ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

ATCO CIS Replacement

2023-2024 Business Case #22

Executive Summary

1. Lifecycle replacement of ATCO Computer Information Systems (ATCO CIS) with Oracle Customer Cloud Service Solution (CCS) to mitigate risks associated with the current (end-of-life) system and to provide AEY with the right tools to perform Customer Care and Billing (CC&B) in an accurate, reliable and efficient manner.

Background

2. ATCO CIS was built in the early 1990s and is at end-of-life. As a result, it is increasingly costly and difficult to maintain the underlying COBOL programming language as well as add functionality. In particular, the internal personnel that understand the highly customized nature of ATCO CIS are beginning to retire, and the number of skilled COBOL programmers in the marketplace is decreasing. The combination of these effects contributes to the increasing costs to maintain and support ATCO CIS.

3. Furthermore, the cyber security risks increase with continued use of an antiquated system compared to modern software applications that are designed to minimize the ever-increasing risk of malicious attackers taking advantage of application vulnerabilities. Given that ATCO CIS enables critical business functions fundamental to AEY's regulated, integrated electric distribution business, the risk of not replacing ATCO CIS is too great.

4. In addition, AEY and its systems must be flexible, supportive, and responsive to increasing demands of electrification, including renewable technologies such as solar panels, as well as increasing the complexity of the billing systems. The replacement of the legacy ATCO CIS will allow AEY to continue to meet its billing requirements and ensure needs can be met in the future.

Project Description

5. The ATCO CIS system was built in the early 1990s and is used by the ATCO Utilities, including AEY. Due to the age and highly customized functionality of ATCO CIS, and consistent with the conclusion of a third-party report, it was determined

that continuing to rely upon ATCO CIS posed too great of a business risk and should be replaced. As a result, ATCO conducted a procurement process to compare Oracle CCS against Tier 3 niche products (Vertex 1, Cogsdale and Cayenta) available in the marketplace for fully integrated utilities that serve less than 100,000 customers. The evaluation confirmed Oracle CCS as the best alternative.

6. In addition to achieving the lowest cost option for customers, the goals of the project are: to maximize out-of-the-box functionality and minimize customization to facilitate lifecycle management, minimize future operating costs and risk, maintain a high level of customer care and billing service, support regulatory requirements, and reduce technology risk. AEY will, as required, utilize the specialist(s) within ATCO to support Oracle CCS and related functions, including vendor support and CCS updates.

7. With the move away from CIS as it is no longer supported and the increased functionality of the CCS program there are increased operating costs which are outlined in the Project Schedule and Cost section below.

Resources Required

8. In general, resources will be staffed through a combination of internal ATCO business employees and contractors (i.e., direct labour). AEY also leveraged the expertise of TMG Consulting during the procurement process.

Project Schedule and Cost

Table 1: AEY Project Schedule and Capital Cost

Year	Cost ($)
2021	680,000
2022	3,712,000
2023	3,666,000
2024	345,000
Total	**8,403,000**

9. In addition to the above capital spend, the CIS program will require an increase in O&M expenditures to operate the cloud-based system. A breakdown of the costs in

the Test Period, an offset for the licenses fees for the old system and the incremental increased fee charged to YEC are included to show the net impact to O&M costs.

Table 2: Net Operating and Maintenance Costs ($000)

	2023[1]	2024
Operating Costs	400	700
YEC Payment[2]	(60)	(100)
Average Licenses Fee[3]	(105)	(185)
Net Additional O&M	**235**	**415**

Business Drivers and Benefits

10. The business drivers and benefits of the ATCO CIS Replacement are as follows:

- ATCO CIS is a critical system relied upon to manage all aspects of the meter to cash cycle. Without a working and capable CIS, AEY would be unable to accept new customers, manage customer moves, calculate usage and charges, bill customers or collect and manage revenue.
- Sudden or unexpected outages could have negative impacts on AEY's ability to maintain acceptable levels of CC&B and meet its obligation to serve customers.
- Existing CIS is end-of-life.
- Cybersecurity threats – modern software applications are designed to minimize the ability of attackers to take advantage of application vulnerabilities.
- Availability of resources – the number of skilled COBOL programmers in the marketplace is decreasing, creating a significant and growing skills gap. The number of experienced and qualified internal resources continues to decline as ATCO CIS ages.
- As AEY's parent company is transitioning away from the use of CIS there will be fewer internal resources to support its use.
- The electricity industry is currently undergoing a transformation, including electrification (electric vehicles and Distributed Energy Resources). CCS provides two-way communication between utilities and customers, which

[1] The dollars in 2023 are prorated as CIS will not be in service for the entirety of 2023.
[2] This is the incremental increase in payment from YEC above what was being paid with the previous system.
[3] These are based on a five-year average of license fees AEY paid for the previous system.

will better enable of price signals through rate design such as time of use (TOU) rates.

- Oracle CCS was selected because of the high degree of functional fit with business requirements, and technical compatibility, as well as integration because AEY already utilizes Oracle Enterprise Resource Planning software.

- Finally, Oracle CCS is a subscription-based service which includes a cyber security component which helps maintain protection from cybersecurity threats.

Evaluation of Viable Alternatives

Alternative #1: Status Quo

11. AEY continues to operate ATCO CIS. This option is neither acceptable nor feasible given the business drivers identified above. The ATCO CIS system is end of life and requires replacement. In addition, no other ATCO utility will be using ATCO CIS beyond 2024.

Alternative #2: Replace ATCO CIS with Oracle CCS

12. This option reduces the risk of a critical system failing and reduces cyber security threats. This option is the lowest cost alternative to customers, as AEY will utilize the expertise gained from ATCO Utilities for both implementation and to perform CC&B services.

Alternative #3: Replace ATCO CIS with Tier 3 Commercial Off-the-Shelf Solution

13. This option reduces the risk of a critical system failing and reduces cyber security threats. However, this option is more costly as it requires specialized implementation resources and training to use the system (e.g., interface training, upgrades and maintenance).

Recommendation

14. ATCO CIS is end-of-life and requires replacement. AEY recommends proceeding with the replacement of ATCO CIS with Oracle CCS, as detailed above. The business

risk associated with continued use of ATCO CIS is unacceptable. Replacing ATCO CIS with Oracle CCS is beneficial to AEY and its customers.

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2023-2024 General Rate Application (GRA)

Genset Major Overhauls

2023-2024 Business Case #23

Executive Summary

1. AEY conducts major overhauls on diesel gensets based upon manufacturer recommended intervals for each individual equipment, to ensure ongoing reliability and availability.

Background

2. AEY has a fleet of 18 isolated power diesel gensets and eight (8) community standby / peak shaving diesel gensets along with four (4) mobile diesel gensets. AEY conducts regular servicing and major maintenance activities based upon the specific OEM runtime-based recommendations.

Project Description

3. The scope of a major overhaul is defined by equipment OEM manuals. The work is contracted to qualified third party service providers.

4. Occasionally, engine blocks are changed out when this is more cost effective than an overhaul or completely new genset. The changing out of engine blocks are capitalized since they are end-of-life replacements of major equipment.

Project Schedule and Costs

Table 1 - Major Overhauls - 2017-2022
($000)

Generating Unit	Project #	2017	2018	2019	2020	2021	2022	Notes
Destruction Bay-1	Y14009	$140						
Watson Lake-4	Y14391		$369					
Beaver Creek-2	Y14468		$126					
Pelly Crossing-3	Y14469			$110				(1)
Old Crow-2	1022317			$71				(2)
Old Crow-1	1030628				$465			
Beaver Creek-3	1050918					$317		
Destruction Bay-2	1050920					$174		
Beaver Creek-1	1050919					$175		
Destruction Bay-3	1050915					$96		
Old Crow-4	1069354						$252	
Watson Lake-5	1069355						$479	

(1) New block more cost-effective than overhaul / replacement.
(2) New block due to failure, more cost-effective than genset replacement. An overhaul could not be performed due to the damage caused by the failure.

5. Using AEY's standard practice of performing major overhauls on units based on the five-year average runtime, the units WL-2 and WL-4 have been identified as requiring an overhaul in 2023 and 2024. These were identified using the last service interval and current hour reading.

6. Based upon the forecast and the OEM recommended interval for major overhauls, these two units require an overhaul after 24,000 hrs of runtime. AEY currently performs runtime predictions on its Genset units to identify when it will require overhauls. WL-2 was installed 2016 and will have its first major overhaul, and WL-4 was installed 2013 and had a major in 2018.

7. Below are the cost estimates for the two generating units, which are based upon actuals for similar equipment plus recently observed inflationary pressures and logistical challenges:

Table 2: Project Schedule and Cost
($000)

Generating Unit	2023	2024
WL-2	$375	
WL-4		$515

Business Drivers and Benefits

8. Continued inspection, component replacement, and equipment servicing ensures ongoing availability and reliability of generating stations and reduces overall lifecycle cost.

Evaluation of Viable Alternatives

9. There are no viable management alternatives.

10. Options with respect to the need for runtime-based overhauls:

(1) Run Components to Failure:

(a) This is not a desirable management method, as it reduces isolated grid reliability (unplanned and extended outages) and increases ratepayer costs.

(2) Condition-Based Maintenance:

(a) AEY does not have the asset management systems or capacity to be able to extend overhaul frequencies using analytical condition monitoring of equipment.

(b) This maintenance is done based on the condition of the asset. Currently, AEY is relying on a statistics-based maintenance approach which is determined by the manufacturer's recommendations.

11. AEY forecasts timing of overhauls based upon past runtime trends, and schedules future work with qualified contractors to limit operational impacts. There are no viable resourcing alternatives. The reason this is not conducted using internal resources is:

- This work is sporadic year-on-year and requires specific skills sets, competency, and training. It is not cost advantageous to have on-staff mechanics and electricians.

- ATCO is not a large global purchaser or installer of engine components so does not have the procurement power or warranty facilities of large service organizations that have this as their prime business activity.

Recommendation

12. Continue to perform major overhauls on units based on the five-year average runtime.

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2023-2024 General Rate Application (GRA)

Asset Management Program

2023-2024 Business Case #24

Executive Summary

1. In 2022, AEY undertook a business-wide gap assessment of its Asset Management (AM) practices against ISO best practices. METSCO Energy Solutions Inc. assisted AEY's leadership group in defining a vision for AEY's future state of asset management, along with developing a five-year roadmap for step-wise improvements that will result in AEY achieving its objectives and being in alignment with how utility peers manage physical infrastructure. Starting in 2023 and continuing into 2024, AEY is proposing to begin implementation of this five-year roadmap with the priorities that have been identified.

Background

2. Refer to the attached Asset Management Assessment by METSCO Energy Solutions Inc. (METSCO Report), Business Case #24 Attachment 1.

3. AEY was evaluated in five different operational areas that align with AM subjects. Please refer to Figure 3-1[1] and Table 3-2[2] of Business Case #24 Attachment 1.

4. This study examines where AEY operations are with this model and provides recommendations for improvements. By implementing these recommendations, AEY will be able to be more proactive with asset lifecycle delivery and better able to plan and respond to changes in technology and regulations.

5. AEY's maturity level was graded and compared to METSCO's knowledge of other peer utility organizations and in most categories, AEY was behind its peer group. Please refer to Table 3-3[3] of Business Case #24 Attachment 1.

6. The table below summarizes the results of the review.

[1] Business Case #24 Attachment 1, METSCO Report, Figure 3-1, PDF page 10.
[2] Business Case #24 Attachment 1, METSCO Report, Table 3-2, PDF page 11.
[3] Business Case #24 Attachment 1, METSCO Report, Table 3-3, PDF page 12.

Table 1: Comparison of AEY to Peer Group

Category	Peer Group	AEY
Capital Planning	Developed	Aware-Developing
Maintenance & Operations	Developed	Developing
Records Management	Developed	Aware
Finance & Corporate Reporting	Developed	Developed
Enterprise Risk Management	Developing-Developed	Aware

7. There are several drivers to improve AEY's performance in this area:

(1) AM Evolution – The AM practice represents an integral component as part of the utilities' ability to develop objective, prudent and accurate capital and maintenance investment plans as well as the underlying decisions to support these plans.

(2) Regulatory Awareness – Regulators across Canada are introducing new requirements or expectations for utilities to have established comprehensive asset management practices that allow for the proactive replacement of assets, such that risks are being mitigated and value to the customer is being enhanced.

(3) Operational Efficiency / Cost Effectiveness – improvements in AM are expected to help balancing budget and human resources to the pressures of system needs including aging infrastructure.

Project Description

8. The initial focus in 2023 and 2024 is for AEY is to introduce foundational analytics and documentation into its AM framework, i.e., priority 1 tasks as defined within the METSCO report. Please refer to Figure 4-1[4] of Business Case #24 Attachment 1.

[4] Business Case #24 Attachment 1, METSCO Report, Figure 4-1, PDF page 32.

Project Schedule and Costs

Table 2: Project Schedule and Costs ($000)

Element	2023 Forecast	2024 Forecast	Total Forecast
Asset Health Index	100	50	150
AM Policy	20	-	20
Strategic AM Plan	25	-	25
Asset Management Plans	25	75	100
Capital and O&M Spending Decision Process	10	15	25
Maintenance Manuals	-	200	200
Enterprise Asset Information Strategy	25	100	125
Update Asset Registry	50	50	100
Critical Operations Contingency Plans	-	135	135
Organizational Strategy and Local Business Plan	-	110	110
FTE – Asset Manager	50	166	216
TOTAL	**305**	**901**	**1,206**

9. The above table is a summary of the project steps identified in Table 4-2[5] of the attached METSCO report, Business Case #24 Attachment 1, with forecast budget and timing identified.

Business Drivers and Benefits

10. Please refer to Table 2-1[6] of Business Case #24 Attachment 1 for the AM Benefits.

11. Benefits of individual incremental improvements in the roadmap[7] are highlighted within the METSCO report, Section 4.

Evaluation of Viable Alternatives

12. 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.

13. Please refer to Table 1-1[8] of Business Case #24 Attachment 1, METCO Report.

5 Business Case #24 Attachment 1, METSCO Report, Table 4-2, PDF pages 33-35.
6 Business Case #24 Attachment 1, METSCO Report, Table 2-1, PDF page 8.
7 Business Case #24 Attachment 1, METSCO Report, PDF pages 32-42.

Recommendation

14. Proceed with the roadmap, while assessing and adjusting to account for roll-out success and alignment with steering committee vision.

[8] Business Case #24 Attachment 1, METSCO Report, PDF page 4.

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Asset Management Assessment

Prepared For: ATCO Electric Yukon
Prepared By: METSCO Energy Solutions Inc.
8 February 2023

ATCO Electric
YUKON

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1 Executive Summary

ATCO Electric Yukon (AEY) is commissioning an independent assessment of its Asset Management (AM) practice. As part of a review of its practices, AEY is looking to identify enhancement opportunities to meet external drivers such as alignment with utility peers and address internal drivers such as technology obsolescence, aging infrastructure, and resource limitations which will require good planning, significant investments, and a shift in the utility strategy. By commissioning this assessment and, by inference, taking this next step in its Asset Management journey, AEY will be able to adopt practices and supporting analytics to meet these emerging challenges and build on top of its foundational practice of maintaining and applying investment prudence with its physical assets.

METSCO Energy Solutions Inc. (METSCO) was contracted to conduct the independent maturity assessment by applying the ISO 55001 standard, to identify AEY's level of asset management maturity and recommend areas for improvement for the next phase of AEY's asset management development. The assessment uses a 5-scale rating, ranging from 'Aware' alignment to 'Optimal' alignment to rank the maturity of asset management practices in AEY's operations when compared to industry-leading benchmarks. The following table summarizes the results of AEY's maturity assessment. ISO55001 defines many characteristics and attributes of asset management for physical infrastructure and METSCO has developed a fit-for-purpose framework of assessment based upon AEY's operational areas in order to create action-based recommendations that will improve the maturity and practice of asset management for the specific scale and complexity of the business.

Table 1-1: AM Maturity Scale

AM Maturity Scale				
Aware	*Developing*	*Developed*	*Enhanced*	*Optimal*

AEY Operational Area	Description	**AEY's** Avg. Maturity Ranking
Capital Planning	Consists of the organization, strategy, and processes in place for planning and executing the programs with supporting objectives linked to KPIs.	Developing
Maintenance & Operations	Consists of the organization, strategy, and processes in place for planning and executing the programs with supporting objectives linked to KPIs.	Developing
Records Management	Ensuring that the information architecture, processes, operational and asset data, and tools are in place to support asset-related decisions.	Aware
Finance & Corporate Reporting	Ensuring that the information architecture, processes, operational and asset data, and tools are in place to support asset-related decisions.	Developed
Enterprise Risk Management	Ensuring that the organization has a continuous advancement culture to operate and maintain its asset management practice regarding corporate risks.	Aware

In the interest of being thorough, the report outlines a complete list of focus areas with actions, whose acceptance and execution would lay the foundation for increased maturity as defined by the referenced standards and result in AEY's closer alignment with utility peers. However, we acknowledge AEY's responsibility to deliver safe and reliable service to its customers at a reasonable cost, a feat that can be accomplished with alignment as opposed to certification in ISO 55001. The intent is to present a 5-year improvement plan that is prioritized and sequenced, which results in incremental steps towards a more mature practice. In aggregate, the 5-year roadmap is estimated to cost greater than $2M to implement and create comprehensive organizational and operational change. We recommend assessing and evaluating the suggested focus areas and considering the benefits and practicality of each, before incorporating them into a final execution plan.

