ATCO Electric
YUKON

# 2023-2024 General Rate Application (GRA)

S17 HLC Breaker Replacement

2018-2022 Business Case #04

## Executive Summary

1. Replacement of two HLC minimum oil circuit breakers at S17 McIntyre Substation required to address end-of-life circuit breakers that present safety, and operational risks.

## Background

2. Existing in-service HLC breakers are nearing end-of-life. Replacement parts are no longer reliably obtainable. McIntyre Substation recently had a failure of an HLC breaker which caused significant downtime to that particular breaker. The vendor no longer supports this equipment.

## Project Description

3. The project will decommission existing breakers and replace with modern vacuum-operated low-maintenance circuit breakers.

## Project Schedule and Costs

**Table 1: Project Schedule & Cost**
**($000)**

| | Target Completion Date | Actuals Cost |
|---|---|---|
| Procurement and Completion | 2020 | 136 |

## Business Drivers and Benefits

4. Lack of vendor support and spares. Reduced reliability.

5. Breakers are electrical safety devices designed to de-energize equipment in fault conditions. Failure of a breaker to operate, or a slow operation, increases the likelihood that equipment damage can occur. It also increases the risk that the fault causes some type of damage such as a wildfire, third party property damage or a human injury. The HLC breakers in McIntyre Substation are important delivery points for energy into the AEY distribution system. If the project is not done there is a greater risk of long, widespread outages to customers. Replacement of the breakers at the McIntyre

Substation will result in increased reliability and continued support and sparing from the manufacturer.

**Evaluation of Viable Alternatives**

Alternative 1 Status Quo

6. Unplanned maintenance on these breakers is relatively expensive compared to planned and coordinated replacements. Some of the units already have had multiple unplanned repairs. As they age and deteriorate, the probability of failure increases, and they become more likely to cause outages and require more unplanned maintenance.

Alternative 2 Refurbish Breakers

7. There is little technical support available from the manufacturer and in most cases, replacement parts are no longer available.

Alternative 3 Replace Breakers

8. This option takes measures to address the identified needs by replacing the identified breakers with new breakers. New breakers will operate reliably and safely and are expected to operate for over 40-years.

**Recommendation**

9. Alternative 3 - Replace existing oil circuit breakers with vacuum circuit breakers.

ATCO Electric
YUKON

# 2023-2024 General Rate Application (GRA)

Extend Three-Phase Line on Hotsprings Road

2018-2022 Business Case #05

## Executive Summary

1. The Takhini Hot Springs are a popular tourist destination approximately 30 km northwest of Whitehorse. The surrounding area has a variety of mixed-use development including agricultural land, rural residences, and the Eclipse Nordic Hot Spring resort. There is steady growth of electrical usage of between three-five percent annually over the past 10-years.

2. Currently, the area's electrical system is serviced by one single-phase distribution line. However, with the expected load growth of the system, the existing line is expected to be at capacity within five-years. AEY has evaluated five potential alternatives and is recommending replacing 4.5 km of single-phase line with three-phase to adequately meet the future needs of the area. The new three-phase line will increase the capacity of the Hotsprings Road line from 1,675 kVA to 2,750 kVA ensuring the security of supply for the area over the foreseeable future assuming four-five percent growth.

## Background

3. The existing distribution line consists of 2 km of three-phase main line and 6.8 km of single-phase main line from the Klondike highway north to the intersection of Takhini River Road. The Hotsprings road line is fed by S3600 in Laberge Substation. A single line diagram is attached in Appendix A.

4. The Hotsprings Road area is a popular commercial and residential location north-west of Whitehorse. This area services three customer types:

- The Eclipse Nordic Hot Spring Resort;
- Rural Residential Homes; and
- Agricultural Farm Lots.

5. Historical load growth at the Laberge substation is between three to five percent annually. A three-phase line balances load on all three phases rather than just one and provides better voltage and system protection.

| | |
|---|---|
| Seven-year Annualized Growth (2008-2015) | 4.6% |
| Three-year Annualized Growth (2012-2015) | 3.7% |

6. The present loads and feeder capacities of the substation and area distribution line are shown below in Table 1. Both locations have a long-term limiting factor as electrical system load continues to grow. System improvements will be required to accommodate continued load growth.

**Table 1: Present Feeder Capacities of the System**

| Location | Peak Load | Present Feeder Capacity | Limiting Factor |
|---|---|---|---|
| S3600 at Laberge Substation | 4,298 kVA | 5,950 kVA | Low voltage in Deep Creek Subdivision |
| S4017 – Three-Phase tap for Hotsprings Road at Klondike Highway | 1,108 kVA | 1,675 kVA | Low voltage downstream of S9812 inline switch on Hotsprings Road |

7. *Feeder Capacity* is the total amount of load that can be served before there is a risk to the security of supply in peak load scenarios. A *Limiting Factor* is the potential issue that does not allow a system to operate at a greater capacity; typical factors include low voltage, thermal limit for conductor, or thermal limit for equipment.

8. The present load on S4017, the Hotsprings Road distribution line, is 1,108 kVA. By applying the growth rate seen at the Laberge substation (three to five percent) to S4017, AEY can forecast the annual anticipated peak loads.

**Table 2: Forecasted Peak Load on S4017**

| Location | Forecast Growth Rate | Annual Forecasted Peak Load (kVA) | | | | | |
|---|---|---|---|---|---|---|---|
| | | 2017/2018 | 2018/2019 | 2019/2020 | 2020/2021 | 2021/2022 | 2022/2023 |
| S4017 | 4% | 1,108 | 1,402 | 1,448 | 1,496 | 1,546 | 1,598 |
| | 5% | 1,108 | 1,413 | 1,472 | 1,533 | 1,597 | 1,664 |

9. The peak loads include a single 250 kVA load addition for a new three-phase farm service in 2018/2019 in addition to the four percent growth. The 250 kVA load is not escalated in Table 2 but remains constant each year.

## Project Description

10. The preferred solution is to address the long-term security of supply in the Hotsprings Road area. With an anticipated 250 kVA load being added in 2018 and a five percent growth rate, the area's peak load will exceed the current system's capacity in 2023 or 2024. Installing a three-phase line will increase the capacity of the Hotsprings Road line from 1,675 kVA to 2,750 kVA.

11. The project would replace 4.5 km of the existing single-phase electrical line with a new three-phase line then transfer the customers' taps to the new line.

## Project Schedule and Cost

12. The total cost of this project is $393,935 and it was completed in 2019.

## Business Drivers and Benefits

13. Long-term load growth is the business driver behind this upgrade. By executing the improvement from single-phase to three-phase AEY will be able to serve the growing load on the Hotsprings Road. The new three phase line will increase the capacity of the Hotsprings Road distribution line from 1,675 kVA to 2,750 kVA.

14. Additional system benefits of the project include:

- **Improved protection performance** - Coordination between system devices is not optimal because of the high single-phase load. Balancing the load will improve coordination.
- **Reduced voltage unbalance** - Modelling shows that voltage unbalance exists but is within limits. The project will improve voltage unbalance for three-phase customers.

## Evaluation of Viable Alternatives

<u>Alternative 1 - Status Quo – Operate with Current System</u>

15. System will continue to operate utilizing the single-phase distribution line. Based on the load growth forecast in Table 2, the peak load of the system will begin to exceed the system capacity in 2023 or 2024. At this point, the system will need an emergency upgrade or there is the potential loss of electrical supply at peak load times.

Alternative 2 - Install 4.5 km of Three-Phase Distribution Line Along Hotsprings Road

16. Address the area's load growth by building 4.5 km of new three-phase distribution line along Hotsprings Road to balance the existing load and reduce voltage drop to the end of the line. Table 4 shows the new feeder capacity of S4017 at 2,750 kVA with the new line. This capacity is expected to handle the area's projected load growth for the foreseeable future.

17. This alternative is preliminarily estimated to cost $395,000.

**Table 4: New Three-Phase Feeder Capacity of the System**

| Location | Present Load | New Feeder Capacity | Limiting Factor |
|---|---|---|---|
| S4017 – Three-Phase Line | 1,108 kVA | 2,750 kVA | Low voltage upstream of three-phase regs R113, R114, R115 S3490, S3491, S3492 on Klondike Highway |

18. This alternative is recommended as it addresses the region's projected load growth for the foreseeable future at an appropriate cost.

Alternative 3 - Install a Single-Phase Voltage Regulator to Improve Voltage as Load Grows

19. To address the region's load growth, install a new single-phase regulator mid-way along the existing system on Hotsprings Road. The regulator would prevent end of line voltages from dropping to an unsafe level and service load growth in the region until 2024. This alternative is preliminarily estimated to cost $30,000.

**Table 5: New Feeder Capacity with a Single-Phase Voltage Regulator**

| Location | Present Load | New Feeder Capacity | Limiting Factor |
|---|---|---|---|
| S4017 – Single-Phase Line | 1,108 kVA | 1,800 kVA | Low voltage upstream of three-phase regs R113, R114, R115 S3490, S3491, S3492 on Klondike Highway |

20. This alternative has been rejected as it is a short-term resolution to the area's growth and the single-phase line would still need to be replaced by approximately 2023 or 2024.

Alternative 4 - Install 6.8 km of three-phase distribution line along Hotsprings Road

21. Address the region's load growth by building 6.8 km of new three-phase distribution line along Hotsprings Road to balance the current load and reduce voltage drop to the end of the line. This alternative is preliminarily estimated to cost $580,000.

**Table 6: New Feeder Capacity with 6.8 km of New Three-Phase Distribution Line**

| Location | Present Load | New Feeder Capacity | Limiting Factor |
|---|---|---|---|
| S4017 – New Three-Phase Distribution Line | 1,108 kVA | 2,900 kVA | Low voltage upstream of Three-Phase regs R113, R114, R115 S3490, S3491, S3492 on Klondike Highway |

22. This alternative was rejected because only 150 kVA capacity is gained beyond the preferred option for approximately $200,000 in additional costs.

Alternative 5 - Install 2.7 km of Three-Phase Distribution Line Along Hotsprings Road

23. Address the area's load growth by installing 2.7 km of new three-phase distribution line along Hotsprings Road to balance existing load and reduce voltage drop to the end of the line. This option would address the area's load growth until approximately 2028. This alternative is preliminarily estimated to cost $255,000, with the costs broken down below:

- Install 6.8 km of new three-phase line along Hotsprings road: $180,000;
- Install recloser: $45,000; and
- Reconnect customer taps to new line and salvage existing single-phase line: $30,000.

**Table 7: New Feeder Capacity after Three-Phase Extended on Hotsprings Road for 2.7 km**

| Location | Present Load | New Feeder Capacity | Limiting Factor |
|---|---|---|---|
| S4017 – New Three-Phase Distribution Line | 1,108 kVA | 2,150 kVA | Low voltage near S9812 on Takhini River Road |

24. This alternative was rejected, although it was considered a strong second option. The capacity increase does address the area's growth with costs of $140,000 below the preferred option. However, the capacity increase from Alternative 2 is expected to last for an additional five-six years. Therefore, from a long-term perspective, Alternative 2 will be the lower cost alternative.

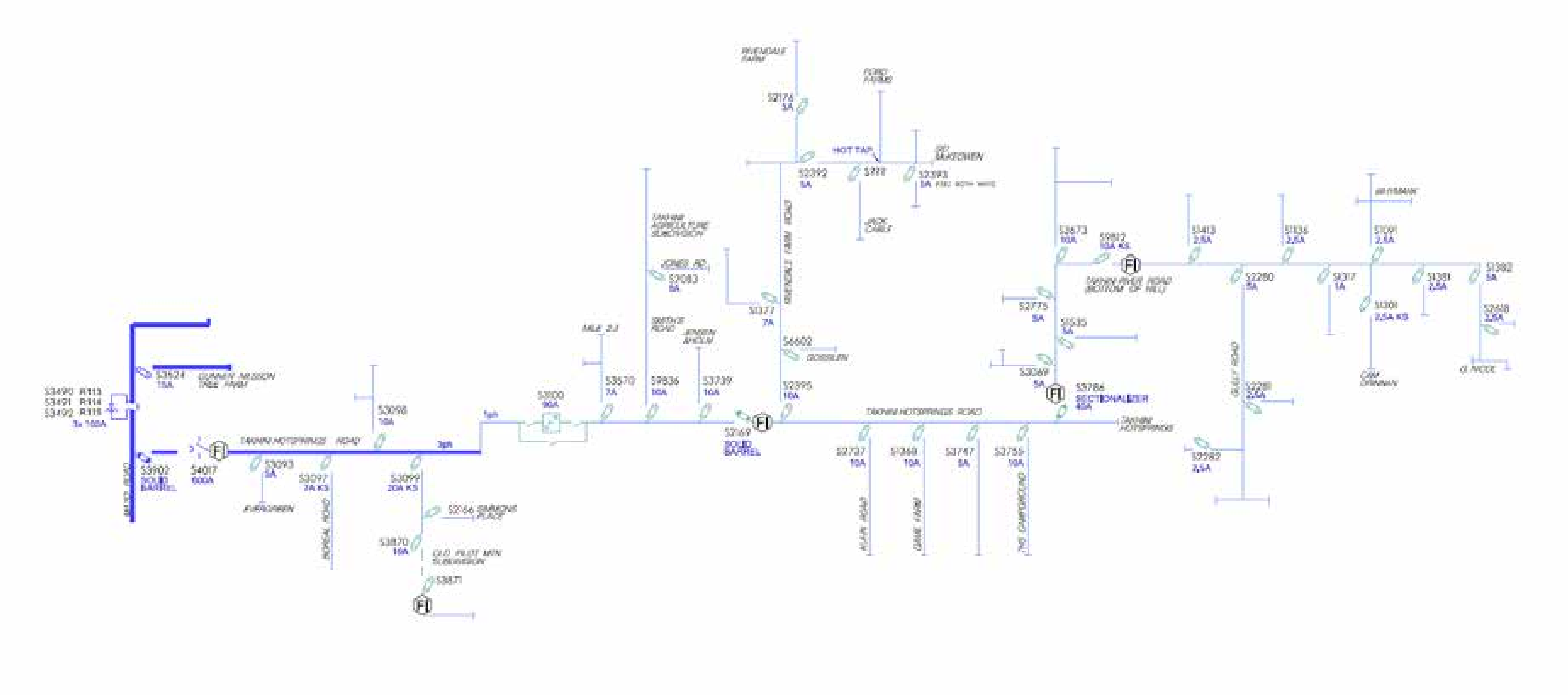
## Recommendation

25. The Hotsprings Road area is expected to have a peak load that exceeds the current system's capacity in 2023 or 2024. Delivering power safely is AEY's primary responsibility and maintaining the security of electrical supply in the Hotsprings region is the primary business driver for this alternative. To address the capacity constraint AEY recommends Alternative 2: the installation of a new 4.5 km three-phase distribution line along Hotsprings Road. This new line will increase the capacity of the system from 1,675 kVA to 2,750 kVA.

