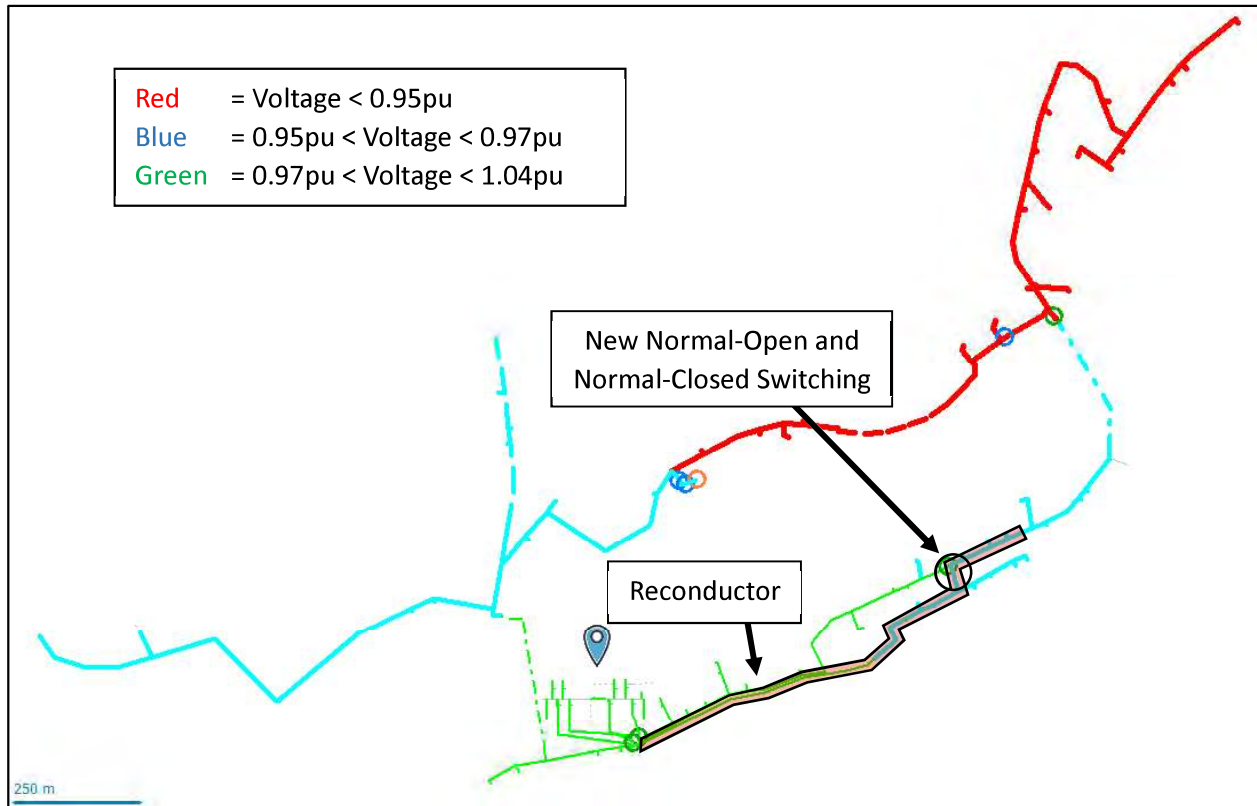


Figure 15 - Alternative 5 CYME Map

Alternative 6 - Reconductor with Regulator Bank on 3L406

Project Scope: \$942,000

- 100A 2.4kV Regulator Bank (\$710,000)
- ~940m of 1/0 ACSR (\$232,000)

This alternative was not assessed as both Alternative 3 and Alternative 4 adequately address the low voltage issues on 3L406 individually. Combining both alternatives would be an unjustified increase in cost at this time; however, given that both alternatives are independent of each other, these alternatives could be combined in the future if a further increase in capacity is needed.



Alternatives for Low Voltage System Wide

Alternative 7 – Old Crow Voltage Conversion

Project Scope: >\$1,000,000

- Convert Old Crow system to 4160 V
 - Change system to Wye
 - Rebuild over 6km of primary system to include a neutral conductor
 - System and generation wiring changes
 - Replace all distribution transformers with 4160 V transformers
 - ~65 transformers
 - Protection changes
 - Line-to-ground faults due to Wye system (Old Crow has poor grounding)

This alternative was not assessed due to project cost and extended lead-times.

Recommend Alternative

The recommended solutions for 3L405 North and 3L406 are Alternative 1 and Alternative 4 respectively.

Alternative 1 is the only alternative that addresses the low voltages on 3L405 North. Alternatives 3, 4, and 5 all address low voltages on 3L406; however, Alternative 4 is the least-cost alternative.

September 28, 2023

AEY-YUB-061

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-061

Reference: 2023-24 GRA, Business Case #30 – 6L19 Voltage Improvement, PDF pages 98-118

Issue: Capital expenditures (Distribution Improvements)

Request:

Please provide the comparative cost-benefit analysis prepared for each of the seven alternatives examined.

Response:

Please refer to the comparative cost-benefit analysis prepared in the table below.

**Table 1: Comparative Cost-Benefit Analysis
(\$Millions)**

Alternatives	Estimate
1. Install Two New Regulators on 6L11 and 6L19	\$1.19
2. Reconductor 6L11 and 6L19 <i>Does not fix New Constab. voltage issues</i>	\$50+
3. Reconductor 6L11 and Install a New Regulator on 6L19 <i>Does not fix New Constab. And Teslin voltage issues</i>	\$7.2
4. Boost S150 Voltage, Reconductor 6L11, Install Regulator on 6L19 <i>Does not fix New Constab. voltage issues</i>	\$7.2
5. Boost S150 Voltage, Relocate Two Reg Banks, and Install Regulator on 6L11	\$0.95 <i>Recommended Alternative</i>
6. Scenario 4 THELP: Install Regulator on 6L11, Install Regulator on 6L19 <i>Does not fix New Constab. And Teslin voltage issues</i>	\$1.19

September 28, 2023

AEY-YUB-061

Figure 1: Comparison of Alternative Performance

Location	Existing		
	Va	Vb	Vc
McRae Sub (35kV)	0.945	0.946	0.944
5L649 EOL	1.019	1.019	1.018
5L631 EOL	-	-	0.949
South McLintock Sub (35kV)	0.932	0.946	0.934
5L611 EOL	-	-	0.926
Marsh Lake Sub (35kV)	0.909	0.927	0.917
5L612 EOL	0.958	-	-
New Constabulary Sub (35kV)	0.902	0.919	0.912
5L615 EOL	0.855	-	-
Johnson Crossing Sub (35kV)	0.851	0.843	0.861
Teslin Lake Sub (35kV)	0.819	0.796	0.828
4L301 EOL	-	0.802	-
Teslin Sub (35kV)	0.812	0.787	0.821
5L613 EOL	0.879	-	-
5L614 EOL	-	0.868	-
Worst Voltage on 6L19	0.815	0.791	0.824