2 Introduction

2.1 Purpose and Context

METSCO assessed the alignment of the asset management practices currently used by ATCO Electric Yukon (AEY) to manage their assets with the requirements of ISO 55000, the industry-accepted standard for asset management systems. In so doing, differences between the current state and that which defines a mature asset management system were noted. Further, actions to address these differences were presented as candidates for stepwise change in AEY's next phase of its asset management journey.

AEY is a branch of the North of 60 business unit within ATCO Electric (ATCO) and has been responsible for the construction, operation, and maintenance of the low voltage overhead and underground power system, including poles, wires, substations, generating stations, and streetlights, within Yukon over the past 120 years. AEY provides service to approximately 19,000 customers across 19 different Yukon communities. Furthermore, AEY is a prime generator operating in isolated grid communities. The assets servicing isolated grid communities are critical to AEY's expected performance further highlighting the importance of managing assets with practices aligned to industry practice.

AEY has been continuously improving its planning and operational processes to enhance the delivery of its capital and maintenance investment plans. To support the enhancement of these processes, AEY requested METSCO to assess AEY's current-state asset management practice, to review and articulate AEY's state of infrastructure asset management and to assist in the preliminary setup of a business-wide asset management strategy. As part of the review, AEY is seeking areas for improvement to be identified, prioritized, and justified into a development and execution roadmap.

Several drivers comprise the context for this initiative and define the key challenges that support the necessity of the project work. A few of these drivers are provided below:

- Asset Management Evolution – The asset management practice represents an integral component as part of the utilities' ability to develop objective, prudent and accurate capital and maintenance investment plans as well as the underlying decisions to support these plans. ATCO, which represents the parent organization to AEY, has an established asset management framework, organization, and protocols. However, this established framework may not be practical or economically balanced for AEY's unique business circumstances. AEY has not implemented ATCO's corporate asset management practices within their business units. The outputs produced through this initiative will assist AEY in developing a "right-sized" asset management system.
- Regulatory Awareness – All utilities in Yukon, including AEY, are regulated by the Yukon Utilities Board (YUB). The YUB has not established nor prescribed any asset management standards or guidelines to utilities. In addition, the YUB does not publish reliability or performance-based expectations for utilities. In general, however, regulators across Canada are introducing new requirements or expectations for utilities to have established comprehensive asset management practices that allow for the proactive replacement of assets, such that risks are being mitigated and value to the customer is being enhanced.
- Operational Efficiency/Cost Effectiveness – AEY continues to face challenges in delivering efficient and cost-effective electricity to their customers. System needs, including aging asset infrastructure, must be balanced against the availability of resources such as budget and human resources. The enhancement of the utility's asset management system and practices

is expected to produce strategic improvements that will assist in the resolution of this challenge.

2.2 Asset Management Defined

Asset management provides a systematic approach to capturing value from tangible (physical) assets from initial procurement through to disposal. This range of activities is often referred to as the "asset lifecycle," where with the assistance of data-driven methodologies, an organization can efficiently manage its physical assets, optimizing the trade-offs between cost (i.e. reducing long-term cost while maximizing return on investment), performance (i.e. provide safe and reliable service to customers), and asset risk (i.e. implementing mitigating strategies and tactics to operate within risk tolerance thresholds established by key stakeholders). Though regulated utilities have been managing assets for over 100 years, the key elements to capture through asset management include:

- Definition of roles and responsibilities addressing governance around the asset management program implementation, as portrayed in Figure 2-1.

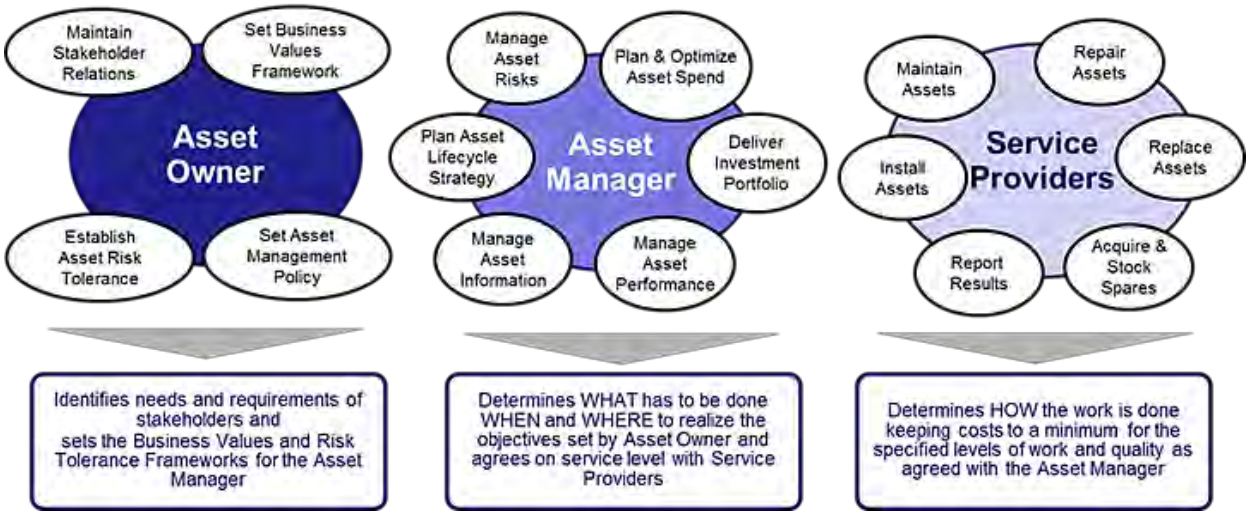


Figure 2-1: Process Responsibilities

- Documentation regarding "sources of truth" for asset demographical, criticality, condition, and performance data and information. Integration of this data and information to, in concert with subject matter experts, direct decisions regarding the purchase, operating regimens, repair, and/or replacement of assets.

    - In accomplishing this, standard approaches, and methodologies inform the decision to repair/replace or fix on failure:
        - *Asset criticality*: a measure of an asset's importance to the system.
        - *Condition monitoring*: fine-tuning current test and inspection programs to inform the measurement and monitoring of asset health and condition.
        - *Asset health indexing*: converting asset condition information into a likelihood of failure calculation and determination of effective age.
        - *Asset failure forecasting*: applying asset health indexing as a leading indicator when coupled with criticality insights.

- Reinforcement of the current capital investment and O&M spending portfolio development processes with analytics to transparently optimize the trade-off between value (contribution of an investment or program to business strategy) and risk of deferment.

- Development of asset-specific strategies often referred to as asset lifecycle plans or asset management plans for the major asset types, i.e. those that are deemed most critical in terms of risk mitigation, reliability, and lifecycle cost, is one perspective to consider. Also is profiling their key attributes and characteristics, tracking their performance and failure rates over time, and determining asset criticality. This will require the development of a process to categorize individual assets by criticality, a measure of an asset's importance to the system, which once monetized, can inform the monetization of the consequences of an asset failure.

- Establishment of Key Performance Indicators (KPIs) that reflect a mix of lagging performance measures that monitor the past performance of assets, and leading indicators to predict future performance/anticipate failures, aligned to the organization's strategic objectives via a Business Value Framework.

2.3 Proposed Areas for Assessment and Asset Management Benefits

A full listing and description of further improvement opportunities are provided in Section 3.0. These areas emanate from the maturity assessment and are identified to spur a review of their role in AEY's plan to take asset management to the next step. In so doing, the overarching objective will be for AEY to:

- Develop a program (or system) that drives congruence between overall business strategy, an underlying philosophy in managing its assets, and the use of personnel in capturing value.

- Establish practices and analytics [1] that provide transparency to and optimize the trade-offs between cost, performance, and risk in managing critical assets.

- Identify the responsibilities and competencies required to affect the tie between people, process, and technology in fulfilling its asset management vision.

- Define the technological capabilities (i.e.: IT/OT enablement) to accelerate the execution of established processes and practices, boost the accuracy of asset condition and performance data, and further sharpen the targeting of asset management-related interventions to enhance performance.

The benefits to be derived from asset management touch the full gamut of business drivers, most notably the execution of optimum maintenance regimens, development of well-conceived and balanced capital investment portfolios, and implementation of a holistic approach to identifying, categorizing, and mitigating asset risk relative to preconceived risk level thresholds.

There are advantages to be realized by an improvement in AEY's asset management maturity level, some of which are detailed within the recommended actions in section 4 of this report. The focus is

[1] Specific practices and analytics include Economic Lifecycle Modelling (i.e.: Identification of Degradation Processes, Asset Health Indexing, Generating Failure Probability Curves, and determining Consequences of Failure Scenarios) and Capital Investment and O&M Spending Portfolio Development (determining the extent to which an investment or program contributes to the overall strategy and an assessment of the risk of its deferment for a future budget cycle).

on assets used to generate and deliver electricity to customers; however, benefits can be extended to incorporate other asset classes such as general plant, property, and fleet.

Table 2-1: Asset Management Benefits

Attribute	Benefits
Processes and Practices	• Upgraded processes and practices leading to enhanced performance and lower costs. • Well-defined and repeatable processes to create a stable, reliable, and scalable system for getting work done and making decisions. • Enhanced asset health and condition/operating metrics to drive asset decisions. • Improves risk mitigation and awareness.
Competencies	• People are trained and qualified to monitor, operate, and maintain equipment to established and consistent standards. • Renewed focus on enhancing critical skills. • Equipped to make decisions based on data.
Systems	• Enhanced and integrated data systems provide relevant and quality information on equipment and system operation, condition, and history.
Organization	• Alignment of organizational responsibilities enhances the efficiency of decision-making and clarifies accountabilities. • Roles are more clearly defined in the delivery of work, and performance of the work can be measured against targets
Tools	• Adoption of analytical tools to evaluate and prioritize investment options based on risk, financial return, and contribution to corporate strategy. • Enhanced asset data and information regarding condition, criticality, operating regimen, and maintenance history assists in making informed decisions.

This all translates to greater efficiencies in the performance of work, well-directed capital investment (i.e. better lifecycle cost management), and a accountable risk management decisions while delivering safe and reliable electric service. The introduction and continued enhancement to the utilities' asset management practice can introduce savings for utilities, including a reduction in operating costs of up to 15% for overhead and underground lines, and up to 20% for substation equipment [2].

[2] R. de Sousa, D.G. Fernández, J.R. Gonzalez, H. Tai, "Harnessing the power of advanced analytics in transmission and distribution asset management", McKinsey & Company, 2018. URL: https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/harnessing-the-power-of-advanced-analytics

3 Assessment of AEY's AM Practice

3.1 Methodology

To assess AEY's Asset Management (AM) practice, METSCO delivered a three-step process:

- Assessment of current-state asset management practice: Establishing a baseline understanding of AEY's underlying processes, systems and data that are being used to support decision-making applications and outputs.

- Comparison with peer group and industry standards: Leveraging the current-state baseline results, compare AEY's AM practices against similar-sized peers as well as industry standards and practices.

- Identifying opportunities for improvement: Leveraging results from the current-state assessment and the peer group comparison, suggest right-sized opportunities for improvement in AEY's AM practices.

The following subsections serve to provide further details on the three-step process and the associated methodologies that were applied.

3.1.1 Assessment of Current-State AM Practice

To effectively evaluate AEY's current-state AM practices, it was necessary to first establish an evaluation framework that considered leading industry practices as they relate to asset management. Through METSCO's investigations, the ISO 55000 family of asset management standards were identified as being the most relevant and containing the most AM-focused principles to allow electric utilities to realize the value of their asset base through optimal life-cycle management of the assets, from asset acquisition, utilization and maintenance to eventual asset replacement and disposal.

The conceptual model for asset management is illustrated in Figure 3-1 and contains six subject groups and a total of 39 asset management subjects as documented within the Global Forum's Asset Management Landscape, and further detailed in Table 3-1 [3][4]. This conceptual model was utilized to direct METSCO's current-state assessment efforts to specific teams, processes, and tools within AEY.

[3] "Asset Management Landscape: Second Edition", Global Forum on Maintenance & Asset Management, 2014.

[4] "Asset Management – an anatomy – Version 3", The Institute of Asset Management (IAM), 2015.

Table 3-1: Asset Management Landscape Subjects [1]

Landscape Subject Group	Landscape Second Edition Subject
Strategy & Planning	AM Policy
	AM Strategy & Objectives
	Demand Analysis
	Strategic Planning
	Asset Management Planning
AM Decision-Making	Capital Investment Decision-Making
	Operations & Maintenance Decision-Making
	Lifecycle Value Realisation
	Resourcing Strategy
	Shutdowns & Outage Strategy
Lifecycle Delivery	Technical Standards & Legislation
	Asset Creation & Acquisition
	Systems Engineering
	Configuration Management
	Maintenance Delivery
	Reliability Engineering
	Asset Operations
	Resource Management
	Shutdown & Outage Management
	Fault & Incident Response
	Asset Decommissioning & Disposal

Landscape Subject Group	Landscape Second Edition Subject
Asset Information	Asset Information Strategy
	Asset Information Standards
	Asset Information Systems
	Data & Information Management
Organization & People	Procurement & Supply Chain Management
	Asset Management Leadership
	Organizational Structure
	Organizational Culture
	Competence Management
Risk & Review	Risk Assessment & Management
	Contingency Planning & Resilience Analysis
	Sustainable Development
	Management of Change
	Asset Performance & Health Monitoring
	Asset Management System Monitoring
	Management Review, Audit & Assurance
	Asset Costing & Valuation
	Stakeholder Engagement

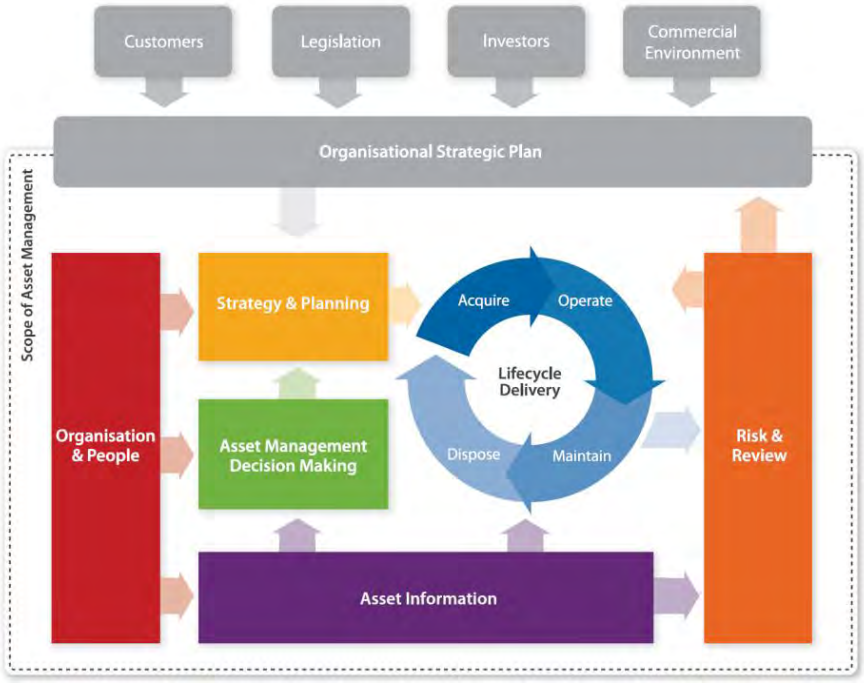


Figure 3-1: Asset Management Conceptual Model [2]

Table 3-2 illustrates the identified business units and operational areas within AEY that interact with the AM practice, as defined by the AM conceptual model illustrated in Figure 3-1:

Table 3-2: Identifying AEY Business Units Interacting with the AM Practice

AEY Business Unit / Operational Area	Landscape Subject Group
Capital Planning	Strategy & Planning
	AM Decision-Making
Maintenance & Operations	Strategy & Planning
	AM Decision-Making
	Lifecycle Delivery
Records Management	Asset Information
Finance & Corporate Reporting	Strategy & Planning
	Risk & Review
Enterprise Risk Management	Organization & People
	Risk & Review

For each of the five areas, AEY leaders were identified to participate in an AM training and workshop in September 2022, followed by a series of detailed interviews, designed to capture key details of their respective functions as they relate to the AM practice. It should be noted that areas of the organization that did not have direct interaction with the AM practice, including human resources, customer care, billing and metering, were excluded from the scope of this assessment.

3.1.2 Comparison with Peer Group & Industry Practices

Leveraging the evaluation framework as described in Section 1.1.1, METSCO categorized AEY's current practices into one of the AM practice maturity levels as specified in Figure 3-2.

These maturity levels were designed to achieve alignment with Global Forum's Guidelines for Assessing Asset Management Maturity [5] as well as the IAM's Maturity Scale for Asset Management [6], while also being right-sized for application within the scope of this assessment. Table 3-3 presents detailed definitions for each maturity level within the assessment.

Figure 3-2: AM Practice Maturity Scale

[5] "Guidelines for Assessing Asset Management Maturity: First Edition", Global Forum on Maintenance & Asset Management, 2021.