## Appendices

Appendix A Single Line Diagram

## Appendix A: Single Line Diagram



ATCO Electric
YUKON

# 2023-2024 General Rate Application (GRA)

Partial Reconductor Mayo Road

2018-2022 Business Case #06

## Executive Summary

1. The Mayo Road 25 kV mainline provides power to homes and farms north of Whitehorse. Upgrading small wire on the Mayo Road 25 kV mainline to 1/0 Aluminum-Conductor Steel-Reinforced Cable (ACSR) is required to increase upstream protection settings and provide adequate protection coordination. Without immediate action, the existing small wire will not be adequately protected, or the protection may trip on load.

2. To rectify this issue, AEY is recommending a partial reconductor of the Mayo Road 25 kV mainline from #6 ACSR and #4 ACSR to 1/0 ACSR to increase upstream protection settings and provide adequate protection coordination. Due to the age of the existing poles and other infrastructure on this line, segment replacement of affected poles is recommended.

## Background

3. Load growth downstream of this stretch of line has required larger fuses on branches of the 25 kV mainline. Upstream trip settings on S8686 have been increased in order to maintain proper protection coordination and are now greater than the rating of the conductor.

4. The existing conductor on the Mayo Road mainline is a mix of 5 km of #6 ACSR and 2 km of #4 ACSR cable. However, the existing protection setting is higher than the rating of #6 ACSR This trip setting is required to provide room for coordination (both fuses and relay curves) and prevent outages caused by tripping on load. Partially reconductoring the 25 kV line to 1/0 ACSR for this 7 km of line is required so that the conductor meets the protection settings.

5. Most of the existing poles were installed in the 1960s, with some in the 80s and 90s. These older poles are shorter and weaker than modern utility design practices would require.

## Project Description

6. AEY is recommending a partial reconductor of the Mayo Road 25 kV mainline from #6/#4 ACSR to 1/0 ACSR to increase upstream protection settings and provide adequate protection coordination.

7. The replacement is recommended for the 2 km of #4 ACSR from Takhini Switching Station to Vista Road and the 5 km of #6 ACSR north past Vista Road. The project will be staged over three-years to manage construction resources effectively.

## Project Schedule and Cost

**Table 1: Project Schedule & Cost**
**($000)**

| | Target Completion Date | Actuals |
|---|---|---|
| Reconductor 2.1 km #4 ACSR | 2020 | 126 |
| Reconductor 2.2 km #6 ACSR | 2021 | 138 |
| Reconductor 2.7 km #6 ACSR | 2022 | 162 |
| **Total** | | **426** |

## Business Drivers and Benefits

8. Higher trip settings will allow more room for coordination (both fuses and relay curves) which will reduce the scope of unplanned outages. The voltage will be improved (by an estimated two (2) taps on the upstream regulators) during peak loading allowing for additional downstream load to be added to the line. Finally, future outages due to planned construction work may be reduced.

## Evaluation of Viable Alternatives

Alternative 1 – Maintain Status Quo

9. Implement seasonal overcurrent settings on S8686 to match the thermal limit of the #6 ACSR in the summer and winter. Existing infrastructure does not support additional load growth nor any increases in protection settings. Preliminary estimated cost of dispatching a technician to manually adjust the settings seasonally is $2,000 (not including added maintenance cost) per year. This is not a viable long-term solution.

Alternative 2 – 5 km Reconductor of #6 Segment

10. Reconductor #6 ACSR to 1/0 for the 5 km section of distribution line north of Vista Road. This would resolve the current protection settings issue with the pick-up being greater than the conductor rating. However, this work does not provide adequate expansion for future load growth. Existing pick-up on breaker S8686 is 120A and the summer rating for #4 is 140A. Based on historical load growth, the breaker pick-up would need to be increased past the rating of #4 in five-years or less and would require an upgrade to 1/0 conductor at that time.

11. Preliminary estimated cost of this alternative is $400,000.

Alternative 3 – 7 km Reconductor of both #6 and #4 Conductor Segments

12. Reconductor both sections of the 2 km of #4 conductor from Takhini Switching Station to Vista Road and the 5 km of #6 conductor north past Vista Road.

13. Preliminary estimated cost of this alternative is $600,000.

Alternative 4 – No infrastructure replacement

14. This is not a viable alternative as existing pole strengths and heights do not support the new larger wire and modern requirements.

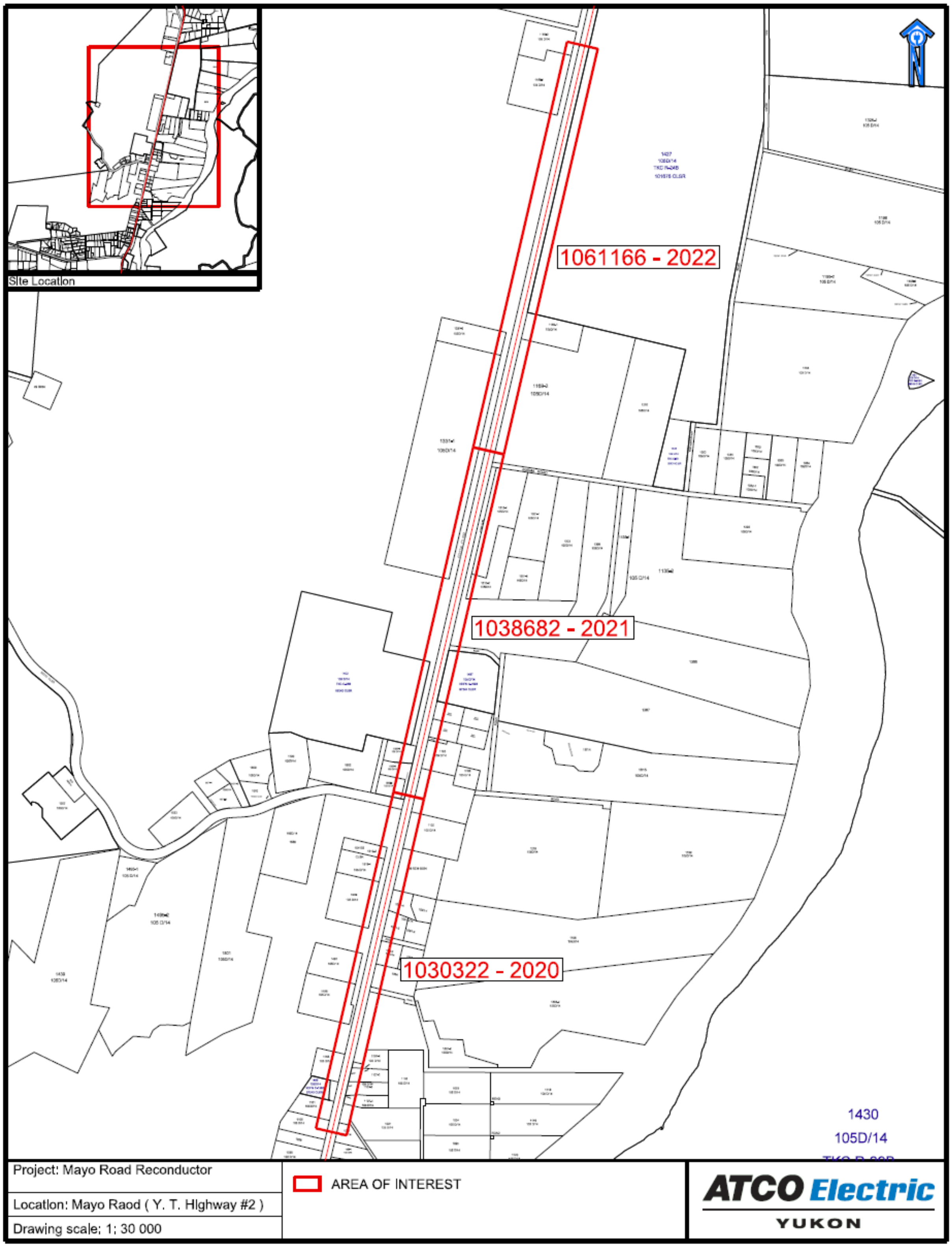
**Recommendation**

15. AEY has a duty to provide power safely and reliably. Operating a segment of distribution line that does not allow for future growth and has inadequate protection does not meet this mandate. To address this potential issue, AEY recommends Alternative 3 - reconductor of 7 km of the 25 kV Mayo Road mainline.

**Appendices**

Appendix A Mayo Road Reconductoring Map

## Appendix A: Mayo Road Reconductoring Map



ATCO Electric
YUKON

# 2023-2024 General Rate Application (GRA)

Replace Watson Lake Generating Units

2018-2022 Business Case #07

## Executive Summary

1. Through the Watson Lake Generating Facility, AEY is the sole source of power to approximately 1,000 customers across the Yukon and British Columbia. AEY has a duty to provide safe and reliable electricity service, which includes the prudent replacement of aging infrastructure.

2. Electricity usage in the service area continues to grow at an average pace of 1.33 percent annually, following the trend of general increased usage.

3. Operating a facility with aging infrastructure that, in specific circumstances, does not meet the peak load community is contrary to AEY's operating principles. Therefore, AEY is recommending the replacement of three outdated generating units at the Watson Lake Generating Facility.

## Background

4. The Watson Lake Generating Facility is currently the only source of power for the communities of Watson Lake (YK), Upper Liard (YK), and Lower Post (BC). AEY provides service to approximately 740 residential and 206 commercial customers in those communities. A map of the generating plants in the Yukon can be found in Appendix A. Upper Liard is 11 km west of Watson Lake and Lower Post is 23 km Southwest along the Liard River and below the 60$^{th}$ parallel.

5. This generating facility houses six diesel generating units. To allow for basic contingencies and plant maintenance, 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. In Watson Lake specifically, the peak load has grown by 24 percent over the past 20-years, although due to its small and variable economy, peak load growth has fluctuated between –11 and +13 percent year over year. In 2017, the peak demand exceeded the Firm Capacity, and this was addressed by replacing Unit 2 with a larger unit at its end-of-life.

6. Three generating units at the facility, Watson Lake Unit 1 (CUL 422 - installed in 1998), Watson Lake Unit 3 (CUL 352 – installed in 1991), and Watson Lake Unit 6 (CUL 423 – installed in 1998) are approaching the 100,000 operating hour mark. Canadian Off Grid Utilities Association planning criteria for 1200 RPM units recommends replacement after 90,000 to 126,000 hours of operation. 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.

7. The installation date and next major overhaul timing are shown in Table 1 below:

**Table 1: Unit Operating Metrics**

| Watson Lake Generating Facility | | | |
|---|---|---|---|
| **Unit #** | **Unit Name** | **Installation Date** | **Next Major Overhaul (Operational Hours)** |
| 1 | CUL 422 | 1998 | 92,310 |
| 3 | CUL 352 | 1991 | 93,721 |
| 6 | CUL 423 | 1998 | 89,853 |

8. Major overhauls require a capital budget of approximately $300,000 per engine for these units, based upon prior work completed. The intention is to complete the replacements for each prior to their planned major overhaul. Generator replacement is considered a low-risk project that AEY commonly undertakes. Recent executed projects of this nature include the CUL 257 Replacement in 2016 and CUL 258 Replacement in 2013.

**Project Description**

9. Over four-years, from 2018-2021, AEY will work with manufacturers and vendors to tender and procure three new generating units to replace the existing units. Each unit procured will have additional capacity to address Firm Capacity but will be constrained by the space limitations of the building.

10. For each generator, both the generator and the associated cooling, waste heat, and exhaust equipment will be removed from the Watson Lake facility. Then, a new diesel

generator as well as manufacturer-supplied cooling, waste heat, and exhaust equipment will be installed. After the installation of the new generator, the new equipment will be tied into Watson Lake facility's existing control system and switchgear. The replacement construction window is six to eight months, thereby leaving the facility at N-1 capacity – this is managed by scheduling each outage during summer months and lower loads.