Alternative 1			Alternative 2			Alternative 3			Alternative 4			Alternative 5			Alternative 6		
Va	Vb	Vc	Va	Vb	Vc	Va	Vb	Vc	Va	Vb	Vc	Va	Vb	Vc	Va	Vb	Vc
1.025	1.027	1.025	0.984	0.985	0.984	0.977	0.978	0.977	1.018	1.019	1.019	0.987	0.989	0.987	1.023	1.025	1.028
1.033	1.027	1.032	1.033	1.032	1.032	1.031	1.030	1.029	1.032	1.031	1.031	1.030	1.029	1.029	1.033	1.030	1.033
-	-	0.964	-	-	0.964	-	-	0.959	-	-	0.961	-	-	0.958	-	-	0.963
1.017	1.013	1.020	1.016	1.016	1.015	0.999	1.011	1.024	1.018	1.016	1.015	1.038	1.039	1.035	1.017	1.014	1.015
-	-	1.003	-	-	1.001	-	-	0.993	-	-	1.002	-	-	1.024	-	-	1.001
0.998	0.996	1.007	0.994	1.000	1.001	0.979	0.994	0.988	0.998	0.999	1.001	1.018	1.022	1.021	0.997	0.997	1.000
0.995	-	-	0.993	-	-	0.992	-	-	0.992	-	-	0.994	-	-	0.990	-	-
0.995	0.990	1.003	0.989	0.993	0.997	0.973	0.987	0.983	0.992	0.992	0.997	1.012	1.015	1.017	0.991	0.990	0.996
0.952	-	-	0.949	-	-	0.931	-	-	0.948	-	-	0.968	-	-	0.946	-	-
1.019	1.006	1.018	0.979	0.972	0.986	1.020	1.007	1.019	1.017	1.007	1.016	1.020	1.013	1.019	1.005	0.982	1.004
0.994	0.969	0.993	0.970	0.957	0.978	0.994	0.968	0.993	0.991	0.968	0.990	0.994	0.974	0.993	0.979	0.942	0.977
-	0.972	-	-	0.958	-	-	0.972	-	-	0.969	-	-	0.975	-	-	0.951	-
0.988	0.962	0.987	0.968	0.954	0.975	0.988	0.961	0.987	0.985	0.960	0.984	0.988	0.967	0.987	0.973	0.935	0.971
1.027	-	-	1.027	-	-	1.033	-	-	1.030	-	-	1.033	-	-	1.028	-	-
-	1.021	-	-	1.025	-	-	1.026	-	-	1.024	-	-	1.030	-	-	1.016	-
0.958	0.973	0.960	0.968	0.954	0.975	0.927	0.939	0.929	0.988	0.963	0.986	0.991	0.970	0.989	0.975	0.944	0.973

September 28, 2023

AEY-YUB-062

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-062

Reference: 2023-24 GRA, Business Case #31 – Whistle Bend Subdivision, PDF pages 119-122, paragraph 2; 2023-24 GRA Schedules, S9.2

Issue: Capital expenditures (Street and Sentinel Lighting)

Quote: This is new construction and is fully contributed other than the Board approved \$1,240 per street light.

...

Project Schedule and Cost

**Table 1: Project Costs and Schedules
(\$000)**

Description	Completion	Distribution Cost	Streetlight Cost
Stage 3D + 3E	2019	567	214
Stage 4	2019	1,910	551
Stage 4D	2020	N/A	159
Stage 5	2020	944	344
Stage 6	2023	718	50
Stage 7A	2023	352	86
Stage 8	2022	140	103
Stage 7B	2023	460	301
Stage 9A	2024	683	186
Stage 9B	2025	458	147

Preamble: The Board requires further detail respecting the “Distribution Cost” and the contribution amounts.

Request:

- (a) Referring to Business Case #31, Table 1 (PDF page 121), please reference where the 2019 Street light Cost of \$0.214 million for Stage 3D and 3E can be found on 2023-24 GRA Schedules, S9.2. If the response to part (a) indicates Line No. 310 under the years 2019 and 2020 (\$0.166 million and \$0.048 million respectively), please identify the business case associated with all other amounts on Line No. 314.

September 28, 2023

AEY-YUB-062

- (i) If the response to part (a) refers to some other line no. on S9.2, please explain any variance between the amount shown on the line no. identified in part (a) and the amount of \$0.214 million.
 - (ii) Referring to Table 1 as quoted above, please explain where the amounts shown under the column "Distribution Cost" can be found on AEY's 2023-24 GRA Schedules, S9.2.
- (b) Referring to Table 1 as quoted above, please explain where the amounts shown under the column "Distribution Cost" can be found on AEY's 2023-24 GRA Schedules, S9.2.
- (c) Please revise Table 1 to include columns indicating the quantum of units and the total contributed amounts for each of the lines that indicate each of the 10 stages.
- (d) Please provide a citation to the "Board approved \$1,240 per streetlight" referenced by AEY in the quote above.

Response:

- (a) The streetlights for stage 3D and 3E were inadvertently included in line 146 Whistle Bend Stage 3 in the presentation of Schedule 9.2. AEY will break these costs out in the updated Schedule to be filed in the Compliance Filing to the Application.
 - (i) \$0.214 million is what was included in line 146.
 - (ii) Please refer to the table Distribution Cost Line Reference in the response to part (b) below.
- (b) The amounts shown under the column "Distribution Cost" are found on lines 146 through 153 of Schedule 9.2. Table 1 as quoted above shows the amounts on a per stage basis whereas Schedule 9.2 shows the amounts on an as expended basis. Please refer to the table below for a breakdown:

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Table 1: Distribution cost Line reference

Description	Completion	Distribution Cost (\$000)	Schedule 9.2 Line Reference
Stage 3D + 3E	2019	567	146
Stage 4	2019	1910	147
Stage 4D	2020	n/a	n/a
Stage 5	2020	944	148
Stage 6	2023	718	149
Stage 7A	2023	352	150
Stage 8	2022	140	151
Stage 7B	2023	460	150
Stage 9A	2024	683	152
Stage 9B	2025	458	152

(c) Project Schedule and Cost

Table 2: Project Costs and Schedules

Description	Completion	Distribution Cost (\$000)	Streetlight Cost (\$000)	Contributed Amount Aug. 2023 (\$000)	Number of Streetlights
Stage 3D + 3E	2019	567	214	847	46
Stage 4	2019	1910	551	2393	106
Stage 4D	2020	n/a	159	148	15
Stage 5	2020	944	344	1169	89
Stage 6	2023	718	50	996	67
Stage 7A	2023	352	86	201	42
Stage 8	2022	140	103	219	9
Stage 7B	2023	460	301	185	30
Stage 9A	2024	683	186	186	29
Stage 9B	2025	458	147	0	22

(d) Yukon Energy Corporation & The Yukon Electrical Company Ltd. Terms and Conditions of Service, Schedule B Maximum Company Investment 1 C) Municipal Street Lighting: \$1,240.00 per light. These T&Cs were approved by the YUB in Board Decision 2011-05

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-063

Reference: 2023-24 GRA, Business Case #34 – Yukon Government Robert Campbell Highway Streetlights, PDF pages 131-134; 2023-24 GRA Schedules, S9.2

Issue: Capital expenditures (Street and Sentinel Lighting)

Request:

Referring to the Business Case #34, Table 1 (PDF page 132), please reference where the street light project costs of \$0.907 million (\$0.350 million – Material; \$0.557 million - Labour) can be found on 2023-24 GRA Schedules, S9.2.