[6] "Excellence & Maturity", The Institute of Asset Management (IAM), 2022. URL: www.theIAM.org/Maturity

Table 3-3: AM Practice Maturity Level Definitions

Maturity Level	Maturity Definition
Aware	• Assets are mostly managed reactively, as the organization has not recognized the need for a proactive AM practice. • Data remains limited, and most decisions are driven by subject-matter expertise. • Planning & execution activities are driven mostly by subjective decision-making. • Monitoring/validation capabilities remain limited.
Developing	• Utility has identified the need for an AM practice and has introduced basic forms of analytics, including age-based analysis of assets. • Data is developing but remains siloed across the organization in varying formats. • Planning & execution activities are loosely informed by data and mostly driven by subject-matter expertise. • Monitoring/validation capabilities remain limited.
Developed	• Utility continues to enhance its AM practice, leveraging age and condition-based analytics to drive decision-making. • Data is available from a combination of enterprise systems and stand-alone file formats. • Planning & execution activities are driven by a combination of objective (data-driven) and subjective decision-making. • AM practice is reviewed on annual basis to identify continuous improvements. • Utility is beginning to explore AM industry standards, including ISO 55000.
Enhanced	• Utility is leveraging a combination of age, condition, and risk-based analytics to drive decision-making. • Data is available from a series of enterprise systems but is not necessarily centralized. • Planning & execution activities are mostly driven via objective (data-driven) decision-making, leveraging age, condition, and risk-based analytics. • Formalized monitoring & validation procedures are in place to ensure that the utility can systematically and consistently achieve AM requirements. • Utility is aligning itself to the ISO 55000 AM standard.
Optimal	• Utility is leveraging a combination of age, condition, and economically driven risk-based analytics to drive decision-making and produce justified business cases. • Data is centralized such that all AM decision-making leverages the same consistent information (i.e., "one truth"). • Planning & execution activities are driven via objective (data-driven) decision-making, leveraging age, condition, and economically driven risk-based analytics. • Formalized monitoring & validation procedures are in place to ensure that the utility can systematically and consistently achieve AM requirements. • Utility has fully aligned themselves or is certifying themselves to the ISO 55000 AM standard.

3.1.3 Identifying Opportunities for Improvement

A review of AEY's documentation along with responses from the interviews was used to establish an assessment of AEY's AM practice, as well as establish AEY's maturity level, relative to the maturity scale as presented in Figure 3-2 and Table 3-3.

To perform this assessment, METSCO completed a subjective comparison between the interview responses and results derived from the select peer group, industry standards as well as METSCO's own experience in improving the AM practice for utilities across North America, to identify opportunities for improvement. For each improvement opportunity, METSCO has also established qualitative benefits to the organization.

3.2 Assessment Results

3.2.1 Capital Planning

3.2.1.2 AEY's Current State Capital Planning Practices

AEY's capital planning process consists of the following underlying functions:

- Planning: Development of the capital investment plan and related expenditures.
- Design/Engineering: Development of the underlying discrete capital projects as informed by the capital plan. This includes the project cost estimation, justification as well as the design and engineering considerations.
- Execution: Managing the execution of capital projects in-field, including replacement of assets and reconfiguration of the system, as well as communication and engagement with customers.
- Reporting: Coordinating with Finance to produce the monthly, quarterly, and annual reporting of capital projects, including the tracking of actual expenditures.

Planning

Distribution and generation capital planning were recently combined into a single capital planning process to increase consistency within the planning process across all assets. To establish the capital plan, AEY relies on a set of input data, including:

- Third-Party Reports: External consultants perform engineering studies and/or condition assessments of major assets to recommend and justify asset renewal-related investments.
- Load Forecasting: AEY's load forecasting process forecasts future customer growth within the service area by assessing and studying past customer growth trends. This information is used to recommend and justify capacity-related investments. While this information is normalized with temperature data to establish average growth rates for each of AEY's feeders, this process does not take into consideration emerging technologies, including DERs, EVs and microgrids.
- Load Flow Analysis: AEY leverages CYME – a load flow calculation software – to identify potential capacity, voltage, or configuration issues within the system. CYME is used to evaluate specific contingency scenarios, loading and voltages to recommend and justify asset capacity and reconfiguration-related investments.
- Asset Testing Results: AEY leverages the testing results for individual assets, including cable, pole, and transformer testing results, to identify assets for replacement within the investment plan.
- Technical Studies: AEY leverages results from their load flow analysis as well as their subject-matter expertise to derive technical studies that are used to further justify investment decisions.

- Cost Studies and Business Cases: For major substation equipment, AEY performs financial cost studies for specific scenarios to ascertain the total direct financial impact to the utility should an asset fail within the system.

- Subject-Matter Expertise: For generation assets, external technical consultants and in-house subject matter experts are used to identify and recommend solutions to condition, capacity, reliability, safety, or environmental issues.

The above inputs are collectively leveraged to derive the capital investment plan. Each plan follows a prescribed set of requirements that AEY has identified, such that each plan will be consistent from version to version. A document template guides asset planners through the process of what information must be collected to support the plan and overall justification.

Investments within the plan are organized as a series of projects or are presented in a dedicated spending portfolio. Projects within the capital plan are currently prioritized qualitatively, leveraging AEY's collective subject-matter expertise. Technical studies are performed to drive the prioritization discussions. These distribution studies contain the results of load flow simulations, voltage levels, and qualitative criticality assessments to support the investments. The critical assessments are designed to describe the possible impacts of failure that may occur under a run-to-failure approach.

The capital plan is validated with support from the finance and regulatory groups. Overall expenditures are reviewed and assessed to ensure that spending remains aligned with available resources and system requirements, and to ensure that the resulting rate impacts from these investments remain digestible for customers and aligned to past investments.

Once the plan has been approved internally, it is provided to the Finance group such that they can begin tracking the major capital expenditures. They also begin the process of communicating this plan to the regulatory team, who will be responsible for communicating and justifying this plan with the YUB.

It should be noted that the capital plan is not only limited to physical asset investments but also extends to IT-related investments, including IT systems supporting the AM practice, as well as fleet-related investments, which consider the recommendations from an individually produced fleet management plan.

Design & Engineering

For individual capital projects, detailed designs and cost estimations are produced, leveraging standardized material and labour costs for each type of distribution asset. Cost estimates for generation projects are derived more manually, leveraging the subject-matter expertise of generation planners and designers.

Execution

As capital projects are executed within AEY's service area, capital planning will have regular engagements with finance to assess overall spending levels, to ensure that actual spending is in alignment with the planned spending estimates.

When a project is completed, a close-out process is executed. The nature of this close-out process will vary depending on the size and cost of the given capital project. While all projects go through a close-out, not every project will generate a series of "lessons learned" that can be leveraged for

continuous improvements. AEY has implemented a change control process to account for changes to the budget and schedule for major projects.

Reporting

During and following the development of the capital plan, asset planners work closely with the finance and regulatory teams, who will justify this plan with the YUB.

There are a few metrics used to monitor the effectiveness of the capital plan as projects are executed within AEY's service area, including SAIFI and SAIDI reliability indices.

3.2.1.2 Capital Planning: Comparison to AEY's Peer Group & Industry Practices

The capital planning processes adopted by AEY's peer group generally contain similar underlying functions, including planning, design/engineering, execution, and reporting components. Within the scope of the planning function, AEY's peers leverage similar inputs as part of the planning process, including third-party reports, load forecasting, technical studies, cost studies and business cases as well as subject-matter expertise.

However, this peer group also leverages individual asset analytics, such as asset age and asset health index (AHI) results, to identify system-wide planning needs as well as prioritize individual assets to develop projects.

Historically, utilities introducing such analytics begin with an age-based analysis, in which the assets' current age is compared to its typical useful life (TUL), such that a "remaining life" is determined for each asset, and the backlog of assets already past their TUL are identified. Figure 3-3 illustrates an example of how this analysis is performed across a given distribution system to identify overall system-wide planning needs.

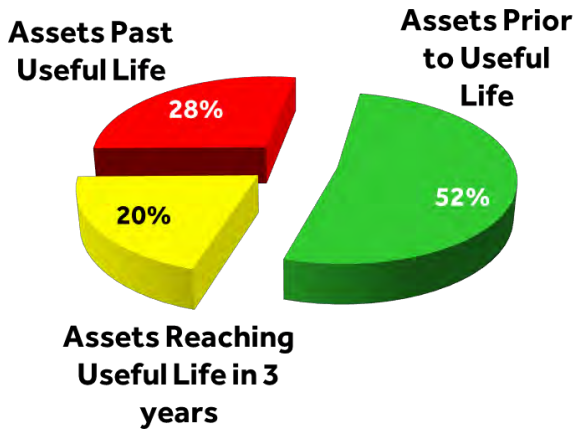


Figure 3-3: Sample Remaining Life Analysis

Currently, AEY leverages raw asset testing results to support the identification and prioritization of assets within distribution projects. However, additional time and effort are spent to analyze and interpret the raw testing results. AEY's peers utilize AHI to convert raw testing results, in addition to visual inspection results and nameplate data, into a consistent condition score. Figure 3-4 illustrates

an AHI framework, whereby subject-matter expertise, asset testing and inspection processes are leveraged to produce and configure the framework. Individual asset testing and inspection results are integrated into degradation factors that are individually weighted following the overall probability of failure of the asset, such that a unique AHI result is produced for each asset.

Figure 3-4: Asset Health Index (AHI) Framework

Table 3-4 illustrates the typical AHI scoring methodology applied by AEY's peers, where the AHI is represented on a scale from 0 (Very Poor) up to 100 (Very Good). As per this approach, it is recommended that assets in 'Very Poor' condition are replaced within the first year, with assets in 'Poor' condition replaced between 1-3 years, and assets in 'Fair' condition replaced between 4-10 years.

Table 3-4: Asset Health Index (AHI) Scoring Methodology

Health Index	Condition	Description	Requirements
85–100	Very Good	Some ageing or minor deterioration of a limited number of components	Normal maintenance
70–85	Good	Significant deterioration of some components	Normal maintenance
50–70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the criticality
30–50	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate considering risk and consequences of failure
0–30	Very Poor	Extensive serious deterioration	Asset has reached its end-of-life; immediately assess risk; replace or refurbish based on assessment

While AEY's peers will leverage a combination of age and condition-based analytics to help prioritize assets for replacement, industry standards such as ISO 5500x further encourage utilities to leverage risk-based results where possible to prioritize assets for replacement.

ISO 5500x further encourages utilities to establish an AM Policy, Strategic Asset Management Plan (SAMP) and Asset Management Plans (AMPs) for individual assets, to establish consistent and well-documented AM processes that can be easily communicated to all stakeholders. The AM Policy allows utilities to link their AM objectives to their corporate values and objectives. AEY's peers have either already developed and integrated an AM Policy, SAMP and/or AMPs into their respective AM practice or are currently developing these documents.

AEY's peers largely rely on reliability metrics, including SAIFI and SAIDI, to measure the effectiveness of their respective AM practice. However, AEY's peers are working towards introducing additional measures that go beyond reliability to assess the overall effectiveness of capital planning and delivery of projects, including the following:

- Cost variances: AEY's peers are focusing on reducing the variances between their original planned cost estimate and actual costs for the capital project. To reduce these variances, AEY's peers are developing enhanced cost estimation procedures, including the use of standardized material and labor costs on a per asset basis.

- Productivity efficiencies: AEY's peers are also touching upon and highlighting improvements to their business processes that introduce productivity efficiencies and savings within the organization.

- Asset performance: AEY's peers are also demonstrating the changes to age, condition, and risk demographics before and after the execution of their capital program. As an example, the results in Figure 3 can be presented before and after the execution of a capital program, to illustrate the reduction of assets already past their useful life.

As illustrated in Figure 5, while AEY does leverage technical reports in addition to their subject-matter expertise to identify and prioritize capital investments, they have yet to apply individual asset analytics that would allow for system-wide planning needs to be identified in a consistent manner. This includes the development of age and condition-based analytics, that leverage in-field inspection data coupled with nameplate information to derive the AHI results. In addition, criticality and risk-based analytics can also be leveraged to better prioritize assets and projects not only based upon the probability, but also the impacts of failure within the system.

By comparison, AEY's peer group does leverage individual asset analytics in combination with other data inputs to prioritize assets for investment consideration. For this reason, AEY's peers fall under the "Developed" category.

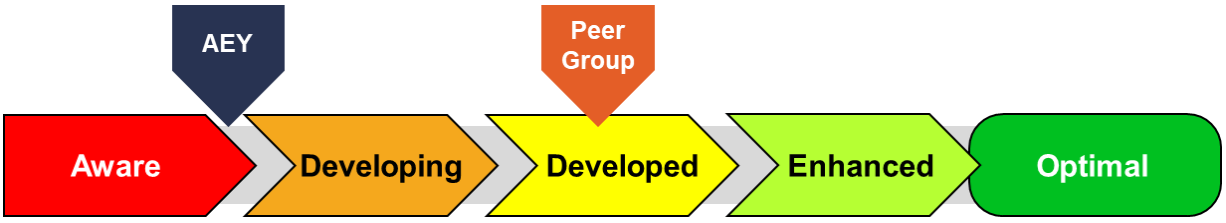


Figure 3-5: Maturity Results for AEY's Capital Planning versus Peer Group

3.2.1.3 Capital Planning: Opportunities for Improvement

Through METSCO's review of AEY's documents, information collected through SME interviews and comparison of AEY to select peers, METSCO has identified key opportunities for AEY to consider as short-term improvements. Developing these key improvement opportunities can support AEY's efforts to improve its asset management functions as well as align itself with utility peers.

I. Introducing an Asset Health Index framework for assets: Traditional asset analytics including age, condition and risk remain undeveloped within AEY. To bring themselves in alignment with their peers, AEY may want to consider collecting age data from the field, while also integrating inspection and testing results into an AHI framework to produce individual asset condition results to support the capital investment plan.
   - Benefits: Leveraging AHI results eliminates the need to manually analyze and interpret raw testing results, thereby introducing cost efficiencies and reducing the reliance on subjective judgements. Age-based analytics also allows AEY to identify system-wide backlogs, thereby justifying the overall need to invest in the system. AHI also represents a strong integration point between OPEX and CAPEX-related processes. Finally, AHI represents a foundational input into the broader development of a risk-based AM framework, where AHI results can be leveraged in conjunction with asset criticality results to derive a risk matrix.

II. Expanding AEY's Asset Management Vision and developing an Enterprise-wide Asset Management Policy, Strategic Asset Management Plan and developing specific Asset Management Plans for Major Asset Classes: AEY's capital planning process is not formally documented, along with AM objectives, strategies, and investment approaches for individual asset classes. To bring themselves in closer alignment with their peers, AEY may consider introducing formal documentation, including an AM Policy, SAMP, and AMPs for each asset class.
   - Benefits: Formal documentation ensures that the AM practice is applied consistently, and those new employees can easily learn about the underlying procedures and methodologies. The AM Policy also allows AEY to align their AM objectives with organizational objectives. Furthermore, documentation can introduce efficiencies with GRA audits or justifications for investment projects.

III. Developing a Capital Investment and O&M spending portfolio optimization decision support strategy and process: Currently, investments within AEY's capital plan are prioritized by leveraging subject-matter expertise as well as technical reports and sequenced based on capital and resource limitations. With this approach, AEY's SMEs may not be aware of every known or unknown issue and may interfere with the prioritization of investments. In addition, non-

prioritized and deferred maintenance results in operational risks that may or may not be managed appropriately, plus has an unknown impact on the lifecycle cost and reliability of assets. AEY may want to consider leveraging asset analytics, as well as corporate values and objectives, to prioritize and schedule their investments.

- Benefits: Leveraging asset analytics to prioritize investments against corporate values or performance objectives will result in cost efficiencies being introduced, by reducing or eliminating the need to leverage subject-matter expertise and ensure investment funds are being spent in the right focus areas for the organization to succeed proactively rather than reactively. Thus, AEY's capital planning approach will shift from "SME-Driven Planning" to "Qualitative Planning".

IV. Refining Performance Management Framework and Develop Asset Management Controls, Dashboards, and Reports: AEY currently leverages SAIFI and SAIDI to monitor the effectiveness of their investments. To further improve validation procedures, AEY is encouraged to introduce additional KPIs to better track the overall effectiveness of the plan as it relates to spending, system reliability and data accuracy.

- Benefits: Strong review and validation procedures allow for utilities to continually improve upon their AM practice and associated investments. External regulatory bodies track a variety of metrics that extend past the traditional SAIFI and SAIDI metrics – these include asset health metrics, capital and maintenance spending (planned vs actual), customer engagement, and financial metrics. Currently, it is uncertain when the YUB will adopt modern approaches like neighbouring provinces and territories such as British Columbia or Alberta, but it is a plausible outcome for the YUB to introduce and adopt them eventually. However, performance measures are not only meant as a reporting function to the YUB. Performance metrics provide benefits for internal teams to continuously monitor and improve their asset management function.

3.2.2 Maintenance & Operations

3.2.2.1 AEY's Current State Maintenance & Operations Practices

AEY's maintenance and operations consist of the following functions to manage the planning and execution of maintenance and outage response procedures for substation, distribution and generation assets:

- Visual Inspections: Execution of targeted visual inspection procedures for major distribution and generation asset classes.
- Line Patrols: Execution of a summarized visual inspection procedure designed to identify and report on specific defects within the system.
- Asset Testing: Coordination with third-party entities to perform testing procedures for substation, distribution and generating assets. Note that while fluid testing is performed for engines, there is no additional procedures to analyze these results to further integrate these into the planning process.
- Vegetation Management: Execution of tree trimming to maintain clearances between the distribution lines and surrounding environments.

- System Operations: Management and monitoring of the system, including outage response and recording, as well as execution of planned outages and isolation procedures to support planned capital and maintenance activities.

- Fleet Asset Management: Management of the utilities' fleet-related assets, including vehicles and bucket trucks.

- Meter Reading: Management of the meter reading process to capture accurate reads from the customers' meter base.

- Basic Operations: Management of system locates, disconnects, and supervised excavations.

- Generation Repairs and Overhauls: Execution of major repairs and overhauls to generation equipment.

- Generation Operations: Management and monitoring of generation assets, including outage and start-up procedures, capacity and contingency management to support planned and maintenance activities requiring isolation, testing of protections and control devices, along with SME inspections for regulated and higher-value equipment (i.e. tanks, engines, generators, vessels).