### Project Schedule and Cost

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

| Description | Actuals | Completion Date |
|---|---|---|
| Unit 1 | 1,826 | February 2022 |
| Unit 3 | 1,890 | January 2020 |
| Unit 6 | 1,869 | January 2021 |
| **Total Costs** | **5,585** | |

### Business Drivers and Benefits

11. There are two business drivers for this project. The primary driver is continuing to provide the communities of Watson Lake, Upper Liard, and Lower Post with safe and reliable electrical service in N-1-1 contingent scenarios. The second driver is to ensure costs are managed appropriately and equipment is replaced at end of useful lifespan.

(1) <u>Increase Generating Capacity at the Watson Lake Generating Facility</u>

12. The load within the Watson Lake community is slowly growing. The Watson Lake Generating Facility had a peak load of 3,316 kW in 2017. To meet the community load, parallel operation of two or more generating units is required. It is AEY policy to ensure that its generating facility has sufficient capacity for N-1-1 scenarios; where power is still provided despite the loss of one operating unit while another unit is down for maintenance. The plant must have the Firm Capacity to meet peak load requirements. This N-1-1 contingency principle is practiced by both AEY and ATCO Electric in isolated facilities where parallel operation of multiple units is required.

13. As shown in Table 2, the current firm capacity of the Watson Lake facility is less than the 2017 peak recorded load (3,316 kW). Replacement of Units 1, 3, and 6 with larger capacity units would address this deficiency in generation capacity.

**Table 3: Watson Lake Generating Capacity**

| Watson Lake Generating Facility | | | |
|---|---|---|---|
| **Unit #** | **Unit Name** | **Current Unit Size (kW)** | **Final Unit Size (kW)** |
| 1 | CUL 422 | 800 | 1,050 |
| 2 | CUL 595 | 895 | 895 |
| 3 | CUL 352 | 1,000 | 1,245 |
| 4 | CUL 545 | 1,450 | 1,450 |
| 5 | CUL 466 | 650 | 650 |
| 6 | CUL 423 | 800 | 1,050 |
| **Installed Capacity (kW)** | | **5,595** | **6,340** |
| **Firm Capacity (kW)** | | **3,145** | **3,745** |

(2) Cost Effective Replacement Timing

14. The three generating units are due for major overhauls between 2019 (Unit 3) and 2020 (Units 1 and 6). Based on its operational expertise, AEY has seen less efficient operation and reliability of 1200 RPM generating units past the 100,000-hour mark. Typically, these units do not return to full operational reliability due to stresses and ageing that cannot be fully remediated or mitigated. The generating units require increased ongoing maintenance after this point.

15. AEY has been consistent in its approach of replacing of high mileage units rather than refurbishments due to reliability and return on investment concerns.

**Evaluation of Viable Alternatives**

Alternative 1 – Status Quo and Complete Major Overhaul Work

16. Continue operating as normal and perform the major overhaul on Units 1, 3, and 6. Based on previous operational experience, 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. Units will require more consistent maintenance, increased downtime, and will not operate at peak efficiency. The firm capacity of the

facility will not meet current peak loads and if loads continue to grow, this may result in a future unexpected outage. This alternative is not recommended.

Alternative 2 – Replace Units 1, 3, and 6

17. Replace the generating units and the associated cooling, waste heat, and exhaust equipment with new diesel generators and manufacturer supplied cooling, waste heat, and exhaust equipment, and integrate the new equipment into the facility's existing control system and switchgear. This addresses the current end of life concerns with the three units. With larger capacity units installed, the firm capacity of the Watson Lake Generating Facility will exceed peak loads as well as the expected growth (one percent year over year) for the next eight-years. It is expected to cost $4.95 million based on historical projects of this nature (CUL 257 Replacement in 2016 and CUL 258 Replacement in 2013). This alternative is recommended.

Alternative 3 – Use Different Units, Replace 3 Units with 1 Bigger One.

18. Replace three units with one larger one. Building configuration concerns aside and switching to a capacity N-1 model, the remaining units would only have a firm capacity of 3,095 kW which is below the observed peak. Additionally, having large steps between generator sizes creates operational issues. AEY aims to operate the units with an average capacity of 70 percent to meet manufacturers' specifications and maintain the warranty coverage. Currently, AEY runs two generator sets concurrently to meet these specifications. A unit approaching twice the size of the current largest unit (Unit 4) would make operating efficiency much more difficult to maximize.

**Recommendation**

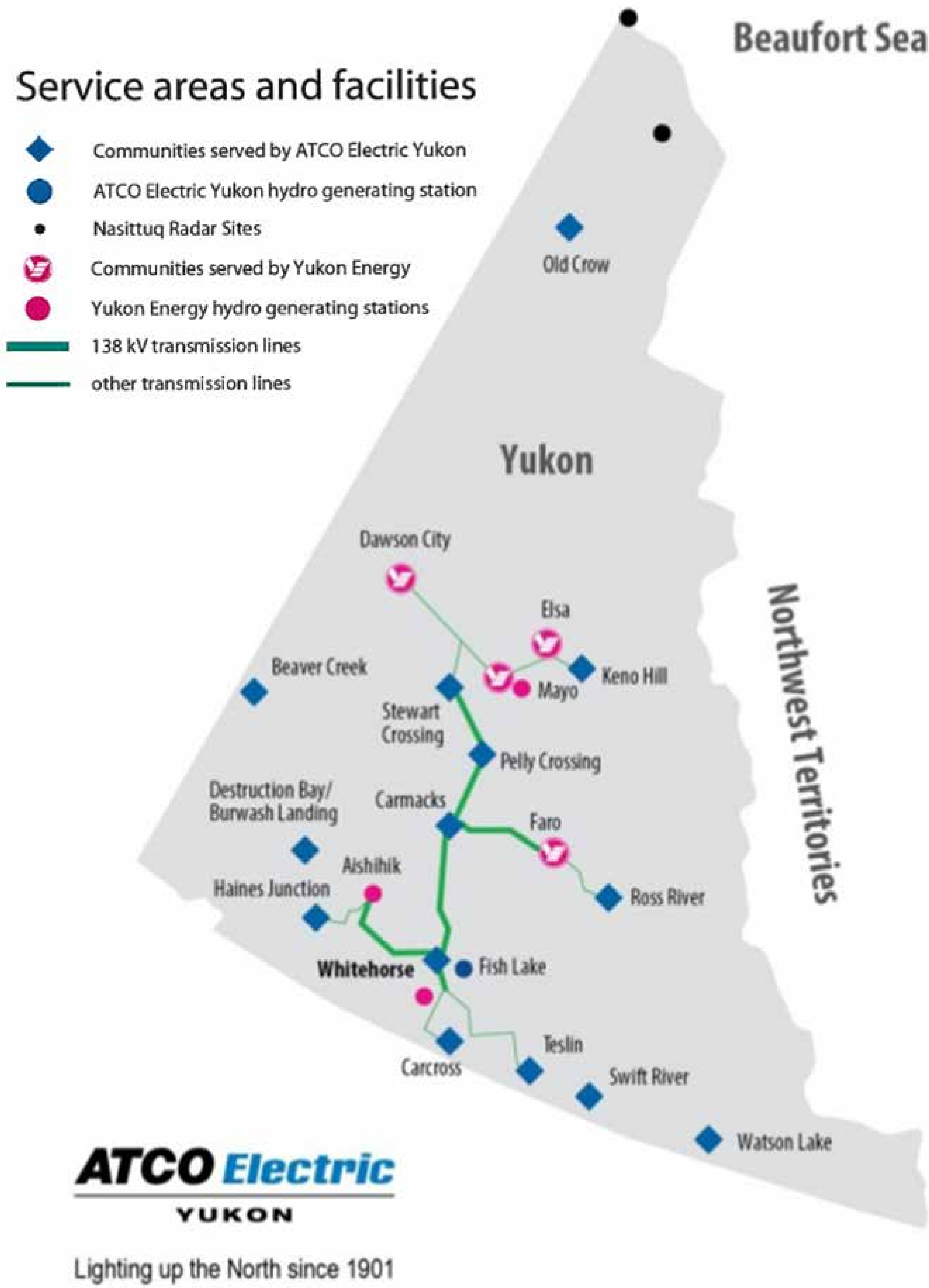
19. AEY recommends Alternative 2 – Replace Units 1, 3, and 6. Delivering power safely and reliably is AEY's primary driver. To meet the power needs of the community, AEY needs to upgrade its generating capacity at the Watson Lake Generating Facility to ensure its Firm Capacity meets the Peak Load. Replacing these generators with larger units will provide this necessary increase in Firm Capacity.

20. In addition, AEY must ensure that its equipment is prudently upgraded before it becomes an operational liability. This is an opportune time to upgrade these aging generators prior to major maintenance and the expected decrease in operational efficiency.

**Appendices**

Appendix A Service Areas and Facilities of ATCO Electric Yukon

## Appendix A: Service Areas and Facilities of ATCO Electric Yukon



ATCO Electric

YUKON

# 2023-2024 General Rate Application (GRA)

Watson Lake Unit 4 – Installation of Remote Electronic Modular Control Panel

2018-2022 Business Case #08

## Executive Summary

1. The engine control components on Unit 4 at the Watson Lake Generating Facility have had repeated failures and therefore reduced equipment availability and reliability. The control components, terminals, contacts, and wires are mounted to the engine and are therefore subject to constant vibration. AEY will relocate these components off the engine to a standalone Electronic Modular Control Panel (EMCP) or into the existing breaker control cabinet. This move will increase the reliability of the generating unit and extend the life of the electrical components. In addition, the new control panel and components will be more consistent with how generating units 1, 3, and 6 are controlled, improving inter-changeability and operational consistency.

## Background

2. The Watson Lake Generating Facility is currently the only source of power for the communities of Watson Lake (YK), Upper Liard (YK), and Lower Post (BC). AEY provides service to approximately 740 Residential and 206 Commercial Customers in those communities. The generating facility houses 6 diesel generators.

3. Generating unit 4 was manufactured in 2013 and is approaching 30,000 operating hours (2021). The electrical equipment mounted to the unit is regularly failing thereby requiring unplanned and reoccurring maintenance and repair. Time is spent troubleshooting faults and unplanned equipment trips. Other engines in AEY's fleet with independently mounted controls do not see the same frequency of failure and downtime for control components.

## Project Description

4. Work with a manufacturer to design an appropriate EMCP cabinet and harness. Purchase standalone EMCP cabinet and relocate existing, salvageable electrical components. Relocate the unit's voltage regulator to breaker control cabinet and all other terminals and devices to the new EMCP cabinet.

5. AEY will conduct the engineering and create new electrical drawings with installation work completed by an electrical contractor. Final commissioning of the EMCP

completed by AEY, electrical contractor, and Finning (engine manufacturer representative).

**Project Schedule and Cost**

6. The project went into service Q3 2021 and cost $151,000.

**Business Drivers and Benefits**

7. The benefits of stand-alone cabinet compared to mounting on-engine will be increased reliability of the engine as its electrical system would be less likely to fail from vibration. A secondary benefit would be standardization of electrical control equipment, as this EMCP and control unit would be similar to new control units installed during the replacement of Units 1, 3 and 6.

**Evaluation of Viable Alternatives**

<u>Alternative 1 – Status Quo – Replace Failing Equipment with on Engine Components.</u>

8. Replace all failing equipment on generating unit 4 including the terminals, contacts, and wiring on engine. This would increase the reliability of the unit in the short-term but would not prevent unplanned long-term failure as the components will remain exposed to engine vibration. Terminal and wiring replacement would require resources onsite and the unit offline/unavailable for minimum five (5) days and cost approximately $50,000. As the equipment began exhibiting their current issues at 30,000 operational hours and AEY replaces high RPM generators at approximately 100,000 operational hours, similar replacement projects would likely occur one-two more times during the engine's lifetime. The unpredictable nature of these failures means that the grid outages are possible due to trips or a lack of firm capacity.

<u>Alternative 2 – Install a New Remote Electronic Modular Control Panel</u>

9. This alternative would install a new remote EMCP, remove all electrical components mounted on generating unit 4, and re-install any necessary remaining components in the new control panel including replacing any equipment that has failed. This alternative addresses the current operating issues with the generator

**Recommendation**

10. AEY recommends Alternative 2, installing a new remote EMCP and reinstalling and/or replacing the existing engine-mounted equipment with this new control panel. These alternative resolves both the short-term issue of the failing equipment as well as the potential long-term issue of needing to replace this equipment again in the future.