Response:

These capital expenditures are included on Schedule 9.2, line 311. Please refer to AEY-YUB-046(a) Attachment 1.

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AEY-YUB-064

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)****Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023****AEY-YUB-064****Reference:** 2023-24 GRA, Section 9.5, Streetlights, PDF pages 177; Schedule 9.2**Issue:** Street lights**Preamble:** The Board requires further information concerning street lights.**Request:**

- (a) Please provide the capital spend to date (2023) on the new customer, McIntyre, and Whistle Bend Streetlight installation projects.
- (b) For New Customer Streetlight Installations (Schedule 9.2 line 311), please explain the material increase in forecast expenditures for 2023 over 2022.
- (c) Are there offsetting customer contributions for any of the street light installations? If so, please provide the amount of customer contributions.

Response:

- (a) Summary of Streetlight Costs Year-To-Date August 2023.

**Table 1: Streetlight Costs
(\$)**

	Capital	Contribution	Net Cost of Capital
New Customer Streetlights	513,386	(933,511)	(420,125)
Whistle Bend Street Lights - Stage 6	596	-	596
Whistle Bend Street Lights - Stage 7	153,532	-	153,532
Whistle Bend Street Lights - Stage 8	1,210	(43,795)	(42,584)
McIntyre Subdivision Streetlight Rebuild	5,152	5,153	10,305
Total	673,876	(972,152)	(298,276)

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- (b) The increased cost from 2022 to 2023 on line 311 of Schedule 9.2 is due mainly to the streetlighting and underground supply cables to be installed from km 1 to km 4 on the Robert Campbell Highway near Watson Lake. This is a customer driven project request by the Yukon Government.
- (c) Please refer to the response to part (a) above for 2023. New Customer Streetlights installation contributions in 2022 total \$462,488.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-067

Reference: 2023-24 GRA, Sections 9.7 and 9.9, General Property Plant and Equipment, PDF pages 178 and 179-180; Schedule 9.2.; Business Case #22, PDF pages 2-6

Issue: ATCO CIS Replacement

Preamble: The Board requires further information.

Request:

- (a) What is the expected life of the replacement system?
- (b) Is the replacement system a licensed product?
- (c) If the replacement system is a licensed product, what do the capital costs represent?
- (d) Will AEY have ownership for those capital costs attributed to it? Please explain.
- (e) Please explain how increasing demands of electrification and renewable technologies affect the complexity of the billing system.
- (f) Please provide the economic analysis that demonstrates that this ATCO CIS Replacement is the lowest cost option.
- (g) AEY's parent company is transitioning away from the use of CIS; how were charges to AEY (both capital and operating) determined?

Response:

- (a) Oracle's Customer Cloud Service (CCS) product is a cloud-based application which receives monthly security based patches, and tri-annual software based improvements/enhancements that are mandatory to be deployed through the Oracle subscription. The exact life expectancy is unknown at this point in time, but

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it would be similar to that of ATCO Oracle ERP system, which follows a similar process of keeping the cloud-based software up-to-date and current.

- (b) Yes, the replacement product is a subscription-based Oracle product called Oracle Customer Cloud Service (CCS).
- (c) The licensed Oracle CCS product includes out-of-box functionality, requiring some configuration in order to meet ATCO's technical and business requirements. The capital costs represent the costs associated with labour, computing (which includes software subscription costs, software licensing costs, IT environment costs, and IT storage costs), costs associated with designing, building, testing, and implementing a reliable and robust billing system while meeting ATCO's specific business and technical requirements and ensuring the transition from ATCO's legacy CIS to Oracle CCS is as seamless as possible for AEY's customers.
- (d) Yes, AEY will be attributed 62 percent of total project cost. The percentage allocation has been determined based on number of customers being served by AEY.
- (e) The replacement of ATCO's end of life CIS will provide customers with a modern CIS that is flexible to new and growing customer requirements as a modern CIS will facilitate advancements in electrification and renewable technologies. The implementation of Oracle CCS for AEY followed the principle of replacing existing functionality that existed in ATCO's legacy CIS. That said, the Oracle CCS Software as a Services (SaaS) product lends itself well to out-of-the-box configurations to meet future demands of customer and industry needs. This includes, but is not limited to, customer growth and allows for management of large volumes of meter data. It also integrates with AMI to enable the management of enhanced automated services including on-demand time-of-use meter readings and remote connect and disconnects.

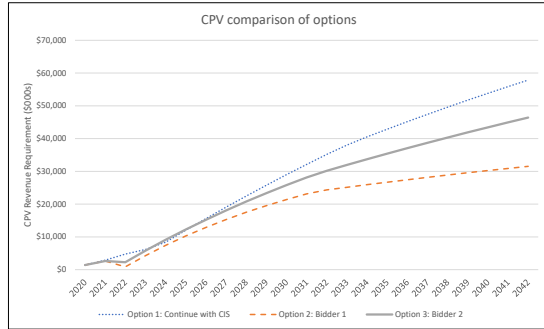
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- (f) Please refer to AEY-YUB-067(f) Attachment 1 for the annual revenue requirement and cumulative revenue requirement for each of the explored scenarios over 20-years. Oracle CCS was chosen as the lowest cost option.
- (g) AEY is utilizing a separate and distinct instance of Oracle CCS from that of ATCO Electric and ATCO Gas Distribution Utilities (different utility requirements). Therefore, all capital and operating costs allocated to AEY are those for the separate North of 60 implementation.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

No.	CIS Project Cumulative Present Value Analysis																												
1	CIS Update Project		[0]	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	
2	Discount Rate	7.93%	yr	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
3																													
4	x 1) Undiscounted Revenue Requirement (\$000s) - link to option																												
Option 1: Continue with CIS			1,407	1,624	2,132	1,776	3,050	5,321	5,611	5,938	6,247	6,566	6,907	7,246	7,644	7,654	7,330	7,361	7,746	8,204	8,660	9,125	9,612	10,123	10,740	3,369	3,002	2,640	
Option 2: Bidder 1			1,407	1,342	(2,087)	4,303	4,243	4,186	4,144	4,114	4,067	4,024	3,996	3,962	3,065	2,183	2,284	2,407	2,515	2,660	2,816	2,944	3,079	3,247	3,451	101	91	80	
7	Option 3: Bidder 2		1,407	1,342	(441)	4,425	4,505	4,593	4,703	4,858	4,974	5,101	5,251	5,401	5,116	4,813	5,067	5,392	5,671	5,967	6,365	6,699	7,054	7,508	7,923	439	393	348	
8																													
9	x 2) Cumulative Present Value Revenue Requirement (\$000s)																												
Option 1: Continue with CIS			\$1,407	\$2,912	\$4,743	\$6,155	\$8,402	\$12,036	\$15,585	\$19,065	\$22,458	\$25,762	\$28,982	\$32,112	\$35,171	\$38,009	\$40,527	\$42,870	\$45,155	\$47,397	\$49,589	\$51,730	\$53,819	\$55,857	\$57,861	\$58,443	\$58,924	\$59,316	
Option 2: Bidder 1			\$1,407	\$2,651	\$859	\$4,282	\$7,408	\$10,266	\$12,887	\$15,298	\$17,507	\$19,532	\$21,395	\$23,106	\$24,333	\$25,143	\$25,927	\$26,694	\$27,435	\$28,162	\$28,875	\$29,566	\$30,235	\$30,889	\$31,532	\$31,550	\$31,564	\$31,576	
12	Option 3: Bidder 2		\$1,407	\$2,651	\$2,272	\$5,792	\$9,112	\$12,249	\$15,224	\$18,071	\$20,772	\$23,339	\$25,787	\$28,120	\$30,167	\$31,952	\$33,693	\$35,409	\$37,082	\$38,712	\$40,324	\$41,895	\$43,428	\$44,940	\$46,418	\$46,494	\$46,557	\$46,609	
13																													
14	x 3) Summary chart																												