Substation & Distribution Maintenance

AEY's substation and distribution maintenance activities include line patrols, visual inspections, repairs and overhauls as well as testing activities.

Line patrols represent the primary method that AEY applies to establish an initial "scan" of their asset base, and to identify where more in-depth visual inspection or testing procedures must be executed. From the line patrols, inspectors may identify assets that are close to end-of-life and must be immediately replaced. An example of this would be AEY's "Danger Pole" program, in which poles identified as being at end-of-life are integrated into an investment portfolio, which is then integrated into the capital plan. This represents one important touchpoint between the OPEX and CAPEX processes. AEY's Distribution Interruption Reporting (DIR) database, which contains all historical outage events, is leveraged to prioritize line patrols.

Visual inspections involve the recording of in-depth details from the inspection process and will vary depending on the asset class being inspected. Currently, all visual inspection results are recorded in paper format, and this is later scanned electronically. Results from visual inspections are not directly used to support the three-year capital plan, although insights from these inspections may be used in supporting the discussions between subject-matter experts when projects are prioritized within the plan.

Testing involves the execution of a defined technical process to assess the condition of the asset, with a quantifiable result typically produced. These testing procedures may be performed by AEY or by a third-party company, depending on the nature of the test.

Vegetation management involves the trimming of adjacent vegetation to the distribution lines to mitigate any clearance issues and potential risk of tree contact. As is the case with line patrols, data from the DIR is used to support the prioritization of vegetation management activities.

There is a documented competency training program that is delivered via a third-party organization, designed to provide training on the maintenance processes and actions to each inspector. The training program is designed such that each inspector is executing the same consistent procedures for visual inspection, vegetation management and testing. Every three years, an audit is performed for each inspector to re-assess their skillsets and their understanding of the maintenance procedures. Furthermore, this process is also applied to third-party contractors performing testing activities, to ensure that their testing procedures are in alignment with AEY's requirements.

Where AEY does not have the internal skill sets, maintenance activities will be outsourced for execution by third parties. At the same time, certain activities, including line patrols, must be performed by the utility, and cannot be outsourced.

Specific substation and distribution maintenance activities will undergo continuous improvements based on underlying data. For instance, DIR data is leveraged to reprioritize and enhance vegetation management activities. However, there is no formal process executed to continuously enhance and improve all maintenance activities over time.

Total operating and maintenance expenditures are balanced with trends from prior years to ensure that the total budget remains consistent. However, AEY does not currently leverage system performance measures such as SAIFI and SAIDI to assess whether maintenance expenditures should be increased or decreased for future years.

Generation Maintenance

Maintenance expenditures associated with engine overhauls are captured within *Engine Overhaul Tracking Sheets*, with *Plant Deficiency Lists* containing a backlog of work orders that must be performed throughout the year. Major equipment overhauls are planned based upon average run hours over a five-year history, and work is juggled to fit within seasonal or budgetary constraints.

Visual and functional inspections are conducted at generation sites by SME's on a regular basis. Results from these inspections are leveraged to identify new capital investments that include major replacement and/or repair activities. Any work deemed to be "non-critical" will be integrated into deficiency tracking sheets, establishing a backlog of investments that will be deferred.

Testing of critical devices is conducted according to OEM manuals and recorded on internal check sheets. Results are reviewed by maintenance personnel for comparison to prior trends and established guidelines, then repairs or replacements are scheduled according to priority.

There are no formal competency programs for generation maintenance activities. However, for new employees and contractors, procedure training and job observations are performed to ensure that maintenance activities are performed in a consistent manner. Overhauls (engines, generators, turbines) are outsourced to qualified third parties.

At the end of each month, a generation month-end report is manually produced to reveal diesel fuel quantities and engine hours. Finance and regulatory and planning departments use this information in addition to SCADA derived equipment histories. In general, the identification, scoping, prioritizing and planning for generation maintenance activities, including preventative and corrective maintenance, remains ad-hoc in nature.

System Operations

AEY's operational processes include outage response and restoration, outage data recording and planned outages to support planned activities, including planned capital and maintenance activities.

Distribution outage data, including the cause of the outage, duration, location and scope of the outage are collectively recorded within the DIR system. AEY has been capturing the nomenclature of the failed asset(s) that led to the outage in question. While all outages are entered into the DIR system, only those outages that impact 50 or more customers are regularly reviewed and validated, including the outage cause, duration, and location. This same data is also used as part of regulatory reporting to the YUB. AEY performs validation procedures as part of efforts to improve overall outage data accuracy.

DIR data is indirectly used to support the development and prioritization of capital projects, through discussions between the asset planners and subject-matter experts.

Data from AEY's SCADA system is updated every 15 minutes and captured by a data historian. This information can be used to help support maintenance operations. For example, outage information as captured from the SCADA system can be used to modify the maintenance activities as part of continuous improvements.

3.2.2.2 Maintenance & Operations: Comparison to AEY's Peer Group & Industry Practices

AEY's utility peers generally apply the same maintenance functions, including visual inspections and line patrols, asset testing, repairs and overhauls.

While some information may still be captured on paper, AEY's peer group is transitioning to electronic data entry, with visual inspection and testing results entered either on a laptop or mobile device. These results then integrate into an AHI framework.

Industry practices such as Reliability Centered Maintenance (RCM) allow utilities to better optimize the specific tasks, frequencies, and actions within each maintenance program. The RCM framework, as illustrated in Figure 3-6, is designed to break down each asset class into specific asset components, and define functional statements, failures, and failure modes for each component. Corrective actions can then be identified to mitigate each potential failure mode, which can then be incorporated into the maintenance program. This systematic approach allows for risk and criticality attributes to be integrated into failures scenarios, to help determine priority of the corrective actions identified.

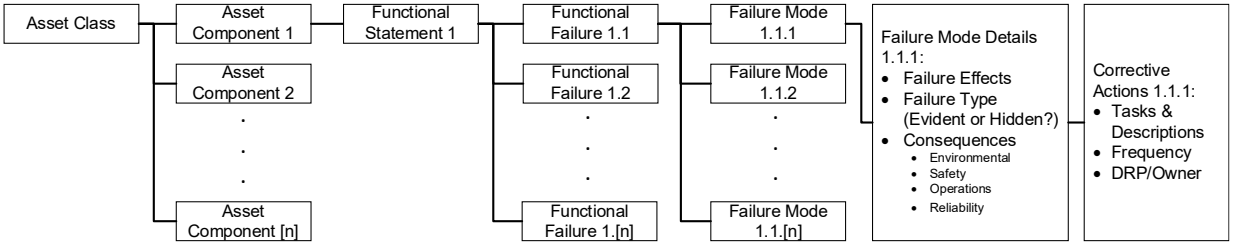


Figure 3-6: RCM Framework

Leading industry practices also recommend that utilities establish strong documentation for maintenance programs, including maintenance manuals that clearly describe the program, the tasks, and the cycles. While maintenance manuals are not a consistent practice adopted by AEY's peer group, it is a practice that more and more utilities are transitioning to.

AEY's peer group has adopted formalized systems, including Computerized Maintenance Management Systems (CMMS), to inventory assets and planned work, store collected maintenance data, and manage maintenance activities / records as they are executed within the system. These systems greatly enhance the integration of inspection and testing results into an AHI framework.

AEY's peer group generally applies the same operational processes, including outage response and restoration, outage data recording and planned outages to support planned activities, including planned capital and maintenance activities. Outage data is traditionally stored in an OMS system, like the DIR system currently adopted AEY. Notably, AEY collects asset nomenclature information as part of the outage recording procedure – something that is not typically performed by AEY's peer group. Having asset nomenclature appended to the outage record allows for additional analytics to be generated from the outage data, including the derivation of failure curves to predict future failures within the system.

As illustrated in Figure 3-7, when compared to the peer group and industry practices, AEY's maintenance and operations practice falls under the "Developing" category on the AM practice maturity scale. While AEY does generally apply the same operational and maintenance procedures as their peers, they have yet to transition to formalized CMMS platforms to manage and optimize their maintenance activities and have yet to consider formalized maintenance standards. By comparison, AEY's peer group would fall under the "Developed" category, as they have shifted towards CMMS platforms and are actively integrating the outputs from their maintenance activities into ACA frameworks to support capital and maintenance planning.

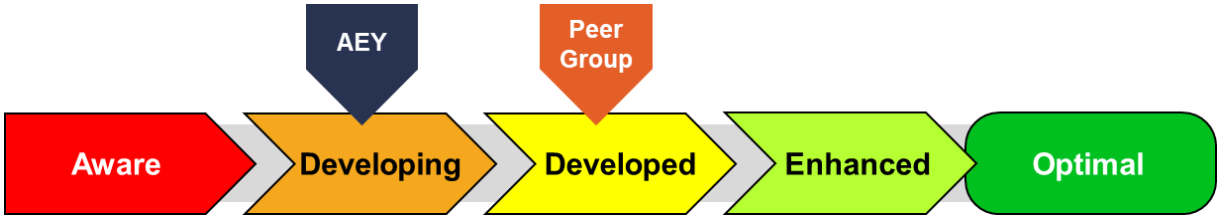


Figure 3-7**: Maturity Results for AEY's** Maintenance & Operations versus Peer Group

3.2.2.3 Maintenance & Operations: Opportunities for Improvement

Through METSCO's review of AEY's documents, information collected through SME interviews and comparison of AEY to select peers, METSCO has identified key opportunities for AEY to consider as short-term improvements. Developing these key improvement opportunities can support AEY's efforts to improve its asset management functions as well as align itself with utility peers.

I. Assessing and Enhancing Knowledge and Competencies: While AEY does have a documented Competency Training program in place to provide full training on the distribution maintenance processes, the utility may also want to document all maintenance procedures – including objectives, tasks, and frequencies – within a maintenance manual. Also, create this documented structure for the generation maintenance program.
    - Benefits: Documentation for maintenance programs allows for the associated tasks and activities to be performed consistently. Documentation also allows new employees to easily become accustomed to the maintenance procedures, which can reduce overall operating costs within the organization. Also, contracting out can be an option if internal resources are unavailable (i.e. due to staffing shortages).

3.2.3 Records Management

3.2.3.2 AEY's Current State Records Management Practices

AEY's records management function consists of the management of as-built data for distribution assets into their *MicroStation* CAD system, which represents their system of record for spatial asset registry data.

Changes made to distribution asset infrastructure will be reflected within *MicroStation* via the entry of as-built data, which is provided through the capital planning group, as capital projects are executed within the system. Information stored within *MicroStation*, including asset registry and age data, is then provided to capital planning for each asset class. These collectively represent an "asset database". Key information found within these files includes:

- Asset nomenclature/identifier
- Primary/secondary voltage information
- Location/address information
- Associated asset nomenclature (e.g., associated pole to an overhead transformer or switch)
- Manufacturer/serial number information
- Year of manufacturer
- Associated project number
- Asset class-specific information
    - Transformers: size, PCB quantity, etc.
    - Poles: height, class
    - Switches: equipment type

It should also be noted that the above data is only populated for those assets recently digitized within *MicroStation* via the as-built process. This data is only available for capital projects that have been completed over the past 10 years. In general, this data remains highly decentralized, and there are no documented procedures on how this information should be managed or updated over time. It should also be noted that there are limited documented procedures or controls in place for managing engineering drawings, isolation diagrams or equipment manuals. For generation assets, there are also no as-built libraries or document controls in place.

The lack of data centralization and controls means that more time must be spent manually collecting and validating information to support the development of the capital plan. As this lack of centralization extends to as-built engineering drawings and equipment manuals, this can also pose operational risks when managing outage events.

3.2.3.2 Records Management: Comparison to AEY's Peer Group & Industry Practices

AEY's utility peers have similar systems of record to store asset registry and spatial data, including the data attributes as described in Section 2.2.3.1. However, these utilities were found to have more information readily available across their asset base, including age information, that can be useful to support capital planning and development of the capital investment plan.

AEY's peer group was also found to have a mix of centralized and decentralized information used to support the AM practice. Centralized data is often easier to access, extract and utilize to prioritize assets and generate capital projects. Data centralization also helps establish a "single source of truth", meaning that all stakeholders are leveraging the same common information to support AM

decision-making. Centralized data also greatly reduces the amount of effort and time to access the information, thus introducing cost efficiencies within the utility.

As part of efforts to better align to leading industry practices, utilities are transitioning from decentralized to centralized data, by incorporating all decision-making data into accessible systems-of-record, such as Geographical Information Systems (GIS), Enterprise Resource Planning (ERP) and CMMS platforms, thereby enabling cost efficiencies. As part of these efforts, utilities are establishing data structures for their capital and maintenance planning procedures, which consist of all necessary input information needed to support prudent decision-making.

In tandem with data centralization and application of enterprise systems, AEY's peers were also found to have documented policies and controls concerning the management of data, including operational documents such as engineering drawings and equipment manuals.

As illustrated in Figure 3-8, when compared to the peer group and industry practices, AEY's records management falls under the "Aware" category on the AM practice maturity scale, due to the lack of centralized data, documentation and controls, as well as lack of available data for existing assets that were installed before the introduction of *Microstation*. By comparison, AEY's peer group would fall under the "Developed" category, as they have shifted towards GIS platforms and data centralization practices, as well as introducing programs to enhance data quality over time.

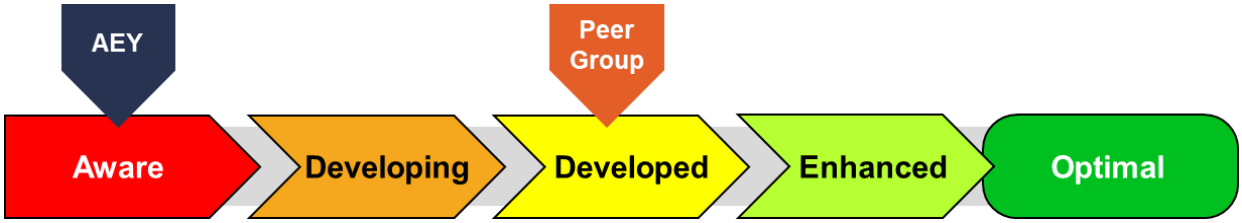


Figure 3-8: Maturity Results for AEY's Records Management versus Peer Group

3.2.3.3 Records Management: Opportunities for Improvement

Through METSCO's review of AEY's documents, information collected through SME interviews and comparison of AEY to select peers, METSCO has identified key opportunities for AEY to consider as short-term improvements. Developing these key improvement opportunities can support AEY's efforts to improve its asset management functions as well as align itself with utility peers.

I. Implementing a centralized Enterprise Asset Management Strategy: AEY's decision-making data is largely decentralized and must be manually collected by subject-matter experts to support the AM practice. AEY may want to consider shifting to a centralized data model, where all data is stored within a single system of record. This will include assessing what data is currently available, creating a data structure that associates specific data inputs to each process within the AM practice, and establishing an implementation roadmap that prioritizes the most critical data to be centralized first.
    - Benefits: Centralized data is easier to extract, access and integrate into a broader AM system, thereby introducing efficiencies and enhancing overall accuracy of results. Targeted benefits will include:
        - Enhanced Maintenance Data: The Enterprise AM strategy will establish clear processes for how in-field maintenance data is collected and how it can be integrated into a CMMS.
        - Enhanced Financial and Corporate Reporting: The Enterprise AM strategy will also help define how bottom-up AM data can be leveraged to support financial and

corporate reporting procedures as well as integrations to an Enterprise Resource Planning (ERP) system.

- Enhanced Geospatial Data: The Enterprise AM strategy will help define how geospatial and connectivity data within a GIS will be managed and updated as projects are constructed, and as-built drawings are defined.
- Enhanced Document Control: The Enterprise AM strategy can define specific policies for management of operational and engineering documents as part of a broader Engineering Document Management System (EDMS)

II. Enhancing the collection, storage, maintenance, accuracy, completeness, and use of data: Currently, age information is only available for newly installed assets. As part of efforts to centralize their data, AEY may want to consider data quality improvement efforts, whereby missing age and other asset registry data, such as nomenclature, nameplate, location and rating information are retrieved from the field and entered into the system of record.
    - Benefits: Ensuring that all assets have available age and asset registry details allow AEY to transition away from SME-driven planning and towards a more qualitative planning approach, whereby accessible asset data is directly influencing the capital and maintenance investment plans. Capturing this information proactively for all assets can also introduce cost efficiencies within AEY, as opposed to capturing this information reactively when projects are identified.

3.2.4 Finance & Corporate Reporting

3.2.4.1 AEY's Current State Finance & Corporate Reporting Practices

AEY coordinates with ATCO's finance and corporate reporting group to track CAPEX and OPEX expenditures and manage these expenditures for internal and external purposes.

Internally within AEY, an accounts payable team manages the day-to-day financial operations, including:

- Processing and payment of invoices,
- Payment for new assets,
- Ensuring that newly installed assets are capitalized, and,
- Ensuring that the overall asset value is accurate when accounting for recently retired and salvaged assets.

ATCO's finance and corporate reporting group, which is based out of Edmonton, Alberta, interacts regularly with AEY's capital planning group to perform the following:

- Asset Capitalization: Information regarding a given capital project is provided to ATCO's finance group such that the newly installed assets are properly and accurately capitalized.

- Asset Retirement: Assets that are removed/retired from the system are also communicated to ATCO's finance group such that they can be accurately retired from the system.

- Work in Progress (WIP): Each quarter, a review is performed on capital work-in-progress to ensure that assets are being capitalized at the correct time.

- Key Performance Indicators (KPI): ATCO's finance group will leverage the data shared by AEY to report on asset capitalization, retirement and WIP as part of their corporate KPIs.