ATCO Electric
YUKON

# 2023-2024 General Rate Application (GRA)

Upgrade Regulators at Laberge Substation

2018-2022 Business Case #09

## Executive Summary

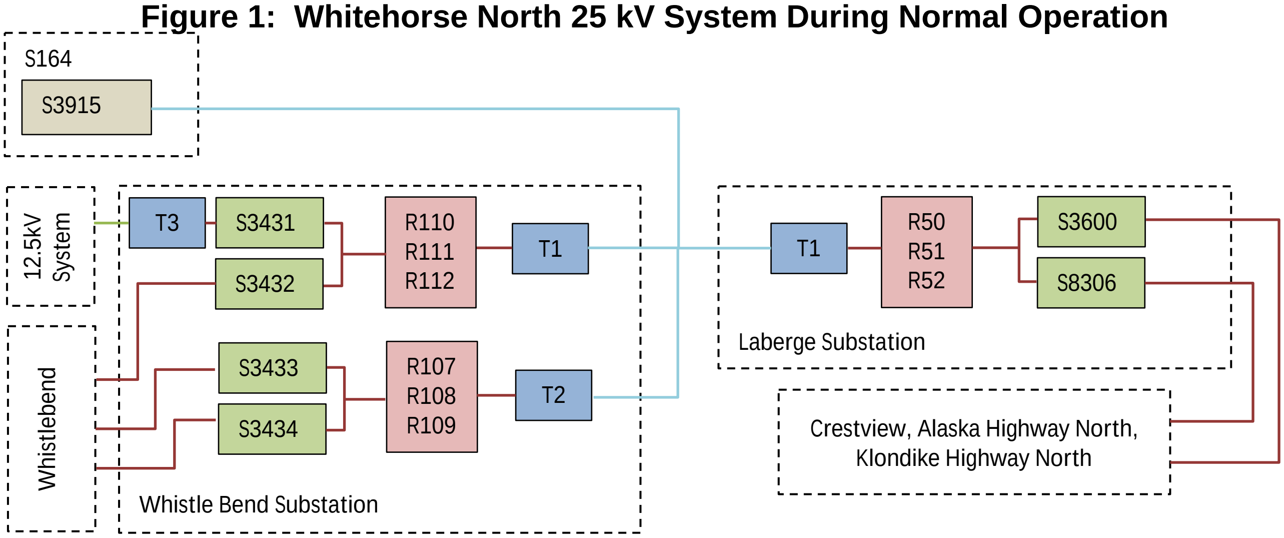
1. Significant load growth is expected on the Whitehorse North 25 kV System over the next six-years. At present, there is a contingency scenario that cannot be adequately addressed. As the load grows, substation regulator capacities will be exceeded, rural customer voltages will drop below acceptable levels and the number of failed contingency scenarios will increase. The projected load growth must be planned for, and accommodations implemented to ensure continued safe and reliable operation of the Whitehorse power system.

## Background

### System Configuration

2. During normal operation, the North 25 kV System is supplied power from a single transmission substation source (S164), through two sub-transmission substations (Laberge Substation and Whistle Bend Substation), and out to both urban and rural customers in the northern Whitehorse area and along the North Klondike and Alaska highways. At each voltage level, there are interconnection points between parallel feeds, allowing for a variety of potential system configurations.

**Figure 1: Whitehorse North 25 kV System During Normal Operation**



**Legend**

| | | | |
|---|---|---|---|
| 34.5kV Breakers | 25kV Reclosers | 34.5kV Lines | 25kV Lines |
| Transformers | Regulators | 12.5kV Lines | |

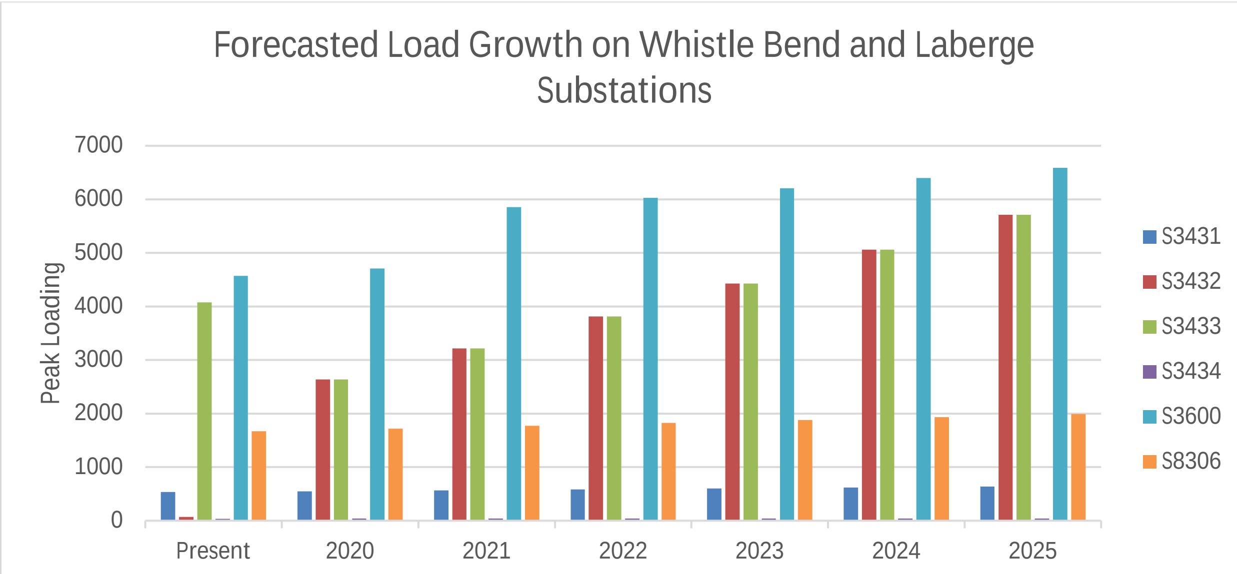
Historical Load Growth

3. Between 2016 and 2018, the total peak loads measured at the transmission substations in the Whitehorse area (S150, S164, S170) increased at an average of 2.99 percent per year. Therefore, unless they are associated with known projects/load additions, the average load growth across the system will be assumed at three percent per year. A six-year planning period was selected as Whistle Bend subdivision is expected to grow at a rate of 1 MW/year as Stages 4 to 7 are constructed and commissioned leading up to the end of 2025. Additionally, a load addition of at least 1 MW is planned along Takhini Hot Springs Road as part of an upcoming expansion at the hot spring's facility in 2021.

Forecast Load Growth

4. Currently the Whistle Bend Subdivision is undergoing extensive construction and is expected to complete Stage 7 by the end of 2025. This growth will dramatically increase the loading on the Whistle Bend Substation: therefore, the loading on Whistle Bend's feeders has been forecast independent of the three percent per year calculated for the rest of the city. The Whistle Bend Subdivision loading for the planning period was developed based on peak Stage 1-3 loading, forecast customer count and the estimated construction schedule up to the end of Stage 7. The complete forecast for each of the feeders in Laberge and Whistle Bend is shown in Figure 2 below.

**Figure 1: Forecast Load Growth for Whistle Bend and Laberge Substations until the Completion of Whistle Bend Stage 7**




* Load growth for Whistle Bend Subdivision is forecast to be redistributed evenly over reclosers S3432 and S3433 in future years, instead of only loading S3433 as is the present arrangement.
** The 1 MW addition to S3600 in year 2020-2021 is due to a planned load addition at Takhini Hot Springs.

## Project Description

5. Upgrades to the Laberge substation regulators will be completed so that future load growth does not overload the existing regulators. Due to the timing uncertainty of building a new 25 kV substation as a result of long lead times and land procurement upgrades are the best available solution.

## Project Schedule and Cost

**Table 1: Project Schedule and Cost ($000)**

| | Cost | In-Service Date |
|---|---|---|
| Install 400A regulators at Laberge substation | 129 | 2020 |

## Business Drivers and Benefits

6. Currently, no system components are overloaded, but the Laberge Substation Regulators are expected to overload in the next six-years (shown in the red cell in Table

2, below). Below are modelled forecasts for system loading for the six-year planning period.

### Table 2: Whitehorse North 25 kV System Peak Loading

| | Equipment / System Area | Critical Ratings | Present Status (2019) | Future Status (2025) |
|---|---|---|---|---|
| Whistle Bend Substation | Transformer T1 | 34.5/25 kV 10MVA | 6% Loaded | 63% Loaded* |
| | Transformer T2 | 34.5/25 kV 10MVA | 41% Loaded | 58% Loaded* |
| | Transformer T3 | 25/12.5 kV 5MVA | 12% Loaded | 13% Loaded |
| | Reclosers: S3431, S3432, S3433, S3434 | 27 kV 630A each | 2%, 0%, 15%, 0% Loaded | 2%, 21%, 21%, 0% Loaded* |
| | Regulators: R110, R111, R112 | 400A each | 4%, 4%, 4% Loaded | 38%, 37%, 36% Loaded |
| | Regulators: R107, R108, R109 | 400A each | 24%, 24%, 24% Loaded | 33%, 34%, 33% Loaded |
| Laberge Substation | Transformer T1 | 34.5/25 kV 10MVA | 62% Loaded | 86% Loaded |
| | Reclosers: S3600, S8306 | 38 kV 630A, 400A (per phase) | 17%, 10% Loaded | 24%, 12% Loaded |
| | Regulators: R50, R51, R52 | 200A each | 62%, 78%, 77% Loaded | 86%, 107%, 106% |
| S164 | Transformer T1 | 138/34.5 kV 25MVA** | 43% Loaded | 72% Loaded |

* Future 25 kV load on Whistle Bend Substation redistributed evenly across S3432, S3433.

** Assuming that S164 is operating in OFAF mode. If Transformer T1 is unable to operate at the nameplate rating of 25 MVA, the transformer will require upgrades and/or replacement in coming years. This asset is owned by YEC, therefore any upgrades required are outside of the scope of this study.

Note: Additional substation apparatus (Gang Switches, Buses, etc.) were not included in Table 1 as their rating greatly exceeds that of the other equipment and will not be the limiting factor for substation capacity.

**Evaluation of Viable Alternatives**

7. The main issues facing the North 25 kV System over the upcoming 6 year period are:

- Capacity: Overload on Regulators (R50, R51, R52) at Laberge Substation;
- Contingency Scenario 1: Loss of a single 34.5/25 kV transformer; and
- Contingency Scenario 2: Loss of the 34.5 kV primary bus at Whistle Bend Substation.

8. To address these issues, the following potential solutions have been considered:

(1) New 25 kV Substation & System Reconfiguration;
(2) Laberge Substation Upgrades; and
(3) Status Quo.

<u>Alternative 1: New 25 kV Substation & System Reconfiguration</u>

9. Building a new substation for the 25 kV North System would directly resolve Contingency Scenarios 1 and 2, by providing additional reserve capacity to assist with system reconfiguration during outages. In 2025, the total peak loading on S164 is estimated to be 20.7 MVA. In Contingency Scenario 2, the only remaining transformer is T1 at Laberge, with a rating of 10 MVA. This results in 10.7 MVA of power that needs to be alternatively sourced by a new substation. At minimum the new substation should be designed to continuously provide at least 10.7 MVA without overloading any equipment.

10. To address the capacity issue with the regulators at Laberge Substation, during normal operation it is recommended that the load currently serviced by Laberge T1 is split among Laberge and the new substation. The simplest and most cost-effective method of dividing the load is to service Crestview area by the existing Laberge Substation and service Alaska Highway North and the Klondike Highway by the new substation. This is not an equal division of load (only ~25 percent of estimated Laberge load is in Crestview area); however, it does shorten the average distance between a substation and load-centers, without requiring any additional distribution line to be constructed. This will contribute to minimizing line losses and lessen the voltage drop

between the substations and end-of-line customers. The recommended method to achieve this would be to create a dedicated feeder at the new substation to feed the existing 5L645 (servicing Alaska Highway North and Klondike Highway North). This would effectively allocate all of Laberge's capacity to the Crestview area during normal operation. Additionally, with the majority of the future load growth expected in the Whistle Bend area, it is recommended that the new substation also includes a dedicated feeder that connects to the north-west region of Whistle Bend.

11. This option covers Contingency Scenario 1 and 2 and resolves the forecast Laberge regulator capacity issue.

Alternative 2: Laberge Substation Upgrades

12. As noted in Option 1, to cover all contingency scenarios that are forecast for 2025, at least 10.7 MVA of additional transformer capacity is required on the North 25 kV system. This option meets this requirement by adding an additional transformer to the Laberge substation that is rated for at least 10.7 MVA. The additional transformer capacity would cover both identified contingency scenarios and during normal operation, this transformer would be a dedicated feed for line 5L645 (servicing Alaska Highway North and Klondike Highway North), along with the ability to tie in to 5L648 and support future expansions of Whistle Bend along the northwest side of the subdivision. By alleviating the strain on the existing Transformer T1 at Laberge Substation, the capacity issue on the existing regulators R50, R51 and R52 will be resolved.

13. This option covers Contingency Scenario 1 and 2 and resolves the forecast Laberge regulator capacity issue.

Alternative 3: Status Quo

14. Without making any changes to the North 25 kV system and with load growth continuing at the expected rates, equipment will be overloaded soon. Assuming that peak loading only occurs in winter months (with temperatures at or below 0˚C), power transformers can be steadily overloaded at 1.22 p.u. of their nameplate rating and can

be emergency overloaded up to 1.31 p.u. for less than eight hours before the loading must drop below 0.90 p.u.

15. Utilizing these seasonal equipment ratings and assuming that the Laberge regulators are upgraded to no longer be the limiting factor at that substation, the North 25 kV System will be able to handle Contingency Scenario 2 up until 2021. In 2021, the peak loading on the North 25 kV System is anticipated to be ~14.7 MVA. This load cannot be carried by Laberge T1 alone.

16. Additionally, any time equipment operates outside of nameplate rating, there is the potential for decreased lifespan and increased maintenance requirements on these assets. Deferring system improvements may result in increased service and asset replacement costs going forward.

17. This option covers Contingency Scenario 1 in its entirety and covers Contingency Scenario 2 up until 2021. This does not address the forecast Laberge regulator capacity issue.