ATCO Electric Yukon (AEY) 2023 - 2024 General Rate Application (GRA)																												
Line No.	CIS Project Cumulative Present Value Analysis																											
		(0)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	
	Option 2: Bidder 1	yr	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
4	x Capital structure																											
5		Rate																										
6		Ratio																										
7		B.T. Cost																										
8		A.T. Cost																										
9		Debt	5.09%	59.57%	3.03%	3.03%																						
10		Preferred	0.00%	0.00%	0.00%	0.00%																						
11		Common	9.00%	39.73%	4.90%	3.58%																						
12	TOTALS				100.0%	7.93%	6.61%																					
13	Income Tax	27.0%																										
14	x Escalation																											
15	Capital	2.00%																										
16	O & M	2.00%																										
17	x Capital spending (\$000s)																											
18	Description	ISD (Year)	Deprec'n (yrs)	CCA (%)																								
19	Installation costs	2022	10	100%																								
20	(escalated or 2%)																											
21	x Incremental O&M spending (\$000s)																											
22	Description																											
23	Annual operating costs																											
24	(escalated or 2%)																											
25																												
26	x Installation costs detail (Expand with 'x')																											
27	Description	Escalation Rate	CCA (%)																									
28	ISD (Year)																											
29	Depreciation	10.00%																										
30	CCA Rate	100%																										
31	AFUDC Opening	-	-	4	1,441	13,694	13,717	13,742	13,769	13,797	13,827	13,859	13,893	13,929	13,967	14,008	14,052	14,098	14,148	14,201	14,257	14,317	14,380	14,448	14,520	14,597	14,597	
32	Cap Add	4	1,390	12,206	23	25	26	28	30	32	34	36	39	41	44	47	50	53	56	60	64	68	72	77	-	-	-	
33	AT WACC	6.61%	0	46	48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
34	BT WACC	7.93%	-	-	13,694	23	25	26	28	30	32	34	36	39	41	44	47	50	53	56	60	64	68	72	77	-	-	
35	Equity	3.58%	-	-	6,847	6,859	24	26	27	29	31	33	35	37	40	42	45	48	51	54	58	62	66	70	75	38	-	
36	Debt	3.03%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
37	Preferred	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
38	Opening	-	-	-	13,009	11,662	10,314	8,965	7,615	6,263	4,911	3,557	2,203	846	173	184	196	209	223	237	253	269	287	305	325	268	216	
39	Closing	-	-	12,009	11,662	10,314	8,965	7,615	6,263	4,911	3,557	2,203	846	173	184	196	209	223	237	253	269	287	305	325	268	216	169	
40	Rate Base	-	-	6,505	12,336	10,988	9,639	8,281	6,939	5,587	4,234	2,880	1,524	510	179	190	203	216	230	245	261	278	296	315	297	242	192	
41	Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
42	Tax Treatment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
43	Equity & Preferred	-	-	-	233	441	393	345	296	248	200	151	103	55	18	6	7	8	9	9	10	11	11	11	9	7	7	
44	CCA	-	-	-	(13,694)	(23)	(25)	(26)	(28)	(30)	(32)	(34)	(36)	(39)	(41)	(44)	(47)	(50)	(53)	(56)	(60)	(64)	(68)	(72)	(77)	-	-	
45	Earnings for Tax	-	-	-	(12,777)	1,788	1,741	1,694	1,647	1,599	1,552	1,505	1,458	1,411	691	(5)	(3)	(6)	(9)	(16)	(21)	(27)	(31)	(38)	(47)	61	54	
46																												
47	Revenue Requirement																											
48	Depreciation	-	-	-	685	1,371	1,373	1,376	1,378	1,381	1,384	1,388	1,391	1,395	714	32	35	37	39	42	44	47	50	54	57	57	52	47
49	Debt	-	-	-	197	374	333	292	251	210	169	128	87	46	15	5	6	6	7	7	7	8	8	9	10	9	7	6
50	Equity	-	-	-	233	441	393	345	296	248	200	151	103	55	18	6	7	8	8	9	9	10	11	11	11	9	7	
51	Tax	-	-	-	(4,736)	661	644	626	609	592	574	557	539	522	256	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	25	23	20
52	Asset 1 Revenue Requirement	-	-	-	(3,611)	2,847	2,743	2,639	2,535	2,431	2,328	2,224	2,121	2,017	1,003	42	45	48	51	55	58	62	66	70	75	101	91	80
53																												
54																												
55	Depreciation Matrix																											
56	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
57	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
58	(2)	-	-	-	685	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	685	
59	(3)	-	-	-	685	686	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,371	
60	(4)	-	-	-	685	686	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,373	
61	(5)	-	-	-	685	686	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,376	
62	(6)	-	-	-	685	686	2	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,378	
63	(7)	-	-	-	685	686	2	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,381	
64	(8)	-	-	-	685	686	2	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,384	
65	(9)	-	-	-	685	686	2	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,388	
66	(10)	-	-	-	685	686	2	3	3	3	3	3	3	4	-	-	-	-	-	-	-	-	-	-	-	-	1,391	
67	(11)	-	-	-	685	686	2	3	3	3	3	3	3	4	4	-	-	-	-	-	-	-	-	-	-	-	1,395	
68	(12)	-	-	-	686	2	3	3	3	3	3	3	4	4	4	-	-	-	-	-	-	-	-	-	-	-	714	
69	(13)	-	-	-	2	3	3	3	3	3	3	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	50	
70	(14)	-	-	-	-	-	3	3	3	3	3	4	4	4	4	4	5	-	-	-	-	-	-	-	-	-	35	
71	(15)	-	-	-	-	-	-	3	3	3	3	4	4	4	4	4	5	5	-	-	-	-	-	-	-	-	37	
72	(16)	-	-	-	-	-	-	-	3	3	3	4	4	4	4	4	5	5	5	-	-	-	-	-	-	-	39	
73	(17)	-	-	-	-	-	-	-	-	3	3	4	4	4	4	4	5	5	5	5	-	-	-	-	-	-	42	
74	(18)	-	-	-	-	-	-	-	-	-	3	4	4	4	4	4	5	5	5	5	5	6	-	-	-	-	44	
75	(19)	-	-	-	-	-	-	-	-	-	-	4	4	4	4	4	5	5	5	5	5	6	6	-	-	-	47	
76	(20)	-	-	-	-	-	-	-	-	-	-	-	4	4	4	4	5	5	5	5	5	6	6	7	-	-	50	
77	(21)	-	-	-	-	-	-	-	-	-	-	-	-	4	4	4	5	5	5	5	5	6	6	7	7	-	54	
78	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4	5	5	5	5	5	6	6	7	7	7	57	
79	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-													

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

[illegible]

September 28, 2023

AEY-YUB-068

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-068

Reference: 2023-24 GRA, Sections 9.7 and 9.9, General Property Plant and Equipment, PDF pages 178 and 179-180; Schedule 9.2.; Business Case #24, PDF pages 13-16

Issue: Asset Management

Preamble: The Board requires further information.