In addition, ATCO's finance group provides support to AEY's capital planning function when developing the capital plan. For instance, ATCO's finance group will help validate overall spending amounts within the capital plan by providing historical spending trends. They will also work with ATCO's regulatory team – also based out of Edmonton – to establish the necessary justification to support the plan to the YUB as part of regulatory reporting procedures. For instance, ATCO's finance group will ask questions to AEY's capital planning representatives regarding specific projects within the plan. ATCO's regulatory team provides the capital planning team with business case reporting expectations for individual projects. ATCO's financial group also performs a similar validation of AEY's operations and maintenance expenditures. It should be noted, however, that there is currently no assessment performed on resourcing constraints, project prioritization or whether the budgeted capital projects align with organizational objectives.

Variance analysis, or the comparison between planned expenditures and actual expenditures – is another key output from ATCO's finance group. Where variances are identified and quantified, ATCO's finance group will gather the necessary information on the drivers of the variance, and how the variance will impact future funding cycles. It should be noted that the variance analysis remains reactive – the review of these variances only occurs after they have already emerged. In addition, there are no defined guidelines for establishing the initial business case and ensuring cost estimation accuracy. Therefore, there remains a gap with respect to overall accountability of the planned cost estimate.

In parallel, however, AEY will hold monthly meetings to review the status of major projects and report on potential delays that could lead to variances in the future. While variance analysis could be performed monthly, it is only performed for major projects. AEY and ATCO are currently attempting to shift this process to a monthly cycle, due to corporate policy.

It should be noted that there is no documented process defined for the interactions between ATCO's finance and corporate Reporting and AEY's capital planning and maintenance and operations groups and ATCO's regulatory team. All financial data is stored and managed within ATCO's Oracle ERP system.

Even though ATCO's finance group operates out of a different location from AEY, the overall interaction between these two groups remains strong, and recent advancements in teleconferencing technologies have allowed for communications to remain dynamic such that issues continue to be proactively identified and appropriately managed. However, there are certain elements within the finance and regulatory processes, including inputs for the business case (e.g. discount rates, cost of capital, depreciation and rate base, inflation rates, etc.) that are not directly shared with asset planners such that these can be more optimally defined within the capital planning process.

3.2.4.2 Finance & Corporate Reporting: Comparison to AEY's Peer Group & Industry Practices

AEY's utility peers have similar finance and corporate reporting functions, including accounts payable, as well as asset capitalization, retirement and WIP functions.

AEY's peers have similar variance and regulatory reporting functions within their respective organizations. When compared to the peer group, AEY's current finance and corporate reporting procedures are quite extensive and ensure that the utility is accurately capitalizing and retiring its assets on time. AEY's current practice of validating variances monthly is more frequent than the annual reporting typically performed by peer utilities. At the same time, there are opportunities for improvement, both for AEY as well as the peer group. Within the context of the finance and corporate

reporting procedures, AEY's peers have yet to establish comprehensive processes that directly align capital projects with organizational objectives to support prioritization.

For these reasons, as illustrated in Figure 3-9, AEY's finance and corporate reporting falls under the "Developed" category on the AM practice maturity scale, which aligns with their peer group.

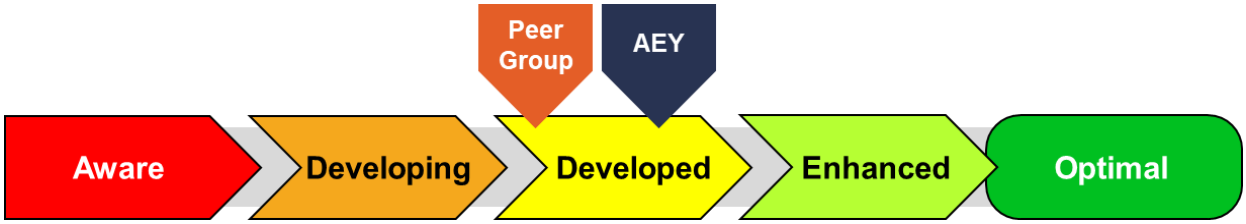


Figure 3-9**: Maturity Results for AEY's Finance & Corporate Reporting versus Peer Group**

3.2.4.3 Finance & Corporate Reporting: Opportunities for Improvement

When accounting for the maturity results associated with finance and corporate reporting, there were no immediate/short-term opportunities for improvement were identified. However, through METSCO's review of AEY's documents, information collected through SME interviews and comparison of AEY to select peers, METSCO has identified key opportunities for AEY to consider as long-term improvements. These are further described in Section 4.2.4.

3.2.5 Enterprise Risk Management

3.2.5.2 **AEY's Current State ERM Practices**

While AEY does not have a formalized ERM practice, they do have several underlying processes designed to manage the broader risks across the organization. This includes the following functions:

- Organizational culture, strategy and values
- Supply chain and inventory management
- Critical spares management
- Grid resiliency and climate adaptation
- IT/OT enablement
- Regulatory risk management
- Management of change

Some of these functions are managed locally within AEY, while others are managed via the parent ATCO organization.

For example, AEY relies on support from ATCO to bring qualified staff into the organization. ATCO has a dedicated training and development group that provides AEY with the necessary training programs to facilitate knowledge transfer to newly hired linemen. AEY does coordinate with ATCO to drive continuous improvements to these training programs. However, internally within AEY, knowledge remains with key SMEs, and there is no dedicated knowledge transfer system.

AEY does not have a dedicated supply chain and inventory management function to manage the procurement of new assets as well as the management of critical spares. AEY's warehouse and inventory are managed by trades for distribution-related equipment and projects only. Generation

spares and inventory are managed by trades and technicians which are not centralized or controlled by AEY directly, and the equipment in inventory is ad hoc.

Generation projects have their parts and materials managed by project managers, who leverage AEY's financial clerks to establish requisitions for ATCO supply chain buyers. These buyers, in turn, will prepare competitive tenders or award purchase orders leveraging ATCO's procedures and policies. Recently, a PowerApps database has been created to inventory common on-hand maintenance parts for generation assets. AEY works closely with ATCO and their systems to manage supply chain procedures. As an example, AEY leverages ATCO's Oracle procurement system to optimize asset inventories. This system is also used to optimize the management of critical spares as per a 5-year rotation plan. AEY is in the process of transitioning to ATCO's critical spares procedure, to improve the management and optimization of critical distribution spares.

AEY is undertaking studies with Yukon University to better manage critical risks that can impact grid resiliency. This includes recent studies such as assessing the impact that electric vehicle adoption could have on the grid and associated assets, assessing the rooftop solar impacts, and introducing electronic metering and automation into AEY.

AEY does not have a local IT function, designed to provide support for the integration and acquisition of new software to support planning and operational processes. AEY does rely on ATCO to bring in new software that has already been implemented within the parent organization, or AEY's planning or operational groups will implement new software solutions directly.

AEY manages project risk through its capital planning process for distribution projects only. However, the operational risk matrix was inherited from ATCO which may have been a strategic cost-saving approach, but it may not be right-sized for AEY's operations and business size. Furthermore, a project risk process does not exist for generation projects. For example, there is no documentation of contingency plans for the provision of power if any critical piece of equipment were to fail or no documentation of switching orders. These documents are vital pieces to manage risks that can occur on a project.

Furthermore, AEY does not have a localized program to manage enterprise risks, such as regulatory risks within the organization. Rather, these risks will be managed indirectly through the other functions within AEY, including:

- Capital Planning: Management of reliability and regulatory risks
- Maintenance and Operations: Management of operational, safety and reliability risks
- Records Management: Management of data quality risks
- Finance and Corporate Reporting: Management of financial and regulatory risks

3.2.5.2 ERM: Comparison to AEY's Peer Group & Industry Practices

AEY's utility peers have similar and closely aligned ERM processes and functions. However, a key difference is that these processes and functions are local to each utility, as opposed to AEY, where many of these functions are managed by the parent ATCO organization.

For example, AEY's utility peers were found to have dedicated organizational strategies, training and development programs, and IT departments to manage the procurement and integration of new software.

Having a localized organizational strategy has allowed AEY's peers to define strategic pillars, objectives and underlying initiatives that are fully compatible with their service area, asset base, resources and constraints that may be faced. Similarly, localized training and development programs can account for the unique processes and challenges faced within the utilities' service area. By comparison, AEY's current-state processes designed to develop their organizational structure may be inadequate for establishing the broader structure and resources that will be required to fully implement an AM system.

Dedicated IT departments can work closely with the utility function groups to solve operational challenges and select "right-sized" software that fits with the culture, processes and end users who will be interacting with the software on a day-to-day basis.

AEY's peers also have or are developing programs to manage enterprise-level risks in a direct and centralized manner, including reliability, operational, regulatory, IT-related, climate change, renewables, and financial risks.

As illustrated in Figure 3-10, when compared to the peer group and industry practices, AEY's ERM practices fall under the "Aware" category on the AM practice maturity scale, due to the most manual nature of how ERM-related processes interface within the organization. As there is no direct management of enterprise risks within AEY, and as many ERM-related elements are managed through the parent ATCO entity, it is up to the AEY SMEs to ensure that these processes are being leveraged locally to manage risks and challenges. By comparison, AEY's peers would fall between the "Developing" and "Developed" categories, as they are either introducing or have introduced formalized ERM practices, including "right-sized" organizational strategies, asset risk analyses and enhanced policies to manage critical spares.

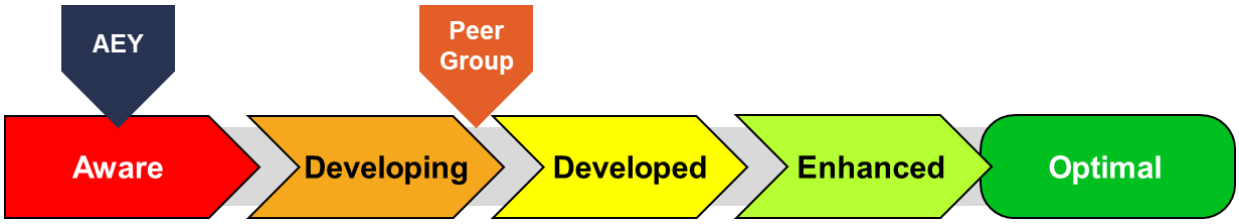


Figure 3-10**: Maturity Results for AEY's ERM versus Peer Group**

3.2.5.3 ERM: Opportunities for Improvement

Through METSCO's review of AEY's documents, information collected through SME interviews and comparison of AEY to select peers, METSCO has identified key opportunities for AEY to consider as short-term improvements. Developing these key improvement opportunities can support AEY's efforts to improve its asset management functions as well as align itself with utility peers.

I. Clarifying the approach to Critical Spares management: AEY has noted that they are in the process of transitioning to a critical spare procedure as established by ATCO for distribution assets. As part of the implementation, contingency plans should be developed to account for critical assets, as well as emergency outage scenarios. AEY should consider fully implementing the critical spares procedure, to manage the risks within their system. Following implementation, AEY should monitor this procedure and be prepared to introduce enhancements to account for localized challenges that may be faced.

- Benefits: A critical spares procedure is necessary to ensure that loss of supply and contingency risks are optimally managed within AEY's system.

II. Defining the Scope of the Asset Management System, revisiting and refining (as necessary) the overall Asset Management roles across the organization and right-sizing the Asset Management function: While ATCO has in the past produced some elements of a strategy for AEY, these elements may not account for the localized challenges and risks that exist today within AEY's service area, as well as the specific organizational structure, hierarchy and resources necessary to support the AM function. AEY should consider developing a localized business plan that aligns with its organizational objectives, resources and hierarchy while establishing AEY-specific pillars, objectives and initiatives that are "right-sized" to the organization and service area within asset management.
    - Benefits: Leveraging a "right-sized" organizational strategy that is fully compatible with AEY results in strategic pillars, objectives and initiatives that can be operationalized at the lowest cost while managing localized risks. Drives the creation of a culture to meet local performance needs.

4 Roadmap & Opportunities for Improvement

4.1 Methodology

As stated earlier, the above-summarized initiatives address enhancement opportunities relative to the ISO55001 standard, acceptance and execution of which will lay the foundation for "developed" maturity. However, in acknowledging AEY's primary responsibility to deliver safe and reliable service to its customers (i.e., not ISO550001 certified service), and at a reasonable cost, we have structured a phased roadmap to center on those opportunities that we deem advantageous to the launching of an enhanced Asset Management process, scaled to fit the financial and resource realities of AEY. Though all enhancement opportunities are viewed by METSCO as worthwhile, some are deemed as more urgent, though of significant importance, and cannot be properly scoped until the initial elements of an Asset Management system are fully operational.

Leveraging the results as produced in Section 3.2, a roadmap was developed to optimize the delivery of the enhanced AM practice, such that the rollout is digestible, achievable and "right-sized" for AEY. Figure 4-1 illustrates a proposed approach that balances the overall achievability and "right-sized" nature of the plan with the overall priorities within the utility.

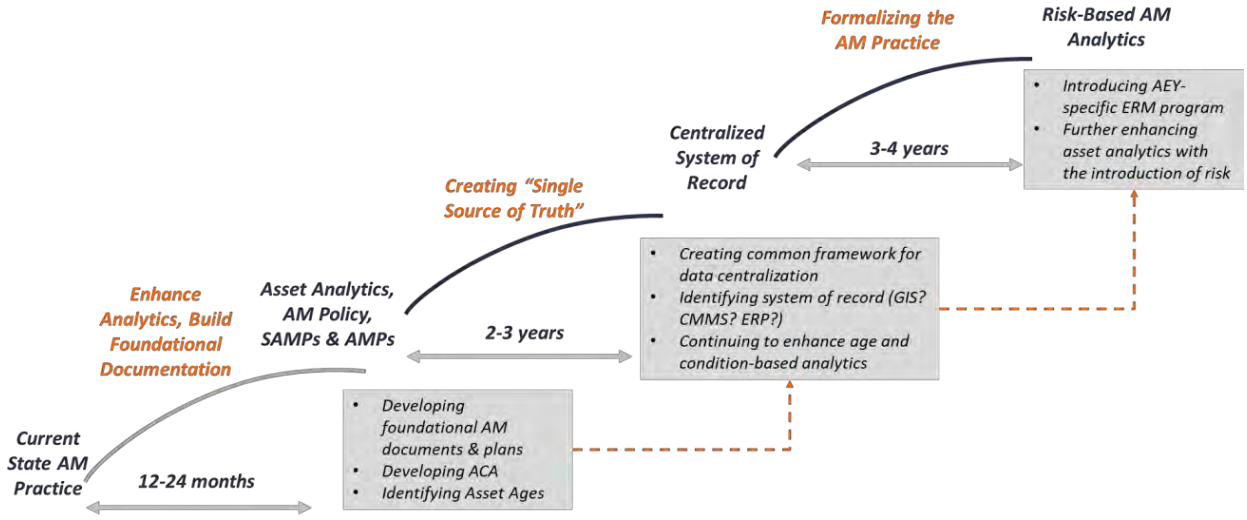


Figure 4-1: Proposed Roadmap Framework for Implementation of Improvement Opportunities

This roadmap proposes to split the improvement opportunities into three priorities, which are further described below:

- Priority 1: Introducing Foundational Analytics and Documentation. These initiatives will provide the necessary foundations to support broader improvements in subsequent stages.
- Priority 2: Centralize Data into a System of Record. These initiatives will ultimately allow for data to be centralized and fully accessible to support AM activities.
- Priority 3: Risk-Based AM Analytics. These initiatives will include the introduction of risk-based AM planning as well as Enterprise Risk Management (ERM) activities to manage corporate-level risks.

4.2 Roadmap & Recommendations

METSCO has established a broader priority for short-term and long-term recommendations, that have can be distributed for a 5-year plan. AEY has already begun its AM roadmap with the delivery of this report and project scope, which included AM training, the assessment of AEY's AM practice, as well as the development of this priority list.

Each recommendation within the roadmap has been prioritized based on the following factors:

- The relative importance and criticality of implementing the recommendation within the organization,
- Projected benefits achieved from implementing the recommendation,
- Available resources within AEY who will be responsible for implementing the recommendation, and,
- Alignment to the priorities and associated milestones.

Tables 4-2 and 4-3 outline the recommendations by priority for the AM practice. To assist in this assessment of recommendations, Table 4-1 provides brief descriptions of information to consider for each recommendation, to implement a corresponding initiative and apply the following execution criteria of cost and level of effort with resource considerations. Figure 4-2 presents a suggested order of operations to execute the identified recommendations.

Table 4-1: Execution criteria

Category	Cost	Level of Effort
Low	Less than $100,000.	Can largely be done with internal resources with the support of external review.
Medium	Between $100,000 and $250,000.	Likely to require resources that have the internal capacity or knowledge base with the support of external guidance.
High	$250,000+	Substantial challenges with an implementation that will require dedicated project management and external facilitation.