Alternative 4: Regulator Upgrades

18. Upgrade the three regulators from 200A to 400A. This is similar to Alternative 3 but it provides relief for the most pressing potential overloading of the system. This allows Alternative 1 more time to be fully designed and approved.

**Recommendation**

19. Alternative 1 is the recommended solution; however, with uncertainty on when a new 25 kV substation can be built given lead times and land procurement, Alternative 3 status quo will be utilized for the intermediate time for the overall project. In the interim, as the regulators are anticipated to exceed maximum load before the full project is designed and approved, this recommendation is Alternative 4 for upgrading the regulators at Laberge substation to eliminate an overload condition during normal operation.

ATCO Electric

YUKON

# 2023-2024 General Rate Application (GRA)

Service Complex Boiler Replacement

2018-2022 Business Case #10

**Executive Summary**

1. The AEY Service Complex requires replacement boilers. The current heating infrastructure at the Complex is a two-boiler system, with both boilers in need of repairs.

2. The project will include an engineered design and contracted installation for new hydronic heating system with consideration for ease of maintenance and operating efficiency.

**Background**

3. The AEY Service Complex, including its current heating infrastructure, was designed and built in 1991. The heating system is a two-boiler system, installed in 2003, that shows signs of fatigue and potential failure. One of the boilers is leaking and the second boiler has had a relay fail. The current model is obsolete and due to its size (500 MBtu/h x2), requires a ticketed gasfitter to perform work on the burner. As there are very few ticketed gasfitters in the Yukon, this can complicate maintenance and replacement timing. In the winter of 2020, the sole operational boiler, the one with the failed relay, did not meet the demand for the building and the building did not have adequate heat for building occupants. This project will assess the required demand of the building and install modernized equipment to ensure adequate heat.

**Project Description**

4. Working with a vendor to design and install a new hydronic heating system for the Service Complex. This option was selected as it uses the existing infrastructure of the building and therefore does not incur additional expense modifying the infrastructure that other options would require. The existing boiler system will be removed, and new control system will be tied into the existing infrastructure. The new heating system will have a final heating output of 897 MBtu / h which is adequate to meet the building’s demand.

**Project Schedule and Cost**

5. The project cost $107,443, including a Yukon Government “Good Energy Commercial Program” rebate of $31,736. AEY qualified due to the greenhouse gas

emissions reduction the higher efficiency boilers provided. This project was constructed over eight weeks in 2020.

**Evaluation of Viable Alternatives**

6. When it was determined that the boiler system needed to be replaced, several alternatives were explored. Many of these alternatives required altering the infrastructure of the building, which added expense to the point where they were no longer considered viable. The solution chosen used the existing infrastructure, increased the heating output to provide the redundancy lacking in the previous system, and reduced the greenhouse gas emissions.

**Recommendation**

7. Install new hydronic heating system for the Service Complex.

ATCO Electric

YUKON

# 2023-2024 General Rate Application (GRA)

McIntyre Subdivision Contingency Loop

2018-2022 Business Case #11

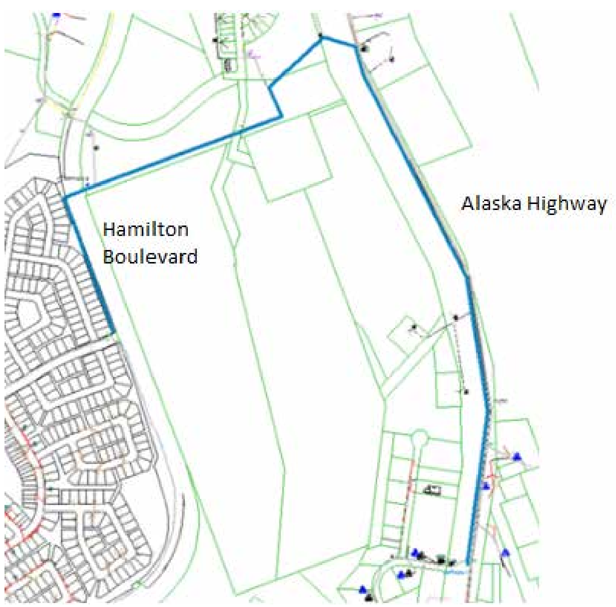
## Executive Summary

1. AEY has a duty to provide safe and reliable electricity service. Its goal is to restore all critical loads including residential and commercial customers as quickly as possible for any unplanned outage. Repairs should be achievable through minimal switching steps to reduce risk to customers, AEY employees, and the electrical system.

2. There are approximately 200 customers in the McIntyre Subdivision of Whitehorse. The McIntyre Subdivision is a radial network with looping available within the subdivision. However, the subdivision itself is single sourced creating a security of supply risk for these customers. If an emergency or extensive operational repair is required, the outage time could be extensive.

3. To address the supply risk, AEY recommends expanding the existing 25 kV infrastructure northward along the Alaska Highway through Valleyview providing an alternate feed to the neighbourhood. New underground cable would connect this infrastructure to the north end of McIntyre Drive along Hamilton Boulevard.

**Figure 1: Location of the Proposed 25 kV Expansion**




4. This recommendation would reduce the restoration time of the McIntyre Subdivision in emergency circumstances and prevents downtime during maintenance of

the current feed. Additionally, as AEY intends to convert the majority of the Whitehorse Distribution infrastructure to 25 kV, this expansion into the McIntyre Subdivision aligns with the long-term plan for the city.

**Background**

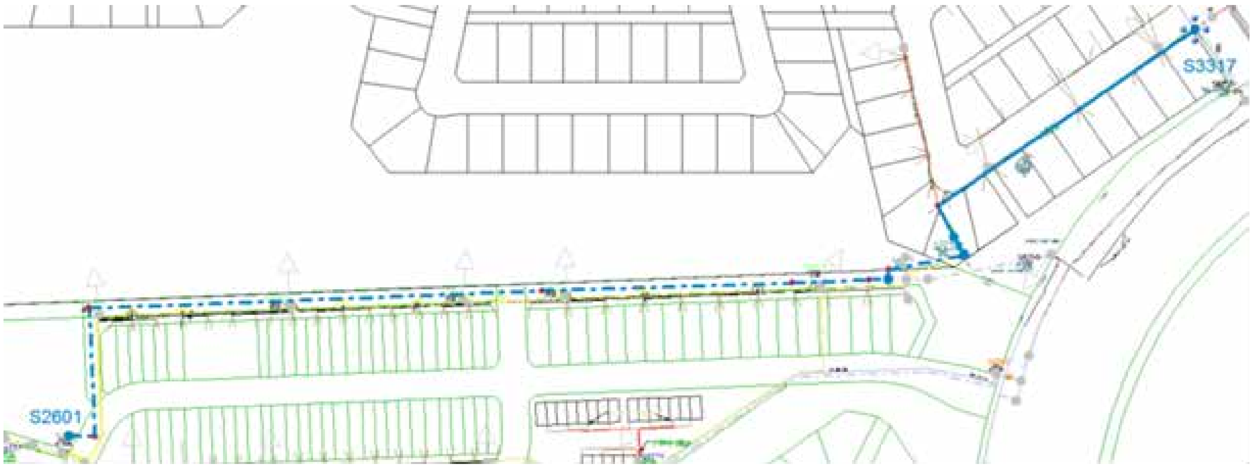
5. There are approximately 200 customers in McIntyre Subdivision in Whitehorse on the West side of the Alaska Highway.

**Figure 2: McIntyre Subdivision**


6. The Subdivision is in a radial configuration fed via underground cable. This newly installed branch runs behind Mallard Way for approximately 600 meters and along McCandless Crescent to McIntyre Drive for approximately 220 meters. The branch includes underground cables, fuses, poles, overhead conductors, and switch cubes. In the event of equipment failure or a fault between switch cube S2601 and fuse S3317

(location shown below in Figure 3), there is no option to restore power before emergency repairs are made.

**Figure 3: Location of S2601 to S3317 Branch, South of McIntyre Subdivision**




7. Emergency repairs could take anywhere between 1-12 hours to complete, depending on the affected equipment.

**Table 1: Emergency Repair Matrix and Risk**

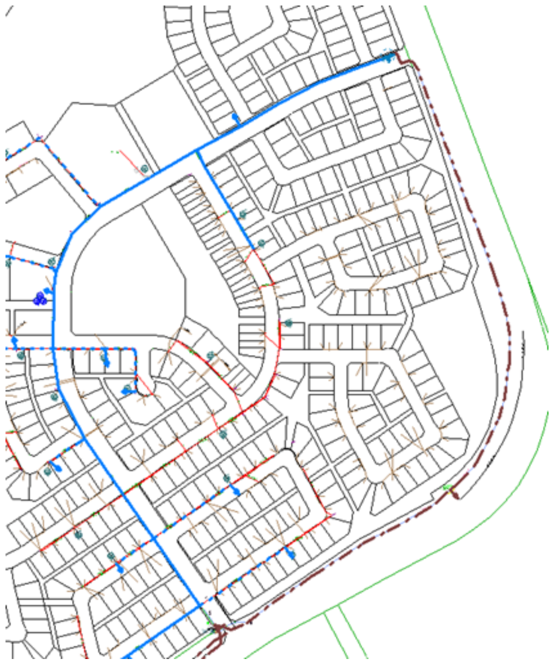
| Equipment Type | Quantity | Estimated Repair Time | Relative Risk |
|---|---|---|---|
| Switch Cube | 2 (S4741, S2601) | 2-3 hours | Medium (third party impact) |
| Underground Cables | 2 sets of three | 3-4 hours per cable | Low (digging contact) |
| Fuses | 1 set of three (S3710) | 1 hour | High (overload, third party impact) |
| Overhead Conductor/Poles | Approximately 8 poles | 3-4 hours | High (third party contact, tree/wildlife) |

8. Emergency repairs are often used as a contingency plan for single transformers connected to radial underground systems or multiple transformers on radial overhead. All new urban neighborhood underground construction is designed with loops in the network.

9. The previous 35 kV underground network in McIntyre had two potential feeds, one from S150, and a second from S17. If the primary feed failed, the backup feed

would power the subdivision quickly by closing a normally open switch. This reduced the urgency of an emergency repair for load pickup to McIntyre.

**Figure 4: Old 35 kV Looped Configuration**



10. There have been two unplanned outages in the past three years along this span, both due to vehicles colliding with the pole or guy wires located between Mallard Way and McCandless Crescent. Each outage lasted approximately four hours. These are the most severe outages that have affected this specific branch within the past 10 years.

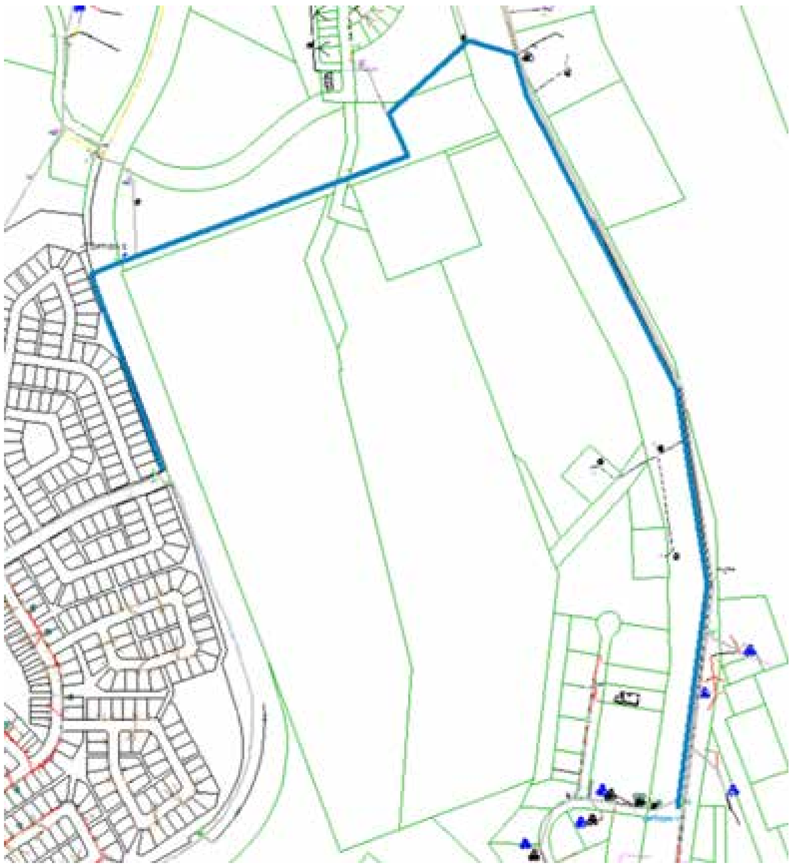
11. Though the security of supply issue does not require immediate action as outage times have been limited to less than 12 hours, a solution that can be installed within two years has been recommended.

**Project Description**

12. The most accessible line for 25 kV bus is in Hillcrest at the intersection of Alaska Highway and Burns Road. To tie into this line and extend the 25 kV system, replace the existing 12.5 kV infrastructure headed north along Alaska Highway with 25 kV infrastructure and then double circuit along the existing 12.5 kV line headed west behind Valleyview. Cross the Alaska Highway and install new underground line under Hamilton

Boulevard and to the north end of McIntyre Drive, tying into the 25 kV overhead. The proposed alignment is shown below in Figure 5.