Request:

- (a) Table 1 from the BC#24 (PDF page 14) lists five categories where AEY is compared to a peer group. For each of the categories, please describe how AEY has failed to meet any reliability measures, where customer service has been negatively impacted or where AEY has incurred additional costs because it did not implement this Asset Management Program.
- (b) The Evaluation of Viable Alternatives (PDF page 15) states: "The Alternative is Status Quo, which will not address any of the issues identified in the METSCO report and will lead to AEY falling further and further behind its peers." Is the appropriate measure where AEY ranks relative to other utilities or is it the level of service AEY provides to its customers? Please explain.

Response:

- (a) METSCO Energy Solutions Inc. provided a comprehensive evaluation of AEY for each of these categories and documented missed opportunities, or gaps, relative to peers. These gaps correspond to improvement opportunities in the roadmap. See below table, for each category and a reference in the Appendix of the business case that describes the benefits of short-term step-wise improvement in asset management maturity.

Table 1: METSCO Report Categories

Category of Asset Management	METSCO Energy Solutions Inc. Report Heading
Capital Planning	3.2.1.3
Maintenance & Operations	3.2.2.3
Records Management	3.2.3.3
Finance and Corporate Reporting	None
Enterprise Risk Management	3.2.5.3

Furthermore, benefits of medium- and long-term actions in the roadmap are described specifically in Table 4-3.

This structured improvement program would help articulate and align reliability objectives, customer service expectations, cost performance, and other important business and strategic goals under a framework of defined organizational values and asset management principles. The purpose of asset management for physical infrastructure is to coordinate the right asset investments to achieve strategic objectives while balancing costs, opportunities, and risks. AEY is recommending this initiative to face upcoming challenges of aging infrastructure, loss of knowledge (i.e., demographics), grid automation and modernization, and changing customer profiles with a methodical and sequenced approach to improvements in the way we work. AEY believes implementing the asset management roadmap will also help Yukon ratepayers understand how AEY is delivering on its broad mandate in more specific terms.

- (b) When benchmarked against its peers, AEY ranks below in broad categories of capital planning, maintenance & operations, records management, finance & corporate reporting, and enterprise risk management. This is indicative of adoption and progress of the asset management principles within similar sized utilities in order to meet the challenges and expectations these businesses face. The measure of where AEY ranks in these categories to its peers, with similar customer profiles and infrastructure challenges, and the level of service that AEY provides

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to its customers are not mutually exclusive. AEY would expect that reliability, affordability, and customer experience are level of service standards shared amongst its peers and it is reasonable to infer a direct correlation between peer performance in these respects to the maturity of their asset management program, based upon the benefits that METSCO Energy Solutions Inc. described within the report (Table 2-1 and footnote 2).

September 28, 2023

AEY-YUB-069

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-069

Reference: 2023-24 GRA, Section 10, Schedule S10.1, Line No. 30

Issue: Income taxes

Request:

- (a) Are the deductible items and amounts for income tax purposes largely up to the discretion of management? Please explain.
- (b) What is “ES&G & Other Deductible Costs”?
- (c) How are actual ES&G & Other Deductible Costs determined?
- (d) How are ES&G & Other Deductible Costs forecast?
- (e) Does the “ES&G” portion of “ES&G & Other Deductible Costs” follow capital expenditures? That is, as capital expenditures increase, so would ES&G costs increase?
- (f) If the “ES&G” portion of “ES&G & Other Deductible Costs” follow capital expenditures, should they increase with the projected capital expenditures for each of the test years 2023 and 2024? Please explain.
- (g) For the years 2016 and 2017, please explain why the actual deductible amounts for ES&G & Other Deductible Costs are higher than the approved amounts for that line item.
- (h) If actual income tax expense is lower than forecast, is that a benefit to the shareholder?

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Response:

- (a) While management has some discretion respecting income tax deductions, AEY follows Canada Revenue Agency tax rules and guidelines with respect to deductible items and amounts for income tax purposes.
- (b) Similar to AEY's previous GRAs, ES&G and Other Deductible Costs have been deducted from Utility Earnings before Tax for purposes of calculating Taxable Income.

ES&G (Engineering, Supervision and General) costs are general in nature and not attributable to specific projects. These costs are allocated to the construction of capital projects as an overhead charge, such as telephone, printing and stationery, travel and accommodations, equipment hours, clerical support, drawings, and other project document management as well as the development and maintenance of engineering standards. These expenditures are analogous to overhead costs that would normally be charged by a contractor to engineer, procure, and construct similar projects.

Other Deductible Costs include one-time adjustments such as mid-term incentives and short-term incentive program payouts in relation to ES&G charged as capital support.

- (c) As outlined in part (b) above, actual ES&G costs are costs that relate to the construction of capital projects. These costs are captured in ES&G accounts in AEY's general ledger and are allocated to capital projects, on a monthly basis, as capital overhead. Other Deductible Costs are not recurring and are determined when payments are incurred.
- (d) ES&G and Other Deductible Costs are forecast by reviewing historical actuals, as explained in part (b) and (c) above, and applying trending analysis and using the best information available at the time of developing the forecast. For example,

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additional review and analysis could include the addition of a capital project that is not typical compared to the norm, or a new initiative that has not previously been contemplated. Similarly, AEY's forecast has been adjusted for large customer projects, in the test period, which differs from the historical trend.

- (e) The relationship between ES&G and capital expenditures is not linear. The estimated capital expenditures, to construct a capital asset, are comprised of different types of costs such as internal labor, materials, and contractors which do not have an impact on capital support (ES&G). The capital expenditures, in a given period, may increase (or decrease) due to higher (or lower) material costs or due to delays of project execution, which do not directly relate to the increased need for capital support (ES&G).
- (f) Forecast ES&G costs are determined by reviewing the anticipated allocation of labour related costs to capital, less the portion directly allocated to large projects plus a historical average of other non-labour costs. Actual ES&G and Other Deductible Costs came in higher than the approved amounts mainly due to increased needs for capital support for Generation and Construction Projects in 2016 and 2017. This increase also included more support for AEY's renewables capital portfolio along with increased system investment for customer connections. The costs, previously anticipated to be charged to general capital overhead, were directly charged to the respective programs and are included in the undepreciated capital costs eligible for CCA deductions.
- (g) While lower actual income tax amounts (versus forecast) may be to the benefit of shareholders, customers also benefit over the longer term, as trends in actual income tax expenses are reviewed and help form the basis for forecasting future income tax expenses included in revenue requirement and rate setting in AEY's GRAs.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023**

AEY-YUB-070

Reference: 2023-24 GRA, Section 11, Prior Board Directions, PDF pages 11-12, 184-185 and 191

Issue: AEY response to Board Order 2017-01, Appendix A, dated April 27, 2017, Direction No. 16, paragraph 278

Quote: GRA, PDF page 184-185:

Direction No. 16, Reference: Paragraph 278

Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings. (Emphasis added)

Request:

- (a) For the five most costly improvement project business cases submitted by AEY in its GRA, please provide references for each project to where AEY has included "the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs."
- (b) For each project (Preventative System Performance, Note 1, and Corrective System Performance, Note 2) identified in Section 11 – Attachment 11.2, Direction No. 16, Reference: Paragraph 278, please provide a reference to the applicable

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business case number from those submitted by AEY in its 2023-24 GRA and also the corresponding line no. on GRA Schedule S9.2 for that project.