Table 4-2: AM Practice Priority 1

Priority 1		
ID	Project/Recommendation	Description
1	Introducing an Asset Health Index framework for assets	Introducing a framework that leverages age, inspection and testing results to produce an asset health index (AHI) for each individual asset. The framework, which is expected to take 4 months to develop, can be applied to AEY's current-state data. As AEY's data continues to improve and evolve via other initiatives (e.g. Projects 6 & 7), the AHI sample size will expand and accuracy of results will improve. AEY Execution Requirements Timetable: 4 months Level of Effort: Medium Cost: Low Capital: Possible if housed in a software

		Note: this project initiative is further documented in Appendix A.
2	Expanding AEY's Asset Management Vision and developing an Asset Management Policy and Strategic Asset Management Plan	Developing foundational asset management documents, including the AM Policy, which aligns AM objectives with organizational objectives, and the Strategic Asset Management Plan (SAMP), which documents the relationship between organizational and AM objectives, while also defining the framework required for AEY to achieve their AM objectives. AEY Execution Requirements Timetable: 8 months Level of Effort: Medium Cost: Low Capital: Unlikely *Note: this project initiative is further documented in Appendix A.* *Note: Appendix B contains a guideline for AM Policy and SAMP.*
3	Developing specific Asset Management Plans for Major Asset Classes and refining performance management framework	Developing Asset Management Plans (AMPs) for individual asset classes, along with additional KPIs to track the effectiveness of the AMPs as it relates to spending, reliability, and data accuracy. AEY Execution Requirements Timetable: 8 months Level of Effort: Medium Cost: Low Capital: Unlikely *Note: Appendix B contains a guideline for AMPs.*
4	Developing a Capital Investment and O&M spending portfolio optimization decision support strategy and process	Developing a framework that leverages analytics to prioritize investments against corporate values or performance objectives such that cost efficiencies can be achieved. This will include the development of a documented process, as well as documenting tool requirements that will perform the analytical tasks (to be built in-house or outsourced) and is expected to be developed over a 5 month period. AEY Execution Requirements Timetable: 5 months Level of Effort: High Cost: Low Capital: Possible if housed in a software
5	Asset Management System Documentation for Maintenance Practices	Introducing a documented maintenance manual that details the specific tasks, activities and frequencies associated with maintenance applied to each asset class within AEY's system. This manual will allow for these activities to be performed consistently, while also providing training for new employees. AEY Execution Requirements Timetable: 4 months Level of Effort: Low Cost: Medium Capital: Possible if housed in a software
6	Enterprise Asset Information Strategy	Introducing a centralized data model and data structure that associates specific data inputs to individual processes within the AM practice and establishing an implementation roadmap that prioritizes the most critical data to be centralized first. The data model and structure can

		then be leveraged to support specific business processes, frameworks (e.g. AHI) and enterprise systems, including GIS, EDMS, GIS and ERP systems. AEY Execution Requirements Timetable: 4 months Level of Effort: High Cost: Medium Capital: Possible if paired with a software implementation
7	Enhancing the collection, storage, maintenance, accuracy, completeness, and use of data	Introducing initiatives to collect asset registry and age data for assets from the field that have not been captured via the as-built procedures, to enhance overall data quality. This is expected to take 5 months for the introduction; however, the enhancement of data is an ongoing effort to meet changing needs. AEY Execution Requirements Timetable: 5 months Level of Effort: High Cost: Medium Capital: Possible if utilizing a software
8	Clarifying the approach to Critical Spares management	AEY should consider fully implementing the critical spares procedure as established by ATCO, to manage the risks within their system. This will also include a review and assessment of existing asset criticality plans and scenarios as well as asset-level contingency plans. Following implementation, AEY should monitor this procedure and be prepared to introduce enhancements to account for localized challenges that may be faced. AEY Execution Requirements Timetable: 3 months Level of Effort: High Cost: Medium Capital: Unlikely
9	AEY Organizational Strategy	AEY should consider developing a localized five-year business plan that aligns with its organizational objectives while establishing AEY-specific pillars, objectives and initiatives that are "right-sized" to the organization and service area within asset management. This will include the development of an optimized organizational structure to support the AM function, a resourcing plan that describes the volume of resources and associated costs, as well as performance measures to manage the effectiveness of the overall strategy. This is expected to take 6 months. AEY Execution Requirements Timetable: 6 months Level of Effort: Medium Cost: Low Capital: Unlikely

Table 4-3: AM Practice Priorities 2 and 3

Priority 2 & 3		
ID	Project/Recommendation	Description

1	Centralizing Decision-Making Data	Information used to support investments remains distributed and disconnected and must be manually collected and consolidated to support a given investment. It is recommended that AEY establish a formal system of record to support the central storage of all data, thereby creating a "single source of truth" that can be leveraged for all decision-making. Depending on the outcomes of the investigation, this system-of-record may take the form of GIS, ERP, CMMS or advanced analytics accelerator (i.e. ENGIN, Alteryx, PowerBI, etc.). This is expected to take 6 months. Benefit: Creating a single source of truth ensures that all data used to support a given capital or O&M investment or used to support regulatory reporting procedures are consistent and in alignment. A single source for data collection also introduces significant cost efficiencies within the organization, as data no longer needs to be manually consolidated from multiple locations. <u>AEY Execution Requirements</u> Timetable: 6 months Level of Effort: High Cost: High Capital: Possible if paired with a software implementation
2	Introducing Risk for Decision-Making	With age and condition-based analytics established (as per short-term recommendations), we would recommend as part of a long-term plan for AEY to consider risk-based analytics in their decision-making, to improve overall regulatory reporting and alignment with industry standards. Benefit: Leveraging risk to support capital and O&M decision-making not only strengthens the overall accuracy of the AM plans that are produced, but also brings AEY in closer alignment with industry standards, such as ISO 55000. A possible step for AEY for introducing risk into decision-making is driving failure probability curves. With age, condition and outage reporting data in place, there are opportunities for AEY to derive failure curves for their assets, accounting for the unique operating environment. These failure curves can be leveraged as part of a broader, risk-based AM planning approach. Benefit: Failure curves can be leveraged by AEY to predict what assets will fail, and to quantify the projected number of failures within a given year. These results can be leveraged to support enhanced regulatory reporting, and investment justification, and can be integrated into a risk-based AM planning framework. <u>AEY Execution Requirements</u> Timetable: 8 months Level of Effort: High Cost: High Capital: Possible if paired with a software implementation
3	Transitioning to Electronic Data Entry for Maintenance Records	With an AHI developed and a CMMS coming into place, it is recommended that AEY focus on the development of a new electronic

		maintenance data entry form, allowing in-field crews to enter specific details on assets as it relates to the AHI procedure. Benefit: Information recorded on paper must be re-entered electronically to sufficiently integrate this information into an AHI Framework. Recording inspection and testing results directly within an electronic platform will introduce significant cost efficiencies for AEY. <u>AEY Execution Requirements</u> Timetable: 7 months Level of Effort: Medium Cost: Medium Capital: Possible for software implementation
4	Enhancing overall IT/OT enablement with enhancements on the collection, storage, maintenance, accuracy, completeness, and use of data	In parallel with transitioning electronic data entry for maintenance records, AEY may want to consider transitioning all maintenance activities into a single CMMS platform. Benefit: CMMS allows for outputs from a given maintenance program to be easily stored, tracked, and integrated into analytical frameworks such as an AHI. CMMS also supports the prioritization and execution of maintenance activities. A CMMS implementation will result in improved cost efficiencies within the organization, as the maintenance program can be managed in a more automated manner. <u>AEY Execution Requirements</u> Timetable: 12 months Level of Effort: High Cost: High Capital: Possible for software implementation
5	Maintenance Optimization	With a CMMS in place, AEY will be able to better track the overall effectiveness of the program as it relates to the performance of the assets. It is recommended that AEY holistically assess and prioritize its maintenance activities based on cost, performance and risk. Through this assessment, lower-priority maintenance programs can be identified for modification should OPEX budget cuts need to be introduced. Benefit: Results from maintenance optimization can be leveraged to prioritize individual maintenance programs, such that the scope of maintenance may be expanded or contracted depending on the overall criticality of the program. <u>AEY Execution Requirements</u> Timetable: 5 months Level of Effort: Low Cost: Low Capital: Unlikely
6	Enhancing Asset Management System Documentation for Maintenance Practices	Application of standardized maintenance practices, including RCM or condition-based maintenance, will bring AEY in better alignment with industry practices, while also creating direct linkages between the maintenance actions and functional failures and failure modes that may emerge for each asset class.

		Benefit: Adopting maintenance standards allows AEY to better prioritize the maintenance activities, while optimizing maintenance tasks and frequencies, thereby reducing asset and system risks, and reducing overall operating costs. AEY Execution Requirements Timetable: 8 months Level of Effort: Low Cost: Medium Capital: Unlikely
7	Developing a Management of Change Process	The Management of Change (MOC) procedure and forms describe how changes will be reviewed and assessed for risk. The simplest, leanest, viable process and procedure to manage MOC are the desired goal. Currently, AEY has no MOC process. Benefit: Having accurate and up-to-date information on critical assets in-service will allow AEY to efficiently diagnose and correct issues on their system. Having outdated information or information managed by individual parties presents a risk for AEY's business in delivering safe and reliable energy to its customers. A MOC process would define the appropriate steps and individuals/teams accountable and responsible for communicating the relevant changes to the system. AEY Execution Requirements Timetable: 3 months Level of Effort: Low Cost: Low Capital: Unlikely
8	Performance Indicators for Data Management	It is recommended that AEY introduce key performance indicators (KPIs) for the continued management, validation and effectiveness of existing data being managed, along with new data being introduced into the system. Performance indicators will help link Data Management goals with organizational objectives, while also enhancing overall decision-making for the utility. Benefit: Having Data Management KPIs in place will allow AEY to holistically track data quality improvement efforts across the organization, while also identifying data quality efforts that should be reprioritized. AEY Execution Requirements Timetable: 4 months Level of Effort: Low Cost: Low Capital: Unlikely
9	Introducing a GIS to Manage Spatial Data	GIS systems are traditionally utilized not only to store asset registry/nameplate, age and spatial data but also to support connections to other processes, including maintenance (inspection data entry) and customer services (meter/transformer loading) processes. Benefit: The introduction of a GIS will establish a system of record for AEY that can be used to store pertinent decision-making data. While information from the existing CAD system, including asset registry and

		age data, can be migrated over, the GIS can also hold additional data relevant to AM decision-making, including connectivity and loading information. <u>AEY Execution Requirements</u> Timetable: 12 months Level of Effort: High Cost: High Capital: Likely
10	Documenting Finance and Corporate Reporting Procedures for Asset Management	There is currently no documentation that fully outlines the steps involved in variance reporting, regulatory reporting, and capital planning procedures. As part of a broader long-term roadmap, AEY should consider developing formalized procedures, that show the handoffs between AEY and ATCO. These documents will also support the training for new employees exposed to these processes. Benefit: Establishing formalized procedures will ensure that Finance and Corporate Reporting practices are executed consistently, while also providing training resources for new employees. <u>AEY Execution Requirements</u> Timetable: 6 months Level of Effort: Low Cost: Low Capital: Unlikely
11	Development of AEY Measures for Finance Performance	ATCO's Finance and Corporate Reporting group currently manages the KPIs associated with AEY's operation, including Asset Capitalization, Retirement and WIP. AEY may want to consider establishing its own localized KPIs to better align its AM and organizational objectives with those of the parent ATCO organization. Benefit: Establishing a series of localized KPIs that align with the KPIs of the parent ATCO organization will allow AEY's AM and organizational objectives to be more closely linked and aligned with those of ATCO. <u>AEY Execution Requirements</u> Timetable: 6 months Level of Effort: Low Cost: Low Capital: Unlikely
12	Developing a Formalized Enterprise Risk Management Program	There is a need for AEY to introduce a program to start managing broader enterprise risks, above and beyond their asset base. Benefit: An ERM program will allow AEY to better align their asset management and operational objectives with their organizational objectives such that critical risks can be managed across the organization. ERM also helps foster and build a risk management culture across the organization, such that risk-based elements can be better understood and more easily integrated across AEY's existing AM processes. <u>AEY Execution Requirements</u> Timetable: 6 months Level of Effort: Medium

		Cost: Medium Capital: Unlikely
13	Enhancing the Asset Risk Management process	Many functions within AEY's ERM practice are managed through the parent ATCO organization. While this may introduce cost efficiencies and savings within the organization, it may also result in the introduction and application of processes that are not "right-sized" for the organization. AEY should consider shifting certain ERM functions locally, in instances where the existing ATCO process is incompatible with the local operation. This includes the IT and training and development functions. Benefit: While leveraging pre-existing processes as defined by ATCO may introduce up-front savings, incompatible processes and functions can result in higher cost impacts over time. Leveraging "right-sized" processes such as a streamlined approach for identifying and analyzing risks will lead to reduced cost impacts over time. <u>AEY Execution Requirements</u> Timetable: 8 months Level of Effort: Medium Cost: Low Capital: Unlikely

As the AM roadmap is implemented, AEY's efforts will need to solidify any operational or behavioural changes required to affect this asset management transformation. Some key tasks that will prove valuable for this scope of work include:

- Development and presentation of the asset management plan to all internal stakeholders (workshop settings tailored to each stakeholder group to ensure a proper knowledge base on which to operate).
- Collaboration in building the revised AM System (group sessions to transfer "ownership" of the implementation plan to each respective internal stakeholder group).
- Determining the existence of any skills and competencies gaps across asset strategy, investment and program planning, asset information and enabling technology, investment and program delivery, performance management, and resource and contract strategy (define gaps to fill to implement and ensure sustainment of the AM Implementation Plan) effectively/efficiently.
- Creating momentum for change (driving immediate improvement to create an initial groundswell of support).
- Proactively addressing known objections to and/or challenges inherent in taking on this initiative (workshop settings tailored to each internal stakeholder group to address the naysayers).
- Addressing the behavioural aspects of the transformation (facilitated workshops with each internal stakeholder group and individual discussions as required throughout the process to initiate more rapid and achieve sustainable change)
    - Achieving and sustaining organizational alignment (clear linkage between organizational priorities and what people are working on, prioritization of measurable objectives, clear understanding of the issues and how everyone's efforts affect them, and accountability are both owned and required).
    - Workflow communication or coordination of action (clear and concise communication, seeking agreement through active listening and asking probing questions,

understanding/differentiating between a request or statement of belief, willingness to confront directly/no hidden agendas, and establishing clear expectations)

- Organizational readiness for change (Addressing 7 domains that affect an organization's readiness for change (i.e., Group Optimism, Trust and Involvement, Integrity and Respect, Clarity of Direction, Performance Accountability, Market-Drive Focus, and Learning Orientation)

- Training and continuing education to keep the topic front of mind and revisit/reemphasize key AM concepts, processes, and practices. This can be reinforced through an established process for continuous improvement so that AEY is sustainable on its own post-implementation.

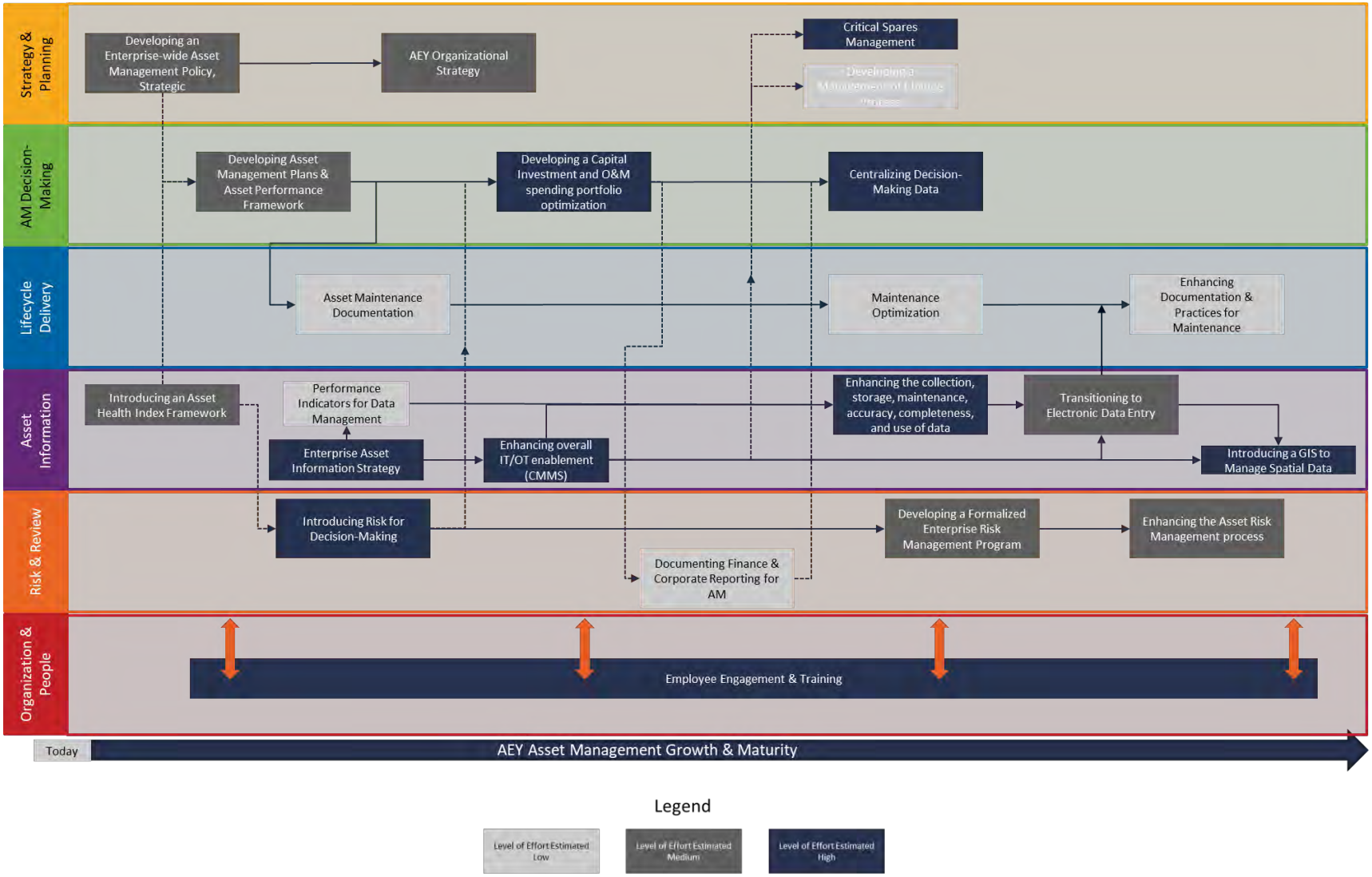


Figure 4-2: Suggested order of operations

5 Appendix A – Asset Management Initiative Project Descriptions

AEY-01

AEY-01: Implementing an Asset Health Index framework for distribution and generation assets to **support the effort of improving AEY's asset lifecycle** decisions and data management

This initiative focuses on implementing an Asset Health Index (AHI) framework to develop asset analytics within AEY and integrating asset inspection and testing results to support capital investment plans. Leveraging AHI results eliminates the need to manually analyze and interpret raw testing results, thereby introducing cost efficiencies and reducing the reliance on subjective judgements. Age-based analytics also allows AEY to identify system-wide backlogs, thereby justifying the overall need to invest in the system. AHI also represents a strong integration point between OPEX and CAPEX-related processes. Finally, AHI represents a foundational input into the broader development of a risk-based asset management framework, where AHI results can be leveraged in conjunction with asset criticality results to derive a risk matrix.