**Figure 5: Hillcrest Double Circuit Routing**



**Project Schedule and Cost**

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

| | Actuals | Completion Date |
|---|---|---|
| Double Circuit | 295 | 2019 |

**Business Drivers and Benefits**

Security of Supply

13. AEY has a duty to provide safe and reliable electricity service. In an emergency scenario, the current system configuration for the McIntyre subdivision will result in an

extended outage 1-12 hours. This project will provide looped supply, greatly reducing the estimated outage timing and allowing backup service to be provided by closing a switch.

<u>Alignment with Future System Plan</u>

14. AEY has a long-term plan to upgrade the Whitehorse distribution infrastructure to 25 kV. By expanding the 25 kV system to the McIntyre Subdivision, AEY meets the intent of this plan and allows for ease of future growth of the 25 kV system.

**Evaluation of Viable Alternatives**

<u>Alternative 1 – Status Quo – Do Nothing</u>

15. This alternative proposes to change nothing on the system. While the system is operating safely, there is a risk to the security of supply in emergency situations. If the existing system requires an operational repair or is damaged by a third party, there will be an outage to the subdivision that requires between 1-12 hours to repair. This security of supply issue, combined with AEY's intent to upgrade the Whitehorse distribution system to 25 kV, means that this alternative is not recommended.

<u>Alternative 2 – Double Circuit from Hillcrest Drive</u>

16. Replace the existing 12.5 kV infrastructure headed north along Alaska Highway with 25 kV infrastructure extending from the most accessible line in Hillcrest Drive at the intersection of Alaska Highway and Burns Road. Then double circuit along the existing 12.5 kV infrastructure headed west behind Valleyview. A separate road crossing over the Alaska Highway would likely be required. New underground would be installed under Hamilton Drive and to the north end of McIntyre Drive, tying into the 25 kV overhead. This route is outlined in Figure 5.

17. This would provide a second feed for McIntyre Subdivision at the north end of McIntyre Drive. In the event of a failure at any point where S3317 fuses to McIntyre Substation, the second feed could be switched in to supply McIntyre subdivision from Arkell Substation. This would also create another path for S150 to pick up McIntyre and other subdivisions in the event of a high-level failure at S17.

18. By expanding 25 kV infrastructure along the Alaska Highway, future conversion projects (e.g., Valleyview or Takhini) can utilize this branch. This addition of infrastructure allows the eventual conversion to 25 kV to occur across several smaller extensions as opposed to a single large-scale installation of 25 kV infrastructure.

19. The cost of this option is preliminarily estimated at $410,000. This assumes that all poles along the double circuit path will need to be replaced.

Alternative 3 - Underground/Overhead Tie to Hillcrest

20. A tie could be made from Hillcrest Drive (S9424) to the southern end of McIntyre Drive. Overhead lines would be used until Hamilton Boulevard after which underground cables would be installed to cross Hamilton Boulevard and tie into a new switch cube on McIntyre Drive.

**Figure 6: Hillcrest New Tie-line**


21. This option provides a true alternate feed (from S150) to the McIntyre Subdivision. However, since the alternate feed would connect through the same switch cube as the primary feed, a single point of failure for the subdivision would remain at this switch cube.

22. This tie to Hillcrest Drive does not lend itself to future 25 kV expansion as the majority of the Hillcrest area has already been converted to 25 kV, and there is little requirement for expansion in the area.

23. The cost of this option is preliminarily estimated at $280,000.

**Recommendation**

24. AEY recommends Alternative 2, installing a double circuit from Hillcrest Drive. This alternative is recommended as it provides additional security of supply to the McIntyre Subdivision while also expanding the 25 kV infrastructure that will be utilized throughout Whitehorse.

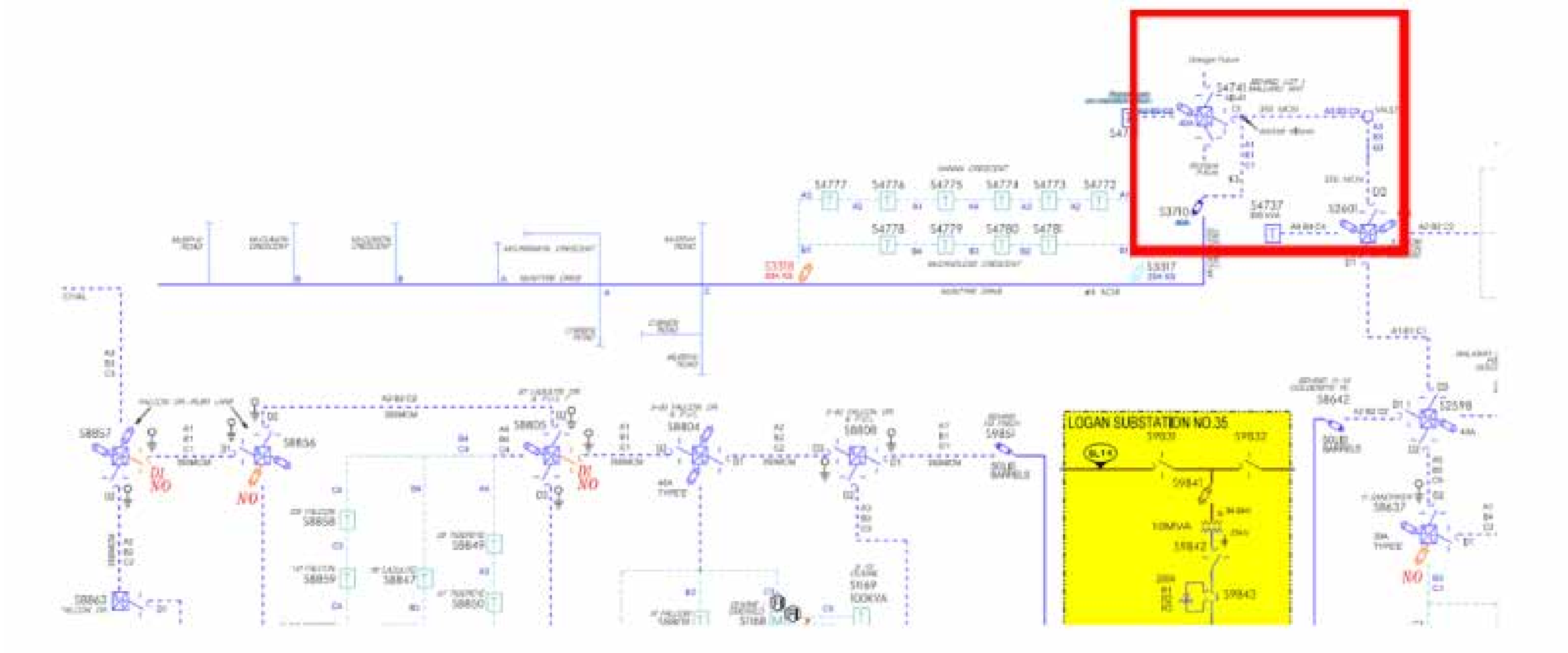
25. McIntyre Subdivision will also be provided with a proper backup feed in the event of a high-level fault at S150. All customers within the subdivision will be affected as there is no sectionalizing in place along that line.

26. The 25 kV infrastructure will be expanded up the Alaska Highway to Valleyview, tying into a new underground cable that connects to overhead at the north end of McIntyre Drive. This will provide a tie in point for future projects as AEY expands its 25 kV network in Whitehorse. The other alternatives do not offer any significant opportunity for 25 kV infrastructure growth and alternative #3 has a single point of failure in the design.

**Appendices**

Appendix A Single Line Diagram of the McIntyre Subdivision

## Appendix A: Single Line Diagram of the McIntyre Subdivision



ATCO Electric

YUKON

# 2023-2024 General Rate Application (GRA)

Annual Right-of-Way (ROW) Widening

2018-2022 Business Case #12

## Executive Summary

1. The purpose of capital brushing is to ensure that AEY provides its customers with a safe, reliable power system that complies with legal and regulatory requirements.

2. AEY has an ongoing capital brushing plan. This plan capitalizes brushing work conducted in the following circumstances:

- Brushing at time of construction;
- Powerline widening along right of ways for trees not previously cleared at time of construction; and
- Hazard tree removal – trees either on an existing right of way which has not been previously cleared or tress outside the existing ROW.

## Background

3. Between 2018 and 2022, AEY carried out brushing work on various areas of the power system. These areas included:

- South Klondike Highway;
- North Klondike Highway;
- Alaska Highway;
- Whitehorse;
- Stewart Crossing;
- Keno;
- Minto;
- Teslin;
- Watson Lake;
- Carmacks;
- Pelly Crossing;
- Ross River;
- Marsh Lake; and
- Haines Junction.

## Project Description

4. Brushing work is conducted by AEY employees or certified brushing contractors. This work is completed by the following methods:

- Mowing;
- Slashing; and
- Pruning.

5. Currently, AEY does not use any herbicide applications.

6. AEY has been following a five-year cycle based on assessments made by our brushing coordinator and vegetation management consultant. Selected areas consider power outage data, environmental impacts, concerns from the public and traditional Indigenous territories.

**Project Schedule and Cost**

7. Refer to Appendices A – E.

**Business Drivers and Benefits**

8. A well managed capital brushing plan greatly improves the reliability of the power system. Outages are reduced and safety to the public is maintained. Fire hazards are also less likely with powerline right of ways that are brushed to a standard and extent sufficient to maintain safe operations.

**Evaluation of Viable Alternatives**

9. Overhead power lines make up much of the AEY power system. Brushing will be required. There are no suitable alternatives.

**Recommendation**

10. Continue will the five-year capital brushing plan.

## Appendices

| | |
|---|---|
| Appendix A | 2018 Capital Brushing |
| Appendix B | 2019 Capital Brushing |
| Appendix C | 2020 Capital Brushing |
| Appendix D | 2021 Capital Brushing |
| Appendix E | 2022 Capital Brushing |

## Appendix A: 2018 Capital Brushing

| Year | Project | Area | Cost ($) |
|---|---|---|---|
| 2018 | Y14484 | Whitehorse | 117,997 |
| 2018 | Y14485 | Alaska Hwy South | 9,338 |
| 2018 | Y14487 | Teslin | 38,465 |
| 2018 | Y14489 | Stewart Crossing | 17,417 |
| 2018 | Y14492 | Marsh Lake | 25,327 |
| 2018 | Y14606 | Watson Lake | 22,138 |
| 2018 | Y14607 | Haines Junction | 28,071 |
| 2018 | Y14486 | South Klondike Hwy | 28,865 |
| 2018 | Other | Projects under $5,000 | 4,304 |
| | | | **291,922** |

## Appendix B: 2019 Capital Brushing

| Year | Project | Area | Cost ($) |
|---|---|---|---|
| 2019 | 1008579 | City of Whitehorse | 281,823 |
| 2019 | 1008581 | Tagish | 27,804 |
| 2019 | 1008583 | Stewart Crossing | 49,979 |
| 2019 | 1011410 | Mary Lake | 27,850 |
| 2019 | 1011411 | MacPherson | 17,807 |
| 2019 | 1020572 | Riverdale | 13,511 |
| 2019 | 1020575 | Marsh Lake | 8,736 |
| 2019 | 1018805 | Grey Mountain rd | 24,837 |
| 2019 | 1032124 | Various | 36,877 |
| | | | **489,224** |

## Appendix C: 2020 Capital Brushing

| Year | Project | Area | Cost ($) |
|---|---|---|---|
| 2020 | 1034971 | Whitehorse- Porter Creek / Riverdale | 357,846 |
| 2020 | 1034972 | Carcross | 54,044 |
| 2020 | 1034975 | Watson Lake | 22,099 |
| | | | **433,989** |

## Appendix D: 2021 Capital Brushing

| Year | Project | Area | Cost ($) |
|---|---|---|---|
| 2021 | 1048730 | Whitehorse | 336,637 |
| 2021 | 1048732 | Watson Lake | 33,897 |
| 2021 | 1052850 | Golden Horn | 82,748 |
| 2021 | 1048730 | Burwash | 27,701 |
| | | | **480,983** |

## Appendix E: 2022 Capital Brushing

| Year | Project | Area | Cost ($) |
|---|---|---|---|
| 2022 | 1071147 | Golden Horn | 78,299 |
| 2022 | 1071150 | Riverdale | 63,993 |
| 2022 | 1071151 | Carmacks | 138,591 |
| 2022 | 1071152 | Teslin | 63,575 |
| 2022 | 1071153 | Carcross / Tagish | 63,829 |
| 2022 | 1071154 | North Klondike Hwy | 95,835 |
| 2022 | 1071155 | Haeckel Hill | 51,068 |
| | | | **555,190** |

ATCO Electric

YUKON

# 2023-2024 General Rate Application (GRA)

Fleet Replacement

2018-2022 Business Case #13

## Executive Summary

1. AEY currently operates and maintains 76 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. Between 2018 and 2022, four (4) service vehicles (over $100,000) were identified for replacement and two additional vehicles were purchased as fleet additions:

- Addition YT144 was purchased for use by a new mechanic position.
- Addition YT151 was purchased for use in Old Crow, this was a new addition to the community of Old Crow.