Response:

- (a) The five most costly distribution improvement project business cases with references to the performance deficiency are:
- a. BC#12,26 Annual ROW Widening para 6. The selection of areas uses feeder specific statistics as an input.
 - b. BC#25 New Substations Mayo Road and Whistle Bend paras 2&4. This project addresses the capacity issue.
 - c. BC#30 6L19 Voltage Improvement paras 2-4,6 This project addresses the low voltage issues.
 - d. BC#29 Old Crow Voltage Improvement paras 2-3,5. This project addresses the low voltage issues.
 - e. BC#05 3 Phase Hotsprings Road para 5. This project addresses the system balance issue.

As the projects identified above are preventative rather than corrective, AEY has provided its load growth KPI report used to help determine the need for the distribution improvements in the area. Please refer to AEY-YUB-070(a) Attachment 1.

- (b) Please refer to AEY-YUB-070(b) Attachment 1.

Summary

Less than 20% capacity remaining

Less than 10% capacity remaining

* All Values are in kVA

Arkell							
	Actual	Forecasted					
Percent Increase 2.72%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S8615 Normalized Load	3428	4380	4500	4622	4748		
S8619 Normalized Load	3068	3017	3099	3184	3270		
Transformer 1 Normalized Load	6266	7398	7599	7806	8018		
Regulator 1 Remaining Capacity	11055	9923	9721	9515	9302	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	3734	2602	2401	2194	1982	Transformer Rating	10000

Laberge							
	Actual	Forecasted					
Percent Increase 2.06%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S3600 Normalized Load	5600	5715	5833	5953	6075		
S8306 Normalized Load	1975	2016	2057	2099	2143		
Transformer 1 Normalized Load	7287	7730	7890	8052	8218		
Regulator 1 Remaining Capacity	10034	9590	9431	9268	9102	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	2713	2270	2110	1948	1782	Transformer Rating	10000

Lewes							
	Actual	Forecasted					
Percent Increase 0.58%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S6817 Normalized Load	2830	2807	2823	2839	2856		
S6822 Normalized Load	2139	2250	2263	2276	2289		
Transformer 1 Normalized Load	4851	5056	5086	5115	5145		
Regulator 1 Remaining Capacity	3809	3604	3575	3545	3515	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	2649	2444	2414	2385	2355	Transformer Rating	7500

Logan							
	Actual	Forecasted					
Percent Increase 2.69%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S9877 Normalized Load	1950	2122	2179	2237	2297		
S9878 Normalized Load	2677	2789	2864	2941	3020		
Transformer 1 Normalized Load	4447	4911	5043	5178	5318		
Regulator 1 Remaining Capacity	12874	12410	12278	12142	12003	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	5553	5089	4957	4822	4682	Transformer Rating	10000

Macrae							
	Actual	Forecasted					
Percent Increase 1.76%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S5953 Normalized Load	1861	1893	1927	1961	1995		
S9833 Normalized Load	4416	4494	4573	4654	4736		
Transformer 1 Normalized Load	6082	6387	6500	6614	6731		
Regulator 1 Remaining Capacity	2578	2273	2160	2046	1930	Regulator Rating (200A)	8660
Transformer 1 Remaining Capacity	3918	3613	3500	3386	3269	Transformer Rating	10000

Mountain View							
	Actual	Forecasted					
Percent Increase 2.52%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S8354 Normalized Load	1091	1118	1147	1176	1205		
S8358 Normalized Load	5630	5771	5917	6066	6219		
S8471 Normalized Load	1059	1086	1113	1141	1170		
Transformer 1 Normalized Load	7780	7976	8177	8383	8594		
Regulator 1 Remaining Capacity	1091	685	484	278	66	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	2431	2024	1823	1617	1406	Transformer Rating	10000

Porter Creek							
	Actual	Forecasted					
Percent Increase 2.12%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S9402 Normalized Load	2867	3101	3166	3233	3302		
S9403 Normalized Load	4189	4278	4369	4461	4556		
Transformer 1 Normalized Load	6772	7379	7535	7695	7858		
Regulator 1 Remaining Capacity	1888	1282	1125	966	802	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	3228	2621	2465	2305	2142	Transformer Rating	10000

Riverdale							
	Actual	Forecasted					
Percent Increase 1.9%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S9400 Normalized Load	2197	2386	2431	2477	2524		
S9401 Normalized Load	933	962	980	999	1018		
Transformer 1 Normalized Load	2985	3348	3412	3476	3543		
Regulator 1 Remaining Capacity	5675	5312	5249	5184	5118	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	4515	4152	4088	4024	3957	Transformer Rating	7500

Selkirk							
	Actual	Forecasted					
Percent Increase 2.72%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S9977 Normalized Load	4675	4803	4934	5068	5207		
Transformer 1 Normalized Load	4675	4803	4934	5068	5207		
Regulator 1 Remaining Capacity	3985	3858	3727	3592	3454	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	5325	5197	5066	4932	4793	Transformer Rating	10000