Executive Sponsor	John Williams	**Key Stakeholders**	Engineering, Operations, Planning, Maintenance
Initiative Owner	Kyle Rolling		

Priority	High	Medium	Low

Implementation Cost (,000s)	Low	High
	$45	$150

Initiative Dependencies

None

ATCO Electric Yukon Asset Management Principles Alignment

- Maximize the life cycle value of the physical assets to ensure cash flows are optimized and predictable over the life of the assets.
- Actively manage all inherent risks and opportunities related to safety, environment, financial and equipment performance.
- Optimize investment in maintenance and management of operations to achieve performance, consistent with maximizing the life cycle of the assets.
- Practice effective cost control by managing the physical assets and supporting systems.

Current State (Issues/Problems/Concerns)

The following statements describe the current state for asset management governance in AEY:

Asset Health Index Procedure

- No clear process exists to integrate and utilize maintenance data per asset unit and determine the overall health of the asset.
- No centralized data repository to manage all assets and their nameplate and condition data to support additional analytics and sensitivity analysis.
- AEY does leverage technical reports in addition to their subject-matter expertise to identify and prioritize capital investments, they have yet to apply individual asset analytics that would allow for system-wide planning needs to be identified in a consistent manner.
- Not enough people have access/accountability to improve all the asset planning information and decision-making.

Asset Health Index Framework & Analytics

- Dependent on tribal knowledge of the assets and systems to inform the annual investment plans.
- AEY leverages raw asset testing results to support the identification and prioritization of assets within distribution projects. However, additional time and effort are spent to analyze and interpret the raw testing results.
- No centralized data repository to manage all assets and their nameplate and condition data to support additional analytics and sensitivity analysis.
- Absence of supporting analytics and integration of plans with other inter-related teams or groups of assets which can present loss of efficiency.
- Do not produce insight on asset and system health to justify replacement increases which in turn are rate increases for rate payers.
- Not enough people have accountability or capacity to integrate various elements of an asset's lifecycle into a single source to be efficiently managed.

Future State (Desired Specific/Measurable Outcomes)

Desired Outcomes	Success Measures (KPIs)
Needs and accountability understood	Implemented procedure with roles and accountability defined
Established asset health criteria for major asset classes	Developed and utilized an asset health index framework aligned to industry practice
Assessment of data gaps for the framework	Key assessment criteria (baseline) for current data quality and gaps
Improved data completeness	Defined KPIs for measured improvement against baseline established above.

Investigation and Solution Planning Tasks (Key Activities)

1. Meet with Sponsor, Initiative Owner, and Stakeholders to discuss the scope boundaries.

2. Identification of key stakeholders and staff that will be responsible for utilizing and maintaining the AHI procedure and framework.
3. Draft the AHI procedure outline complimenting AEY's existing procedures for capital and maintenance planning.
4. Identify industry implemented AHI frameworks for major asset classes.
5. Assess where the necessary data resides and its current state (quality, completeness).
6. Tailor AHI framework to available information present at AEY.
7. Deliver workshops to capture and assess historically collected condition data for each asset unit and document any assumptions incorporated. Deliver workshops to refine the AHI and train users in roles and responsibilities.
8. Document related data gaps, requirements, and quality for completing the AHI assessment.
9. Establish team to monitor data quality and drive improvement.
10. Develop improvement plan with recommendations on any technology/analytics related enhancements.

AEY-02

AEY-02: Develop asset management governance to **support the effort of improving AEY's asset** management decisions

This initiative focuses on expanding AEY's Asset Management Vision and developing an Enterprise-wide Asset Management Policy, Strategic Asset Management Plan and developing specific Asset Management Plans for Major Asset Classes. Formal documentation ensures that the AM practice is applied consistently, and new employees can easily learn about the underlying procedures & methodologies. The AM Policy allows AEY to align their AM objectives with organizational objectives. Furthermore, documentation can introduce efficiencies with GRA audits or justifications for investment projects.

Executive Sponsor	John Williams	**Key Stakeholders**	Engineering, Operations, Planning, Maintenance
Initiative Owner	Kyle Rolling		

Priority	High	Medium	Low

Implementation Cost (,000s)	Low	High
	$20	$75

Initiative Dependencies

None

ATCO Electric Yukon Asset Management Principles Alignment

- Optimize investment in maintenance and management of operations to achieve performance, consistent with maximizing the life cycle of the assets.

- Practice effective cost control by managing the physical assets and supporting systems.
- Maintain, review and continuously improve the Asset Management System to align with ATCO, regulatory compliance, ISO 5500x and other industry-recognized standards for Asset Management.

Current State (Issues/Problems/Concerns)

The following statements describe the current state for asset management governance in AEY:

Asset Management Governance (Policy & Strategy)

- No clear alignment or connection between AEY's asset management approach to parent ATCO's asset management vision.
- AEY's strategy asset planning process is not formally documented, along with AM objectives, capital and maintenance strategies, and investment approaches for individual asset classes.
- Not enough people have access/accountability to improve all the asset planning information and decision-making.

Asset Management Plans

- The level of documentation for asset planning could be improved and standardized.
- Lack of supporting analytics and integration of plans with other inter-related teams or groups of assets which can present loss of efficiency.
- Not enough people have accountability or capacity to integrate various elements of an asset's lifecycle into a single source to be efficiently managed.

Future State (Desired Specific/Measurable Outcomes)

Desired Outcomes	Success Measures (KPIs)
Needs and accountability understood	Information mapped to asset lifecycle funding decisions.
Defined AM objectives	Defined KPIs for measuring progress against objectives.
Agreed to approach for assessing assets	Completed strategy and roadmap.
Improved asset lifecycle management	Defined KPIs for measured improvement against baseline established.

Investigation and Solution Planning Tasks (Key Activities)

1. Meet with Sponsor, Initiative Owner, and Stakeholders to discuss the scope boundaries.
2. Identification of key stakeholders and staff that will be responsible for maintaining and applying the AM Policy, SAMP, and AM Plans.
3. Draft the template outlines for each document following the requirements of industry practice.
4. Assess where the necessary data resides and its current state (quality, completeness)
5. Deliver workshops to develop and document key strategic criteria aligned to the corporate vision. Deliver workshops to refine the asset management principles and objectives with the vision.

6. Document core decision making functions and related data requirements.
7. Draft the necessary documents in consideration of the project boundaries, outcomes, and data availability.
8. Develop improvement plan for the governance files with recommendations on any technology/analytics related enhancements.
9. Establish team to monitor and drive improvement.
10. Executive team buy-in, sponsorship and championing the governance documents throughout AEY.

6 Appendix B – Asset Management Governance Guidelines

6.1 Asset Management Policy Guidelines

An Asset Management Policy should be created that will meet the requirements of ISO 55001. The policy must include at minimum the following sections:

- Intent – An outline of senior management's commitment, intention, and expectations related to asset management.
- Scope – A summary of all services and assets covered in the policy. This will include both existing assets and mechanisms for deciding what new future assets will be included. References to any related policies or procedures will also be listed in this section.
- Principles – Statements of the asset management principles that all asset management decisions will be compared against. This should include commitments to satisfying any legal, regulatory, or third-party requirements. These principles should align with AEY's Asset Management Objectives.
- Responsibilities – This section will outline the parties responsible for all aspects of the policy and system. This includes approvals, allocation of resources, implementation, and other high-level actions involved in administering the AM system.
- Continual Improvement – This section will outline the commitment of the organization to continual improvement of the AM system and how it intends to accomplish that. It will also outline the documentation requirements of the policy and the frequency to which it needs to be reviewed.

6.2 Strategic Asset Management Plan Guidelines

The Strategic Asset Management Plan (SAMP) should be developed in accordance with requirements of ISO 55001. It must include the following items:

- Scope - Outline the assets that are subject to the asset management system. This can include tables, maps, diagrams, etc.
- Related Corporate Documents - List any relevant corporate strategic documents and how they relate to the SAMP.
- Asset Management System - A flow chart and description of the organization's Asset Management system. Also, include the organizational charts that authorize and define the Asset Management system. Reference the location and title of any documents used within the system (Asset Management Policy, Asset Management Plans, etc.).
- Organizational Context - Provide a brief description of the internal and external issues that could affect the organization's Asset Management system.
- Organizational Opportunities and Challenges - Outline the opportunities and challenges related to the asset management plan. Outline the strategies and actions that can be taken to either mitigate or eliminate the challenges and obtain the highest benefit from the potential opportunities.
- Needs and Expectations of Stakeholders - List all the internal and external stakeholders in the Asset Management system. Include the communication and any Level of Service ("LOS") guarantees or targets that those stakeholders expect to be met.

- People, Skills, and Competencies - Establish the roles and responsibilities of those involved in the Asset Management system. This should also include the competencies and skills required to fulfill those roles and responsibilities.
- Asset Management Objectives - Outline the Asset Management system objectives and how they align with AEY's Asset Management Objectives.
- Asset Management Plans – Provide an outline for creating Asset Management Plans ("AMP"). This should include the required contents of the AMP, who is responsible for developing the plans, and how the AMP relates to the Asset Management Objectives.
- Continual Improvement and Monitoring - Establish Key Performance Indicators ("KPIs") for monitoring the effectiveness of the Asset Management system. These KPIs should follow the SMART format as Specific, Measurable, Attainable, Relevant, and Time-Based. Outline how the organization will use these KPIs to continuously improve the Asset Management system to ensure the Asset Management Objectives and AEY's Organizational Objectives are being met.

6.3 Asset Management Plan Guidelines

An Asset Management Plan (AMP) should be developed for each of the asset subclasses that are deemed to need one. The plans should meet the requirements for ISO 55001. They will outline the actions required to ensure the asset is performing to specific LOS guarantees that are aligned with AEY's Asset Management Objectives. To accomplish this, the plan should include the following topics:

- Asset Information
  - Outline the basic attributes of the asset such as typical useful life, current value, asset history, etc.
  - Summarize the current state of the asset class inventory including count and condition.
  - Define the data available for the asset, data sources, and the confidence in that data.
  - List any interdependencies between the asset class and other asset classes such as parent-child relationships.
  - List any interdependencies between the AMP and scopes of work, guidelines, policies, or plans.
- Expectations
  - Outline the expectations the organization has of the asset as a LOS and how those relate to AEY's Asset Management Objectives.
  - Summarise the various stakeholders, along with their roles, responsibilities, and communication requirements involved in the lifecycle management of the asset.
  - Outline expected demands, life-limiting factors, and their respective forecasts.
- Management Strategies
  - Describe the lifecycle management strategies (procurement, installation, operation, maintenance, and retirement) and activities of the assets along with their decision criteria.
  - Specify the resources (financial, informational, labour, equipment, material, etc.) required to perform the activities involved in the lifecycle management activities.

  - Define the risks to LOS of the asset class based on the consequence, probability, and detectability of asset functional failure along with how to calculate those metrics.
- Improvement Plan
  - Define the review and improvement process for the plan itself
  - List the recommended initiatives to improve the overall management of the asset (e.g. model asset class in the asset inventory system; increase the scope, granularity, or frequency of data capture for the asset class)

ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

New Substations - Mayo Road and Whistle Bend

2023-2024 Business Case #25

Executive Summary

1. Continued load growth on the Alaska and Klondike Highway North, as well as rapid growth in the Whistle Bend community poses strain on the AEY system and its ability to provide safe and reliable power. The Whitehorse North 25 kV system does not have the capacity to provide needed contingency between the existing substations within the next six-years.

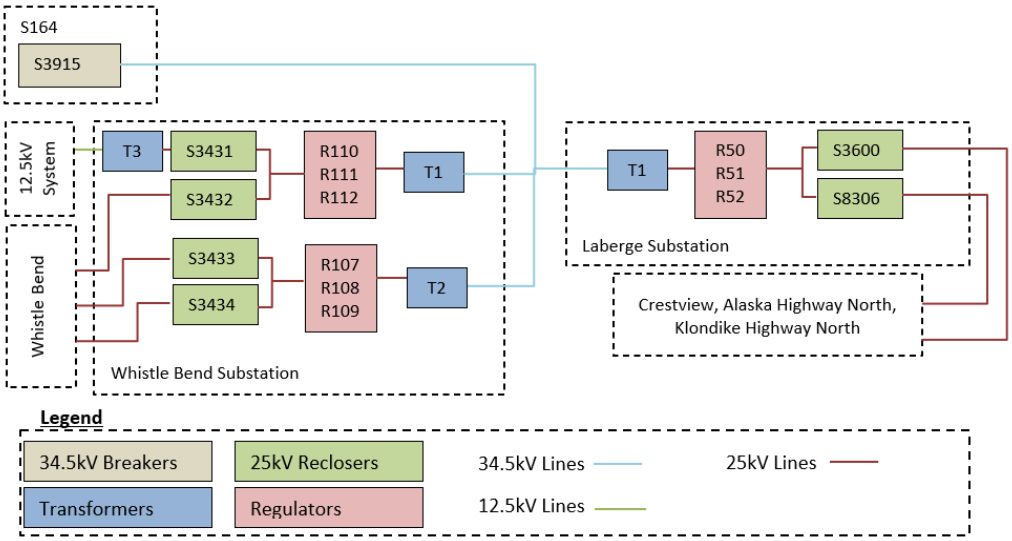
Background

2. Load growth continuously pushes a power system closer to its capacity limits. This leads to electrical equipment being operated past its capacity, which compromises the safety and reliability of the network.

System Configuration

3. 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.

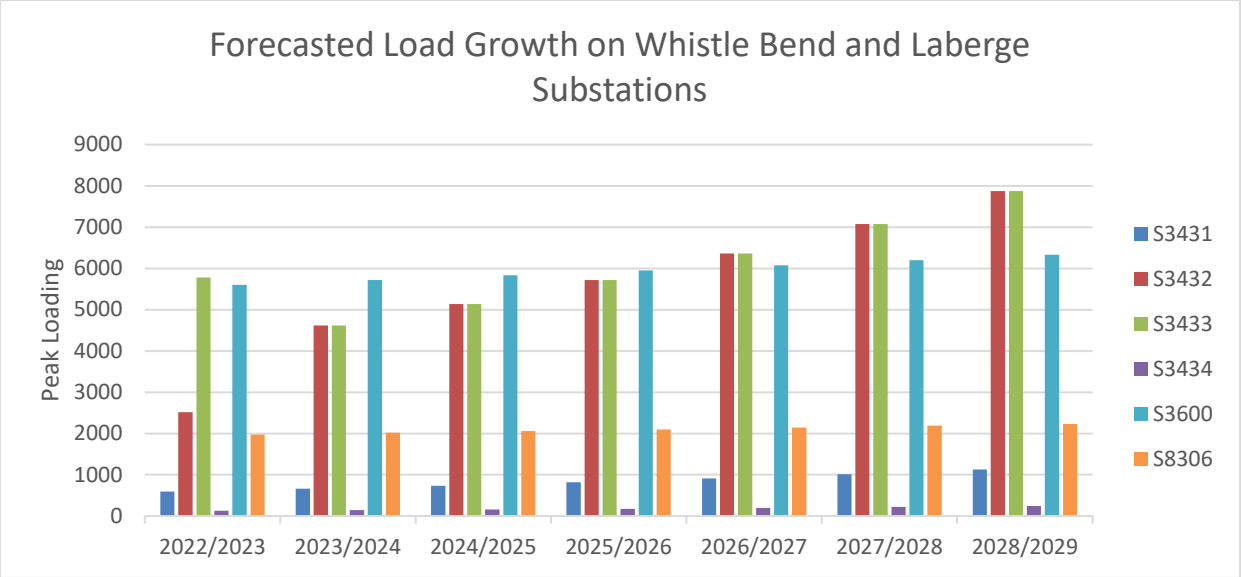
Figure 1: Whitehorse North 25 kV System During Normal Operation



Forecast Load Growth

4. Currently the Whistle Bend Subdivision is undergoing extensive construction and is expected to complete Stage 7 by the end of 2023. Using historical SCADA data from Whistle Bend Substation, year-over-year load increase was modeled at 11.26 percent. Historical Laberge Substation SCADA data proved a 2.06 percent year-over-year load increase along the North Alaska Highway, North Klondike Highway and Crestview.

Figure 2: Forecast Load Growth for Whistle Bend and Laberge Substations until the 2028/2029 Winter.



* 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.

Project Description

5. 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. This addition will increase overall capacity of the North 25 kV distribution system, providing greater contingency capabilities and increased voltage stability.