## Project Description

3. Procurement of these six vehicles through ATCO Fleet and 3rd party vendors.

## Project Schedule and Cost

**Table 1: Fleet Replaced**

| Unit | Description | Year Purchased | Kilometers |
|---|---|---|---|
| YT091 | Technologist Truck | 2010 | 245,537 |
| YT092 | Crew Flat Deck | 2008 | 237,000 |
| YT886 | Technologist Truck | 2009 | 248,748 |
| YT429 | Bucket Truck | 1994 | 81,471 |

**Table 2: Purchased Fleet**
**($000)**

| Unit | Description | Year Purchased | Purchase Cost |
|---|---|---|---|
| YT144 | Mechanic Truck | 2019 | 145 |
| YT145 | Technologist Truck | 2019 | 149 |
| YT148 | Crew Flat Deck | 2020 | 129 |
| YT151 (Fleet addition) | Digger Derrick – Old Crow | 2021 | 335 |
| YT159 | Technologist Truck | 2021 | 158 |
| YT169 | Bucket Truck – Watson Lake | 2022 | 264 |

## Business Drivers and Benefits

4. The typical lifecycle of an AEY fleet vehicle is evaluated after seven years of service or 200,000 kilometers. All the vehicles in the above table exceeded this criterion and required replacement, aside from the two additions. Replacement of these vehicles improves the reliability and reduces maintenance costs.

## Evaluation of Viable Alternatives

5. Extending the life cycle period for fleet vehicles is considered; however, this option leads to a reduction of reliability and an increase in maintenance costs.

## Recommendation

6. Replacement of fleet with new vehicles and add YT144 and YT151.

ATCO Electric
YUKON

# 2023-2024 General Rate Application (GRA)

Satellite Radios

2018-2022 Business Case #14

## Executive Summary

1. AEY fleet vehicles are equipped with Very High Frequency (VHF) radios for communications. Over the years this form of communication has become less reliable due to the aging infrastructure that is in place in remote locations around the Yukon. AEY needed a new reliable form of communication for daily operations.

## Background

2. In recent years the VHF radio system channels have proven unreliable for important communication activities, such as power system switching. This switching involves clear and concise communications with the Operator in Charge (OIC) for proper procedure and employee safety.

## Project Description

3. AEY has purchased and installed 38 satellite radios for use in 37 vehicles and one base station for system dispatch.

## Project Schedule and Cost

**Table 1: Project Schedule and Cost ($000)**

| Year | Cost |
|---|---|
| 2022 | 157 |

## Business Drivers and Benefits

- Satellite radios do not require towers to operate.
- There is no ongoing maintenance required at remote locations.
- Talk group is 750,000 km2. Far greater range than the VHF system in place.
- Satellite radios are portable and can be removed from the dock.
- Satellite radios can also be used as a satellite phones, allowing for second form of communication.

**Evaluation of Viable Alternatives**

4. Alternative 1: Continue to use and maintain VHF system. This would be costly and provide a less reliable form of communication.

**Recommendation**

5. Replacement of VHF with satellite radios.

ATCO Electric
YUKON

# 2023-2024 General Rate Application (GRA)

Line Moves in Highway ROW

2018-2022 Business Case #15

## Executive Summary

1. AEY often has powerlines in the highway Right-of-Way (ROW). When the Yukon Government (YG) requests the powerlines to be moved to accommodate highway construction, AEY is obligated to move the powerline.

## Background

2. Placing powerlines in the highway ROW is a best practice in the utility industry to:

- Take advantage of the existing land corridor.
- Minimize additional environmental impacts by staying within an already existing linear corridor.
- Keep powerlines accessible by placing them beside roadways, reducing maintenance costs.
- Avoid the need to disturb private land and obtain easements.

3. AEY seeks permits from the Department of Highways and Public Works at minimal cost to place powerlines in the highway ROW. A condition in the permit states that:

> The applicant will bear the cost of any removal, adjustment, or relocation of the infrastructure that may be required in the future due to reconstruction, maintenance, or operation of the highway.

4. AEY started the following projects to relocate powerlines at YG's request:

- Alaska Highway – Hillcrest (stage 1 of 2);
  - YK 1027679 AEY Powerline Relocation Hillcrest YG Hwy Realignment.
- Alaska Highway – Hillcrest (stage 2 of 2);
  - Burns Road to Range Road Intersection.
  - YK 1047848 AEY Powerline Relocation Burns Rd to Range Rd Intersection.

- YK 1045669 AEY Powerline Relocation YG Alaska Hwy Crestview Phase 1 of 2;
    - 25 kV relocate in Phase 1.
    - Phase 2 was deferred due to YG roadwork delay.

## Project Descriptions, Schedules, and Costs

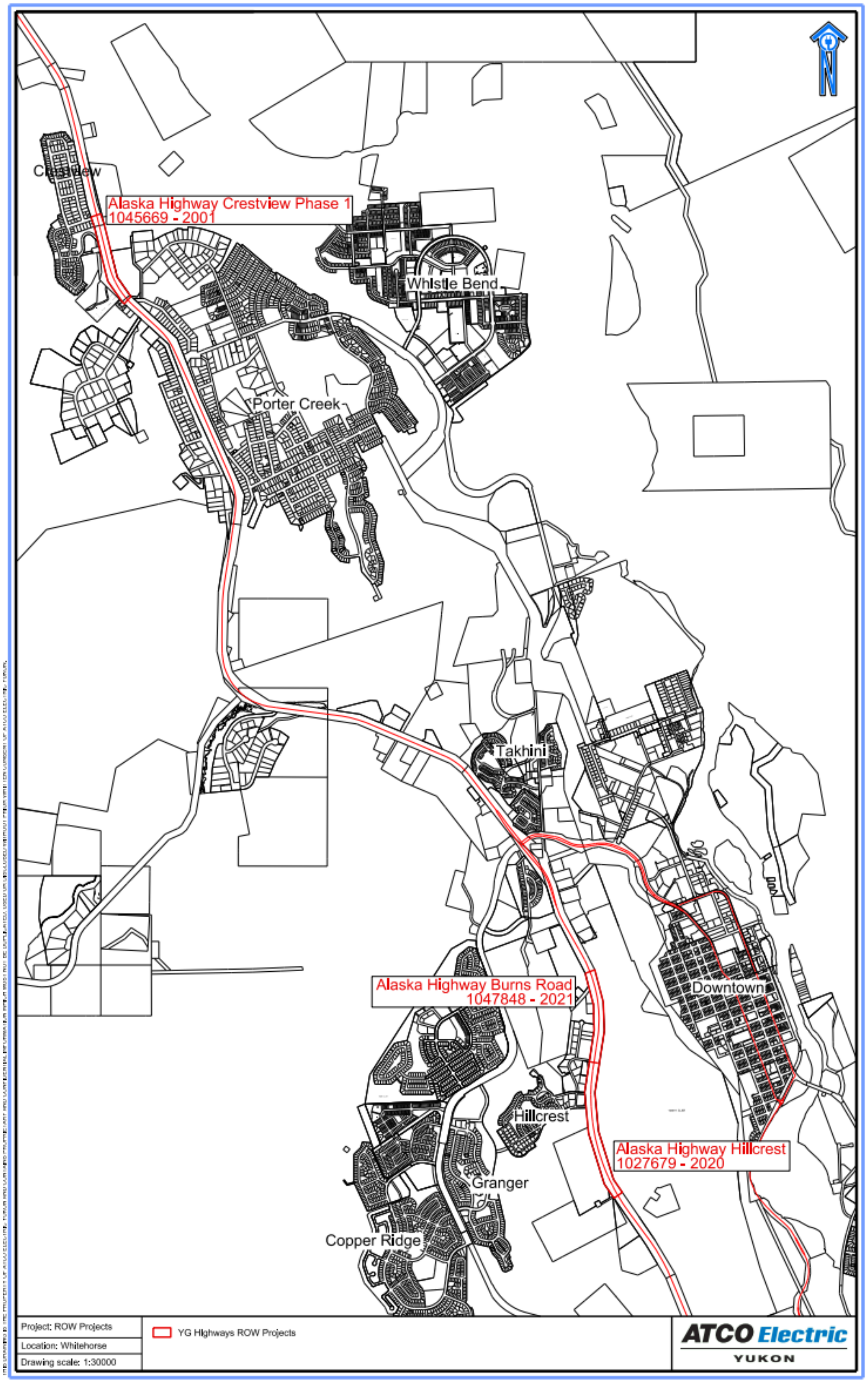
**Table 1: Project Schedules and Costs**
**($000)**

| Highway ROW Area | Completion Date | Scope of Work | Actuals |
|---|---|---|---|
| Alaska Highway - Hillcrest | 2020 | Install 7 new double circuit poles, remove 4 existing poles | 121 |
| Alaska Highway - Burns Road | 2021 | Install 7 new double circuit poles, remove 7 existing poles | 118 |
| Alaska Highway - Crestview Phase 1 | 2021 | Install 15 new poles, remove 12 existing poles | 184 |

## Appendices

Appendix A Line Move Map

## Appendix A – Line Move Map



ATCO Electric
YUKON

# 2023-2024 General Rate Application (GRA)

Dual Rated Transformer Upgrade

2018-2022 Business Case #16

## Executive Summary

1. In order to keep up with the load growth in downtown Whitehorse, the long-term plan is to change the primary voltage from 12.5 kV to 25 kV. As such, all transformers providing service to this area will need to support 25 kV service. While most pad mounted transformers in the region are dual rated for both 12.5 kV and 25 kV voltage, there are nine pad mounted transformers that will need to be converted to support a dual rating of 12.5/25 kV prior to changing the system's voltage.

## Background

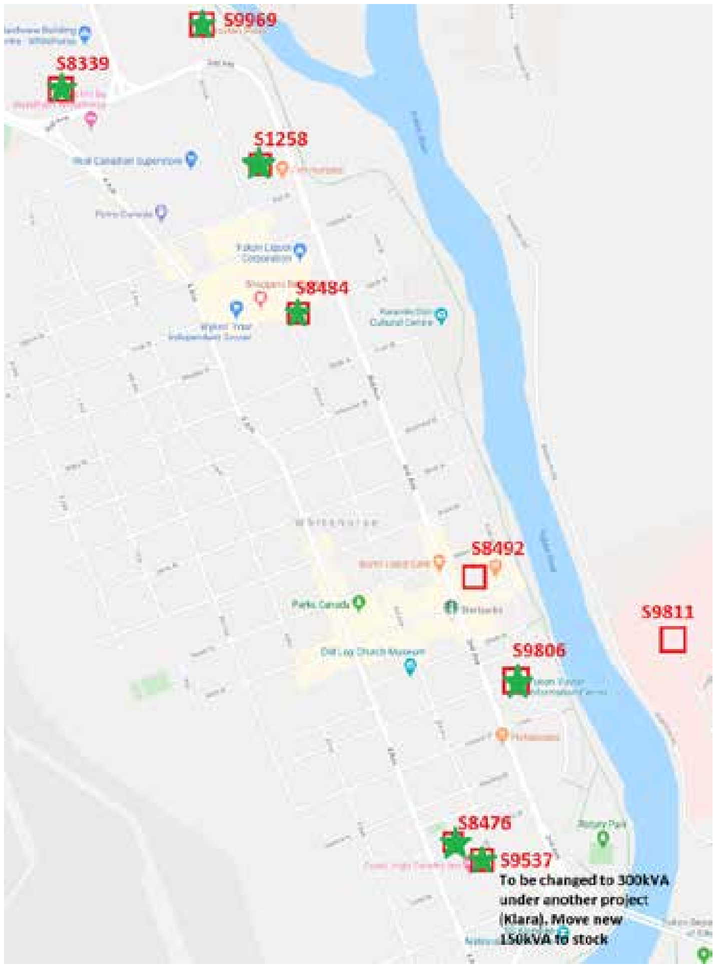
2. This is a part of a larger long-term plan to modernize the electrical supply and increase capacity of the system in downtown Whitehorse. This project was initially contemplated in 2013 but due to slower than anticipated load growth it was deferred. It was revisited within the 2016-2017 GRA and is an action item identified in appendix 9 to that filing.

3. The load in downtown Whitehorse is approaching the system's capacity. To meet this increasing load, a voltage upgrade from 12.5 kV to 25 kV is proposed for the area. This upgrade will require the electrical infrastructure in the area, including the transformers, to support both 12.5 kV and 25 kV. While most transformers in the area are dual rated, nine (9) transformers listed in Table 1 will need to be upgraded.

**Table 1: Downtown Whitehorse 12.5 kV Transformers**

| Size | Transformer Number |
|---|---|
| 150 kVA | S9537, S8339, S9806 |
| 300 kVA | S8476, S8484, S1258, S8492 |
| 500 kVA | S9969 |
| 1,500 kVA | S9811 |

**Figure 1: Transformer Locations (in progress from September 2022)**




4. Ensuring that these transformers are upgraded prior to the voltage conversion reduces the risk of scheduling issues during the voltage conversion and minimizes the demand on construction crew resources.

## Project Description

5. Upgrade nine pad mounted transformers.

6. Each transformer requires cables to be removed, the old transformer removed, new transformer positioned, cables reattached, voltage checks and verifications. Specific changeout requirements will be assessed by Construction at a pre-construction site visit for each transformer.

## Project Schedule and Cost

7. The total cost for this project was $292,761.

## Evaluation of Viable Alternatives

8. Status Quo has been the alternative of choice since the evaluation of these alternatives in 2013. However, the load growth in downtown Whitehorse has increased to the extent that the status quo no longer meets the requirements for providing a reliable supply of power and preparations for the previously contemplated conversion of the downtown area are now in process.