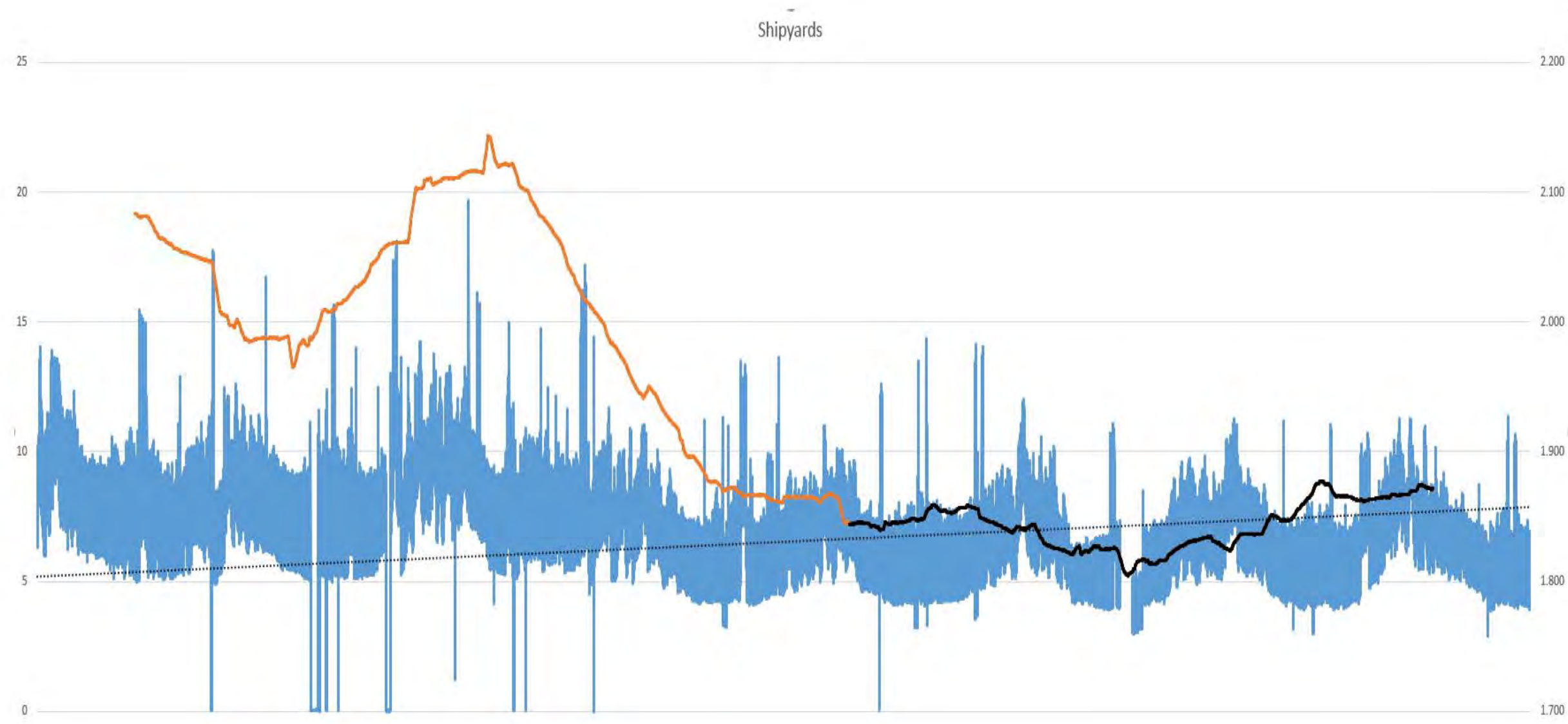
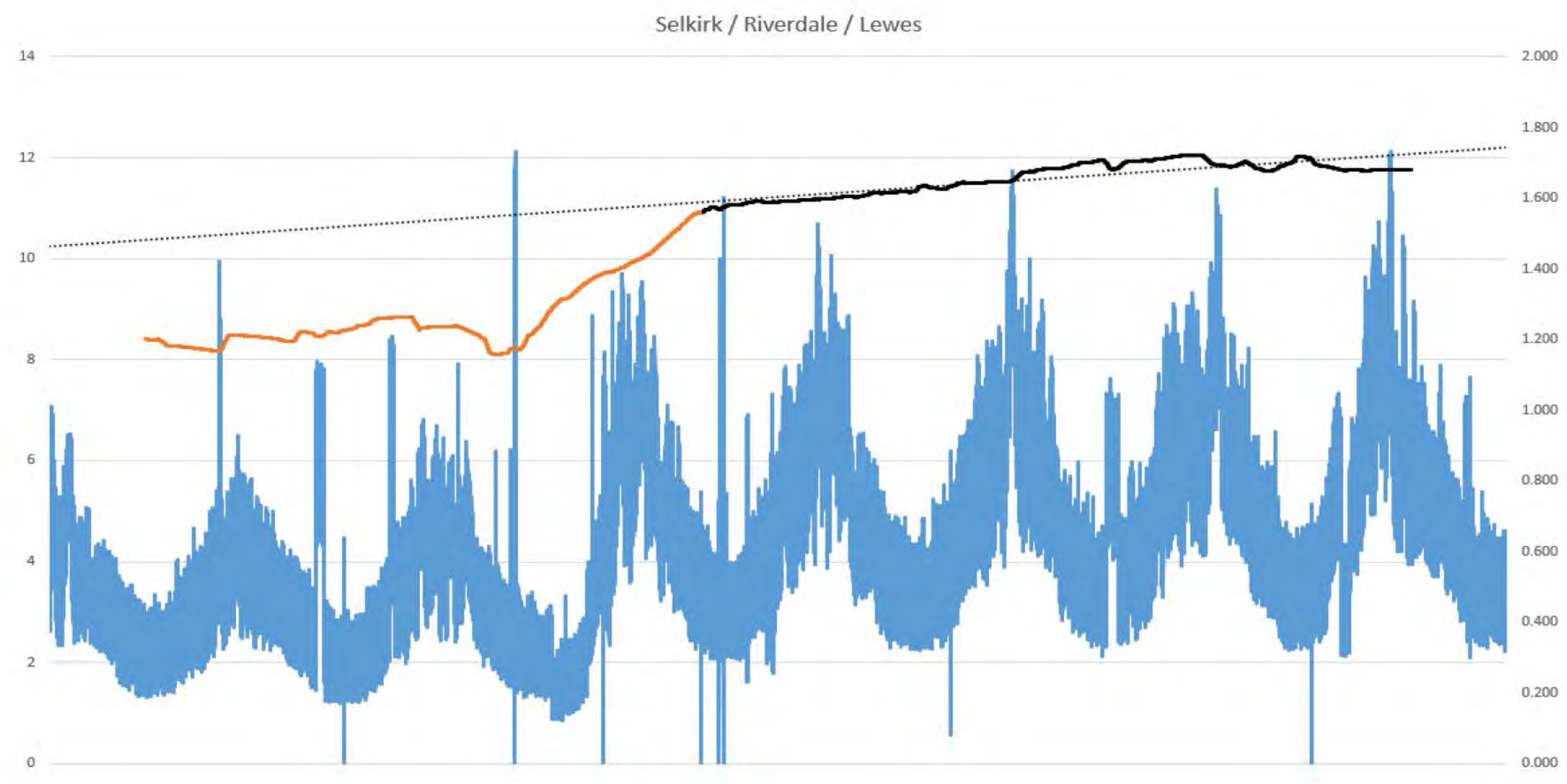
Services							
	Actual	Forecasted					
Percent Increase 0%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S7191 Normalized Load	3676	3676	3676	3676	3676		
Transformer 1 Normalized Load	3676	3676	3676	3676	5207		
Regulator 1 Remaining Capacity	5144	4984	4984	4984	4984	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	3984	3824	3824	3824	3824	Transformer Rating	7500
S7192 Normalized Load	3268	3268	3268	3268	3268		
S7193 Normalized Load	1374	1374	1374	1374	1374		
Transformer 2 Normalized Load	4520	4642	4642	4642	4642		
Regulator 2 Remaining Capacity	4140	4019	4019	4019	4019	Regulator Rating (400A)	8660
Transformer 2 Remaining Capacity	2980	2859	2859	2859	2859	Transformer Rating	7500

Shipyards							
	Actual	Forecasted					
Percent Increase 0.99%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S1020 Normalized Load	3720	3757	3794	3832	3870		
S1023 Normalized Load	3607	3643	3679	3715	3752		
Transformer 1 Normalized Load	6879	7400	7473	7547	7622		
Regulator 1 Remaining Capacity	1781	1260	1187	1113	1038	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	3121	2600	2527	2453	2378	Transformer Rating	10000
S1011 Normalized Load	3550	3585	3620	3656	3692		
S1016 Normalized Load	1731	1748	1765	1782	1800		
Transformer 2 Normalized Load	4863	5333	5385	5439	5493		
Regulator 2 Remaining Capacity	3797	3328	3275	3222	3168	Regulator Rating (400A)	8660
Transformer 2 Remaining Capacity	5137	4667	4615	4561	4507	Transformer Rating	10000