## Recommendation

9. Upgrading the existing transformer infrastructure is recommended as it aligns with the future voltage conversion efforts. In addition, there is substantially less outage time and system risk when compared to being required to change all single voltage transformers during one outage.

ATCO Electric

YUKON

# 2023-2024 General Rate Application (GRA)

Install 35kV Regulators on Carcross Road

2018-2022 Business Case #17

## Executive Summary

1. Voltage measurements on the 35 kV side of Carcross Substation (#301) have shown inconsistent and generally low voltages between 2015 and 2019. These values were confirmed when the area was modelled using the CYME Power Engineering software. This section of line is fed directly from the S150 substation and is not regulated. The installation of three voltage regulators ~150 meters south of Carcross cut-off along the South Klondike Highway are rated to bring voltages back within power quality standards.

## Background

2. Incoming voltage measurements at the Carcross regulators are typically inconsistent. Substation checks have found the voltage to be as low as 112 V on a -20° day. Power quality standards for voltage on a minimum 25 kV Distribution feeder require voltage to be kept at a minimum of 0.95 V per unit (114 V total).

**Table 1: Measurements at Carcross Substation from 2015-2019**

| Date | Lowest Incoming Voltage (V) | Temperature (°C) |
|---|---|---|
| March 6, 2019 | 114 | -24 |
| January 25, 2018 | 112 | -20 |
| February 22, 2017 | 113.5 | -12 |
| January 29, 2015 | 113 | -19 |

3. Using a CYME software model, with peak winter load on each substation feeder, the voltage in Carcross is estimated to be as poor as 108.2 V.

4. This issue is not believed to be exacerbated by an increased load at the substation, as the existing load on 6L18 to Carcross is expected to remain at approximately 55 A for the next 10-years.

## Project Description

5. Install three 100 A 35 kV voltage regulators on a new platform at the Carcross Road Substation. This work will require crews to install two new poles, a regulator bank

platform, and a ground grid mat. This will restore the voltage to within power quality standards and provide customers with a safe and standard service.

**Project Schedule and Cost**

6. The total project cost $196,387 to complete.

**Evaluation of Viable Alternatives**

Alternative 1:

7. Install three 100 A 35 kV voltage regulators ~150 m South of the Carcross cut-off along the South Klondike Highway.

Preliminary estimated Cost: $285,000.

Alternative 2:

8. Reconductor 6L11 and 6L18. To achieve voltages above 0.95 V per unit on the source side of the Carcross Substation, ~63 km of feeder will need to be upgraded using 795 ACSR. This alternative is not economical and so was rejected as an option.

Preliminary estimated Cost: >$1,000,000.

**Conclusion**

9. Alternative 1 is the recommended solution as it accomplishes the goal of providing electricity within power quality standards and is the least cost alternative.

ATCO Electric

YUKON

# 2023-2024 General Rate Application (GRA)

New Services Overhead and Underground

2018-2022 Business Case #18

## Executive Summary

1. New Services: Overhead and Underground is a significant component of new extensions. Most of these projects are either fully contributed or the net capitalization falls below the $100,000 and $500,000 thresholds to require a Business Case. From 2018 through 2022, there were two exceptions to this, and these exceptions are explained below.

## Background

2. New Services: Overhead and Underground projects are customer driven connections to the existing grid.

## Project Description

3. Interconnections to the existing grid.

## 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 |

## Business Drivers and Benefits

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.

**Table 2: Projects Exceeding the Net $100,000 Threshold**
**($000)**

| Description | Completion Date | Actuals |
|---|---|---|
| Boreal Common Lot 118 Tarahne Way | 2021 | 126 |
| Raven’s Inn Lot 41 Motorways | 2019 | 145 |

5. The Boreal Common Lot 118 Tarahne Way connection consists of installing two pedestals, a 750 kVA 120/208 V transformer, five bollards, 3x42 m of primary wire and 4x63 m of secondary wire.

6. The Raven's Inn Lot 41 Motorways connection was installing a large pedestal and trenching 85 m of 4x4 500 mcm secondary wire. The actual cost came in lower than the estimate mainly due to easier than anticipated digging.

**Evaluation of Viable Alternatives**

7. None.

**Recommendation**

8. Proceed with customer connections as part of AEY's obligation to provide safe and reliable service.

ATCO Electric
YUKON

# 2023-2024 General Rate Application (GRA)

My Account for Online Customer Access

2018-2022 Business Case #19

## Executive Summary

1. This My Account solution provides customers with the ability to access their accounts at any time through an online portal on ATCO's Web page. Customers can make payments, view details, communicate with AEY and manage their accounts through this portal.

## Background

2. Customers of AEY currently do not have the ability to access their account or pay their bills on-line. It is the number one request received from customers. AEY wanted to explore the possibility of offering its customers an online offering without having to make a large capital investment in technology to do so. In late 2017, AEY received a demonstration of ATCO Energy's customer portal – My Account, which was launched to customers in 2016. My Account had the capabilities AEY required to satisfy its customers' requests. AEY engaged WIPRO to explore the possibility of extending that functionality to make it available to its customers.

3. This represents a significant opportunity for AEY to provide online capability to its customers in a compressed delivery timeframe. For those customers who sign up for the service, this functionality will improve customer service and contribute to increased overall customer satisfaction.

## Project Description

4. The project will be contracted to WIPRO and managed by a Project Manager from the Global IT group. WIPRO has provided a preliminary estimate of $161,385 to create the portal, similar to ATCO Energy's existing service, and complete all required work and testing to ensure the platform is workable for AEY. Global IT will provide project management and oversight of the project at 20 percent of project costs. To inform customers of the new service there will be promotional advertising put in place once the project is operational.

## Project Schedule and Cost

5. The total capital project cost is $265,622 and was completed in 2019.

6. In addition, there are ongoing O&M fees with the forecasted breakdown below.

**Table 1: Forecasted O&M Fees**

| Ongoing Fees | Cost ($) |
|---|---|
| AMS Projected Monthly Cost (Silver) | 2,320 |
| DR Service (annual cost of $2,137) | 178 |
| Oracle Cloud Hosting Fees | 2,960 |
| **Total Ongoing Fees Estimate** | **5,458** |

**Business Drivers and Benefits**

7. This project aligns with Customer Centricity and AEY making energy easy for our customers. There will be efficiency gains as customers migrate to a 'self-service' model for common service requests. Though we are unable to quantify the shifting workload, as much of the current customer engagement is either 'walk in' or on the phone, we expect less reactive work with our customers. This will allow a review of the front office business model to match our customer's needs.

8. Adding new benefits or service to customers:

- My Account provides the customer access to their account 24 hours a day – at their convenience. They are no longer required to coordinate with AEY office hours.
- Customers will be able to access their account information and pay their bills online, which is a consistent request from customers.
- Customers are able to request services, update information and print consumption reports on their own at any time.
- Customers will have the ability to pay via Credit Card without manual input by employees.
- Customers are able to view up to 24 months of consumption from the portal.
- Customers will have access to their current bill the day after it statements, a week earlier than current which can reduce late charges.

9. Additionally, the project will reduce paper and envelope usage and lower costs for postage and E-post charges. Customers will also no longer have to wait to receive their bills through Canada Post.

**Evaluation of Viable Alternatives**

Alternative 1

10. Create an online customer portal using the My Account Portal technology that is currently in use by several ATCO Companies.

Alternative 2: Status Quo

11. Continue to provide only in person manual service to customers during regular office hours.

**Recommendation**

12. Proceed with Alternative 1 and create an online customer portal using the My Account technology as there is a real business need to offer online account access and updated payment options to AEY's customers.

ATCO Electric

YUKON

**2023-2024 General Rate Application (GRA)**

Streetlights Hart Crescent

2018-2022 Business Case #20

## Executive Summary

1. Replace sixteen streetlights and cable on Hart Crescent in Whitehorse.

## Background

2. The cable and steel poles are nearing end of life. There had been a fault on Alsek Road adjacent to Hart Crescent. The failure on the edge of the crescent prioritized this area for the next logical replacement project. This case is one part of an overall streetlight replacement program to replace end of life equipment and bring the installation up to current code.

## Project Description

3. Trench as required, install new conduit and cable. Install 16 new concrete streetlight bases with new steel poles and LED lights. Remove all old light poles and HPS lights.

## Project Schedule and Cost

4. The project cost $180,176 and was completed in 2021.

## Business Drivers and Benefits

5. The underground cable feeding the streetlights is nearing end of life. One cable break has been repaired to date. The cable is direct buried and needs to be excavated to be repaired when breaks occur.

6. The benefits of installing concrete bases and cable in conduit are that it allows for quicker replacement of failed components in the future. The number of failures due to aging cable will be reduced.

## Evaluation of Viable Alternatives

<u>Alternative 1</u>

7. Repair breaks as they occur and defer wholesale replacement until pole and cable failures increase beyond an acceptable amount.

8. This alternative was rejected as Operations prioritized Hart Crescent Streetlight replacements in the long-term streetlight rebuild plan.

**Recommendation**

9. In line with the long-term streetlight rebuild plan, replace the streetlights on Hart Crescent with cable in conduit and concrete bases for the steel poles.

ATCO Electric
YUKON

# 2023-2024 General Rate Application (GRA)

Swift River Unit 2 Replacement (CUL 544)

2018-2022 Business Case #21

**Executive Summary**

1. Through the Swift River Generating Facility, AEY provides power to approximately 19 customers. AEY has a duty to provide safe and reliable electrical service, which includes the prudent replacement of aging infrastructure. At this location, AEY has two installed generating units to provide N-1 capacity.

2. One of the generating units at the facility, Unit 2 (CUL 544), was installed in 2013 and is approaching its end-of-life at 30,000 operational hours based on manufacturer's specifications. Therefore, AEY is recommending this generator be replaced with a new diesel generator.

**Background**

3. The Swift River Generating Facility currently provides power for the YG HPW camp and local residences on a small remote grid. A map of the communities served in the Yukon can be found in Appendix A.

4. The Swift River Generating Facility houses two diesel generating units. Generating Unit 2, CUL 544, was manufactured in 2012 and is approaching its manufacturer's recommended end-of-life at 30,000 operational hours. Based on the manufacturer's guidelines, there are no life extensions for these types of units beyond 30,000 hours. It is prudent to replace these generators prior to this operational mark as it saves on costly repairs and lowers the risk of an unplanned outage.

5. AEY has executed three similar projects of this nature (CUL 352 Replacement in 2018/2019, CUL 257 Replacement in 2016, and CUL 258 Replacement in 2013) at this facility. Based on average runtime, it is expected that Unit 1 will require replacement in 2025/26.

**Project Description**

6. The scope of the project is to remove CUL 544 and replace it with a similarly sized unit. This would require the removal of the genset and radiator, reusing the existing silencer. After a new unit is purchased, the install process will be as follows: remove the

existing unit, install the new unit, integrate the unit into existing electrical supply and control systems, and connect the unit into cooling, waste heat, exhaust, and fuel system. Backup generation will need to be operational onsite during construction.

7. Federal emissions require the replacement of the radiator to accommodate charge air cooling.

**Project Schedule and Cost**

8. Actual costs were $226,589 and the project was completed in 2022.

**Business Drivers and Benefits**

Cost Effective Replacement Timing

9. CUL 544 will reach its manufacturer's specified end-of-life at 30,000 operational hours in 2021 based on average annual operational hours. Continued operation is not recommended for high RPM generating units with high operational hours, due to increased maintenance and decreased reliability. AEY has been consistent in its approach to replacement of high mileage units rather than refurbishments due to limited operational return of investment.

**Evaluation of Viable Alternatives**

Alternative 1: Status Quo – Maintain Existing Unit and Perform Life Extension Maintenance

10. Continue operating as normal and perform a major overhaul on CUL 544. Based on previous operational experience, AEY has seen marginal improvements in continuing to operate generator units beyond the manufacturer's specification. The manufacturer does not have guidelines for life extension beyond 30,000 hours so maintenance may not be successful. Therefore, the site would be left with no spare capacity (N-1) and be subject to increasing outages and downtime. Cost of parts and labour is estimated to escalate over time and would likely exceed the cost of a replacement in short order.

Alternative 2: Tie Served Community to Existing Yukon Transmission System

11. A second alternative would be to connect the served customers to an existing distribution system (i.e., Teslin or Watson Lake). This requires significant design and engineering and would not be executed before CUL 544 exceeds the 30,000 operational hour mark and thus is not recommended.

Alternative 3: Replacing CUL 544

12. Replace CUL 544 with a new generator of a similar size. Replacement work would be completed by third party vendors with AEY overseeing the installation. This alternative would cost approximately $160,000 and would be installed by end of year 2021. It is the least cost alternative that addresses all immediate concerns of CUL 544 exceed the manufacturer's operational hours.

## Recommendation

13. AEY recommends Alternative 3 – Replacing CUL 544. Delivering power safely and reliably is AEY's primary driver. To do so, AEY must ensure that its equipment is prudently upgraded before it becomes an operational liability. It is an opportune time to replace an aging generator, CUL 544, prior to major maintenance and the expected decrease in operational efficiency. Neither of the two other alternatives will address the issues at a cost competitive price or appropriate timeline.

## Appendices

Appendix A Service Areas and Facilities of ATCO Electric Yukon

## Appendix A: Service Areas and Facilities of ATCO Electric Yukon