Whistlebend							
	Actual	Forecasted					
Percent Increase 11.26%	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027		
S3431 Normalized Load	593	660	735	817	909		
S3432 Normalized Load	2518	2802	3117	3468	3858		
Transformer 1 Normalized Load	3088	3462	3852	4285	4768		
Regulator 1 Remaining Capacity	14233	13859	13469	13035	12553	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	6912	6538	6148	5715	5232	Transformer Rating	10000
S3433 Normalized Load	5785	6436	7161	7967	8864		
S3434 Normalized Load	127	142	158	175	195		
Transformer 2 Normalized Load	5674	6578	7318	8142	9059		
Regulator 2 Remaining Capacity	11647	10743	10002	9178	8261	Regulator Rating (400A)	17321
Transformer 2 Remaining Capacity	4326	3422	2682	1858	941	Transformer Rating	10000

Substation	1yr moving avg	1yr moving avg with peak factor	Notes
Arkell	1.94%	2.72%	S150 SCADA (2015-2022) for the Arkell feeder supplid by YEC. This substation is servicing a mature residential subdivision, as well as some commercial along Range Road. No major development so moderate growth is expected
Laberge	1.47%	2.06%	This substation is servicing a large mature residential and industiral area that includes Hot Springs Road, the Alaska Hwy, and Kulan industrial. Therefore, a moderate yearly growth is to be expected. YEC SCADA data used
Lewes	0.42%	0.58%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Logan	1.92%	2.69%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Macrae	1.25%	1.76%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Mountain View	1.80%	2.52%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Porter Creek	1.52%	2.12%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Riverdale	1.35%	1.90%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Selkirk	1.95%	2.73%	Load from Services and Shipyards was shifted to Selkirk, this can be seen in the graph below. Data provided by YEC for S150 was used for the feeder that supplies Selkirk, Lewes, and Riverdale. The growth rate for Selkirk was calculated by taking the slope of the S150 feeder regression, minus the slope of the Riverdale regression, minus the slope of the Lewes regression. The remaining value is the slope of what would be the Selkirk regression.
Services	0.00%	0.00%	Both ATCO and YEC SCADA data show a steady decrease in load over the last four years (-5.19% and -3.56% respectively). There's uncertainty around why the decrease is occuring. Temporary load shifting within the data between Services, Arkell, Mountain View, and Porter Creek can all be accounted for.
Shipyards	0.71%	0.99%	Load from Shipyards was shifted to Selkirk. As seen in the graph below, the trendline was taken for the period of time after the load shift and once the 1 year moving average had stabalized.
Whistlebend	8.04%	11.26%	Growth at this substation is rapid due to on going development. Since ATCO has first hand knowledge of expected growth from the number of houses that are built each year, one of two approaches can be taken: Use the yearly growth percentage found from the moving average or apply a set load increase based on total number of homes built in a given year multiplied by average load per home. YEC SCADA data was used.

*Note regarding Laberge and Whistlebend - The growth percentage found from ATCO SCADA data subjectly high, whereas the growth seen from the YEC SCADA data for the feeder supllying Laberge and Whistlebend looked to be closer to what would be expected. To break up the YEC feeder data into its respective substations, the weight of growth percentages for each substation from ATCO SCADA was applied to the YEC data.



ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Direction No. 16, Reference: Paragraph 278

Line No.	System Improvement Projects	2018	2019	2020	2021	2022	2023	2024	Annual Program
1									
2	System Performance - Preventative ⁽¹⁾	1	2	3	1	2	3	10	2
3	System Performance - Corrective ⁽²⁾	2	-	1	-	-	1	1	-
4	Life Extension	3	-	6	2	4	2	3	1
5	System Replacement	2	1	1	-	2	-	1	4
6	Customer Driven and/or Assigned	1	3	3	4	5	1	4	-

1. Preventative System Performance

Preventative system performance projects are determined based on operational drivers and address potential system imbalance, voltage or capacity issues before degradation of system or outages occur.

Project Name	I/S Year	Driver	Business Case	Line on 9.2	Note
Annual Right of Way Widening	Annual	Feeder-specific stats are used for ROW selection	#12, #26	182	
General Clearance Upgrades/Fixes	Annual	Conductor clearance concerns, trespass issues		186	
AEY 102 Lambert Encroachment	2024	Clearance issue		206	
3 Phase Hotsprings Rd	2020	System balance	#05	218	
AEY Old Crow Volt Issues-Loop	2019	System voltage		227	
AEY 25kV A.Hwy Hamilton Tie	2018	System alternative feed	#11	228	
Alaska Highway to McIntyre Tie Stage 2	2019	System alternative feed	#11	229	
Teslin Substn Metering	2018	System power quality		230	
AEY SCADA Switch at Pinerdg	2023	Operational capability		238	1
Carcross Road Voltage Improvements	2020	System voltage	#17	247	
Riverdale Load Sectionalizing	2020	Operational capability		256	
AEY Hamilton to Alaska Highway 25kV Tie	2021	System alternative feed		262	
AEY New Subst Mayo Rd	2024	Capacity	#25	266	2
AEY Voltage Issues Gold Road	2022	System voltage		267	
New Substation Mayo Road	2024	Capacity	#25	272	2
Reconductor Mayo Rd Mainline - Stage 3	2022	Protection and capacity	#06	273	
AEY Dogwood voltage improvement	2024	Voltage		278	
AEY DWCI - New 12.5kV substation	2026	Capacity		279	
AEY New Substation Whistle Bend - Leota	2025	Capacity	#25	281	
AEY SCADA Pineridge Switch	2023	Operational capability		283	1
AEY Voltage Improvement Destruction Bay	2023	Voltage		286	
AEY Hillcrest Voltage Improvement	2024	Voltage		289	
AEY Pelly Crossing Voltage Improvement	2024	Voltage		290	
Power System Assessment - YEC and AEY	2024	Capacity		292	
AEY 6L19 voltage improvement	2024	Voltage	#30	296	
AEY Carcross PQ monitoring	2024	System power quality		299	
Old Crow voltage improvement - reconductor	2024	Voltage	#29	301	

Note 1 - Line 21 is the actual costs for the SCADA Switch at Pineridge expended prior to the test years and line 32 is the forecast cost in the test year

Note 2 - Line 25 is the actual planning expenditure for the Mayo Road Substation while line 27 is the forecast cost for the Mayo Road Substation.

2. Corrective System Performance

Corrective system performance projects address system performance issues.

Project Name	I/S Year	KPI	Post Improvement KPI	Business Case	Line on 9.2
AEY CCC Rd Rebuild	2018	Outage count S6709 (2015-2018): 8	Outage Count S6709 (2019-2022): 0		217
AEY Wtsn Lk Vertical Strcts	2018	SAIFI (Watson Lake - 2017 System Wide): 5.25	SAIFI (Watson Lake - 2019 System Wide): 8.9		233
AEY Cowley Rd Rebuild SKH	2020	Outage count S6711 (2015-2018): 5	Outage Count S6711 (2019-2022): 0		236
AEY Choutla Long Span Rebuild	2023	SAIFI (5L600, all outages, 2021): 0.19	Project not completed yet		277
Watson Lake 5L621 Upgrade	2024	SAIFI (Watson Lake - 2017 System Wide): 5.25	Project not completed yet		291