6. The project will consist of:

- Two New Substations;
    - 10 MVA substations taking over the Laberge feed to Alaska Highway North, Klondike Highway North and supplementing the existing Whistle Bend Substation.
- New System Configuration;
    - Added switching to accommodate the new substations and for contingency scenarios.
- Regulator Bank Salvage;
    - R113/R114/R115 regulator bank no longer needed on Klondike Highway North.

Project Schedule and Cost

Table 1: Project Schedule & Cost ($000)

	Cost	Target In-Service Date
Procure Mayo Road Substation Transformer	400	2022
Build and Commission Mayo Road Substation	2,554	2023
New System Configuration		
Salvage Mayo Road Regulator Bank		
Build and Commission Whistle Bend 2 Substation	2,781	2024
New System Configuration		

Business Drivers and Benefits

7. For the loss of any major equipment within the electrical distribution system, AEY requires that there be a plan in place on how to restore power to as many customers as quickly as possible. Ideally, this means the peak load of any piece of equipment can be transferred to an alternative feeder/breaker/source to re-energize the customers without the failed equipment.

8. For the North 25 kV System, the following cases are being considered as potential issues both presently and within the six-year planning window:

Table 2: North 25 kV System Contingency Analysis

Contingency Scenario	Description	Present Status (2023)	Future Status
1. Loss of 6L17	6L17 is the normal source of 34.5kV to both Whistle Bend and Laberge substations from S164. A loss of this line will require both distribution substations to be transferred to 6L16 (loading limit of 38MVA) and source from T1 at S170 (loading limit of 47MVA).	Overload – Current peak loading of 16.6MVA on North 25kV System. S170 and S150 do not have the capacity to receive this transfer.	Overload – Current peak loading of 16.6MVA on North 25kV System. S170 and S150 do not have the capacity to receive this transfer.
2. Loss of single 34.5/25kV transformer	Between Whistle Bend and Laberge Substations, there are 3 x 10MVA transformers for 34.5/25kV. Assuming adequate switching to distribute load among remaining 2 transformers, overall load cannot exceed 20MVA.	OK – Current peak loading of 16.6MVA.	Overload - Capacity reached in 2029. Expected peak loading of 25.7MVA on North 25kV System.
3. Loss of 34.5kV primary bus at Whistle Bend	The loss of the primary bus at Whistle Bend will prevent any 25kV sourcing from this substation. All load will have to be transferred to T1 at Laberge Substation (10MVA rating).	Overload – Currently at peak load, the North 25kV system requires more capacity than T1 at Laberge can supply.	
4. Loss of 25kV breaker at Whistle Bend	The loss of a single 25kV breaker at Whistle Bend or Laberge would require all load to be transferred to the remaining breakers on the North 25kV system.	Ok	Ok

Evaluation of Viable Alternatives

OPTION 1: New 25 kV Substation & System Reconfiguration

9. Building a new substation for the 25 kV North System would directly resolve Contingency Scenarios 2 and 3, by providing additional reserve capacity to assist with system reconfiguration during outages. In 2029, the total peak loading on S164 is estimated to be 25.7 MVA. In Contingency Scenario 3, the only remaining transformer is T1 at Laberge, with a rating of 10 MVA. This results in 15.7 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 15.7 MVA without overloading any equipment.

Alternative 1: Whistle Bend Substation 2 (WB2)

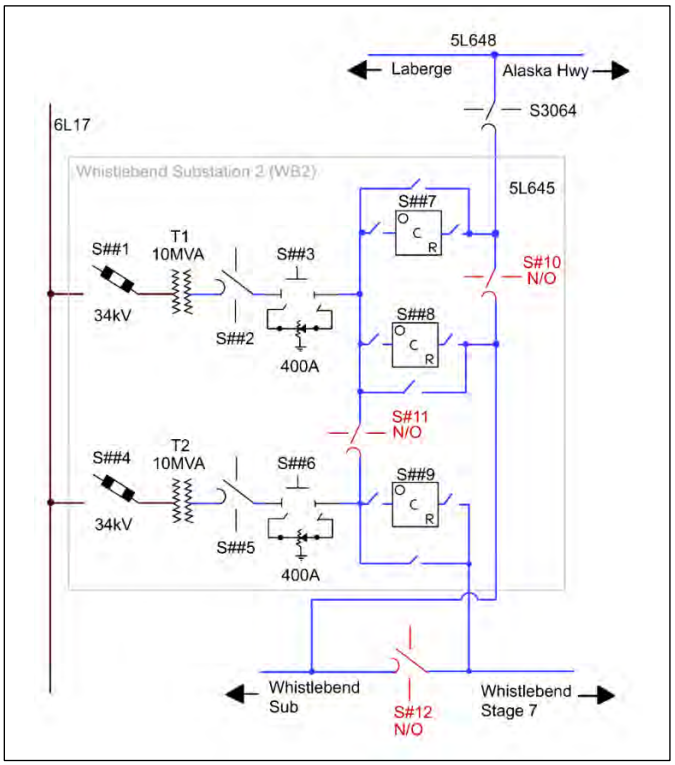
Overview

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

Equipment/Apparatus Requirements

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

Figure 3: Whistle Bend Substation 2 (WB2)



Additional System Improvement Requirements

11. In order to connect Whistle Bend 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 3);
- A recloser connecting WB2 Feeder 2 to Whistle Bend Stage 7 (labelled as "S##9" in Figure 3); and
- A recloser connecting WB2 Feeder 3 to serve as hot spare for Whistle Bend Substation (labelled as "S##8" in Figure 3).

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

Contingency Operation

13. The proposed Whistle Bend Substation 2 fully addresses the future loading requirements for both of the contingency scenarios identified. In Contingency scenario 2 (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.

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

System Voltage Improvement

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

Alternative 2: Laberge Upgrade & Takhini Hot Springs Road Substation (TK1)

Overview

16. This solution involves a two-part approach to meeting the desired system capabilities: upgrading Laberge Substation and constructing a new 10 MVA substation near the intersection of Takhini Hot Springs Road and Klondike Highway North. The new substation will service all of the 25 kV System on Alaska Highway and Klondike Highway north of Whitehorse. This area was previously serviced by Laberge Substation and will offload approximately 6 MW 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 10 MVA.

Equipment/Apparatus Requirements

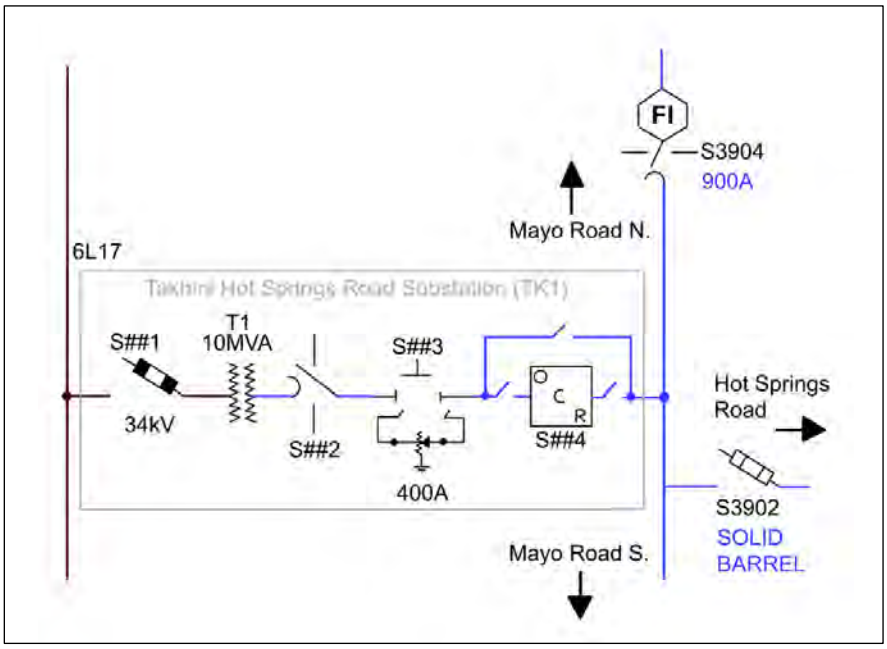
For TK1:

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

For Laberge:

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

Figure 4: Takhini Hot Springs Road Substation (TK1)



Additional System Improvement Requirements

- A recloser connecting TK1 to the 5L648 along Klondike Highway North (labelled as "S##4" in Figure 4.).
- 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 Whistle Bend, while isolating the highways that will be supplied by TK1.

Contingency Operation

17. 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 future. During Contingency Scenario 2 (loss of 34.5/25 kV transformer at Laberge), the regular load serviced by Laberge would be transferred to Whistle Bend Substation via recloser S3434. One possible switching operation to achieve this would be to isolate Laberge T1 and then back-feed Laberge substation from Whistle Bend's S3434 and feed through S3600 and continue to supply the Crestview area through S8306.

18. In the event of Contingency 3 (loss of primary bus at Whistle Bend), the reverse of the Contingency 2 restoration will occur. Laberge will source the power for Whistle Bend

subdivision and feed through S3600 and feed into Whistle Bend 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 Whistle Bend, close-in N/O S3434 to connect all 4 reclosers at Whistle Bend, close-in stage-7 tie-in, close-in S3064 to tie 5L645 and 5L648 together, and close-in recloser S3600 at Laberge.

System Voltage Improvement

19. Overall, the North 25 kV system would experience a 9.35 percent voltage improvement across the three 34.5/25 kV substations if compared against how the current system configuration would perform with future peak loading. EOL customers are expected to have a 1.9 percent voltage improvement as well.

Alternative 3: Whistle Bend Substation 2 (WB2) & Takhini Hot Springs Road Substation (TK1)

Overview

20. Similar to Alternative 2, this alternative takes a 2-part approach to meet the desired system capabilities; however, this option involves the construction of two (2) new substations: Takhini Hot Springs Road Substation (TK1) and Whistle Bend Substation 2 (WB2). Identical to Alternative 2, TK1 would be a 10 MVA 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 25 kV system, therefore offloading approximately 6 MW from Laberge Substation. If selected, this option would involve the construction of WB2 with only a single 10 MVA transformer and would be located near Stage 7 of the Whistle Bend Subdivision (same location as WB2 in Alternative 1). This substation would service Stages 4-7 of the Whistle Bend 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.

Equipment/Apparatus Requirements

For TK1:

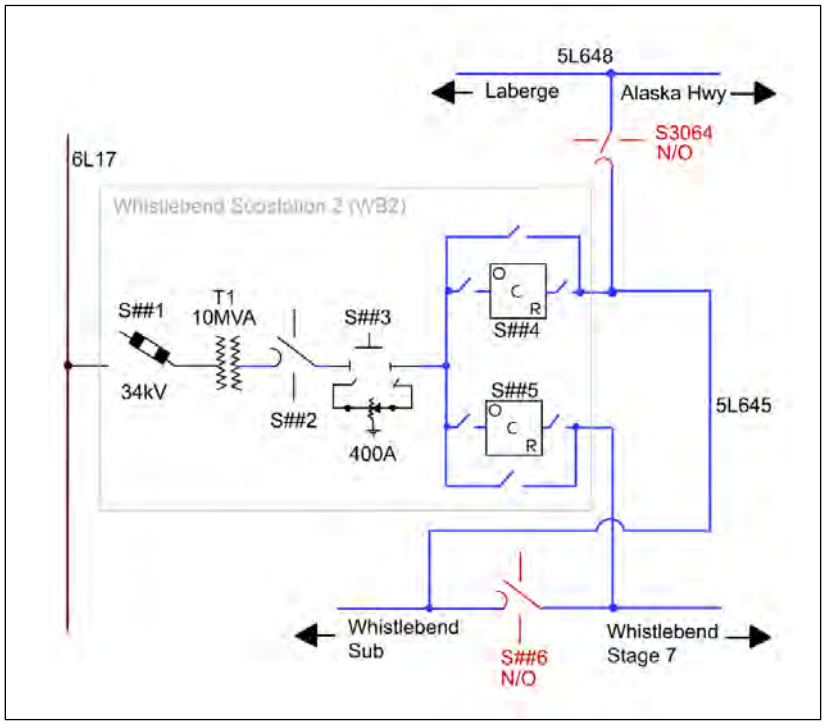
- 1 x 10 MVA 34.5/25 kV Transformer;

- 3 x 400 A 25 kV Regulators; and
- 1 x 630 A 25 kV Reclosers.

For WB2:

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

Figure 5: Whistle Bend Substation 2 – 10 MVA Option (WB2)



Additional System Improvement Requirements

21. This proposal includes the addition of two (2) new substation; 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 4.).
- Inline N/O switch on 5L645 just north of the junction with 5L648. This will keep the hot-spare tie-in between Laberge and Whistle Bend, while isolating the highways that will be supplied by TK1.
- A recloser connecting WB2 to 5L648 (labelled as "S##4" in Figure 5.).

- A recloser connecting WB2 to Whistle Bend Stage 7 (labelled as "S##5" in Figure 5).

22. A comprehensive set of the switching devices required at WB2 is displayed in Figure 5.

Contingency Operation

23. The proposed combination of constructing a Takhini Hot Springs Road Substation and a new Whistle Bend Substation 2 would fully meet the system requirements for future. In Contingency Scenario 2 (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.

24. If the system was in Contingency Scenario 3, all of the typical Whistle Bend 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 Whistle Bend Substation through S3434, while WB2 would continue to feed into stage 7 and could take on more of the Whistle Bend load by moving the open point further downstream.

System Voltage Improvement

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

OPTION 2: Status Quo

26. Without making any changes to the North 25 kV system and with load growth continuing at the expected rates, equipment will be overloaded in the near future. 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 8 hours before the loading must drop below 0.90 p.u.

27. Utilizing these seasonal equipment ratings, the North 25 kV System will be able to handle Contingency Scenario 1 up until 2027. In 2027, the peak loading on the North 25 kV System is anticipated to be ~23.8 MVA. This load cannot be carried by two operational transformers.

28. 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.

29. Option 2 covers Contingency Scenario 2 up until 2027 and does not cover Contingency Scenario 3.

30. To facilitate a comparison of the three 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 25 kV system are eliminatory elements on the decision matrix. Therefore, if any solution does not fully address each of these criteria, the solution would be removed from consideration. 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 Tables 6 and 7.

Table 6: Decision Matrix

				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	**10**	3	**15**
Totals:				75		68		79	

Table 7: Legend for 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)

Recommendation

31. Each proposed alternative was individually evaluated against equipment loading limits, system voltage requirements, and restoration-switching guidelines. Additionally, among all the proposed alternatives, a comparative cost analysis was performed based on previously completed substation projects and the main expected costs for each design. After calculating the decision matrix, it was determined that Alternative 3 is the recommended solution to meet the North 25 kV system requirements. Alternative 3 will include the construction of a new 10 MVA substation on the north-west side of Whistle

Bend Subdivision, as well as the construction of a new 10 MVA substation near the junction of Takhini Hot Springs Road and Klondike Highway North. This alternative will meet all the key requirements and will well-position the North 25 kV for future expansions beyond the six-year planning window.

ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Annual Right-of-Way (ROW) Widening

2023-2024 Business Case #26

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 annual right of way widening 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 trees outside the existing right of way.

Background

3. In 2023 and 2024, capital brushing work will be required on various areas of the power system.

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 an ongoing 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 & Cost

2023 - $520,000.
2024 - $528,000.

Business Drivers and Benefits

7. 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 standard and extent sufficient to maintain safe operations.

Evaluation of Viable Alternatives

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

Recommendation

9. Continue with the ongoing five-year capital brushing plan.

ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Fleet Replacement 2023

2023-2024 Business Case #27

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. 2023 fleet replacement has identified three service vehicles (over $100,000) that meet the threshold for replacement. Two vehicles are also required to be purchased as fleet additions:

- Addition YT161 was purchased for use by a new mechanic position.
- Addition YT162 was purchased for use by a new Power System Electrician.

Project Description

3. Procurement of these five vehicles through ATCO Fleet and third party vendors.

Project Schedule and Cost

Table 1: Fleet Replaced

Unit	Description	Year Purchased	Kilometers
YT116	LD Service Body	2013	245,537
YT117	LD Service Body	2013	237,000
YT099	LD Service Body	2010	248,748

Table 2: Purchased Fleet 2023

Unit	Description	Year Purchased	Purchase Cost ($)
YT160 (Replaces YT116)	LD Service Body	2023	110,000
YT161 (Fleet Add)	Technologist Truck	2023	160,000
YT162 (Fleet Add)	Generation Truck	2023	160,000
YT163 (Replaces YT117)	LD Service Body	2023	110,000
YT164 (Replaces YT099)	LD Service Body	2023	110,000
Units under $100,000	Various[1]	2023	47,000
Total			**697,000**

[1] Category includes items such as trailers, snowmobiles, and all-terrain vehicles. These units are evaluated for replacement using the lifecycle criteria evaluation after seven-years of service or 200,000 km.

Business Drivers and Benefits

4. The typical lifecycle of an AEY fleet vehicle is evaluated after seven-years of service or 200,000 km. All the vehicles in the above table exceeded this criterion and required replacement, aside from the two additions. Replacement of these vehicles improves reliability and reduces maintenance costs. Traveling is regularly required to Service Points throughout the Yukon, and with this comes the need for a vehicle that is capable of driving in all weather conditions. Additionally, these positions support the on-call roster and are expected to be available at all times when assigned on-call duties.

5. The fleet additions (YT161 and YT162) are to address the addition of two new FTE positions requiring work vehicles.

Evaluation of Viable Alternatives

Alternative 1

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

Alternative 2

7. Renting or leasing the equipment to support these permanent positions, this is subject to equipment availability.

Recommendation

8. Replacement of and addition to fleet with new vehicles as proposed above.

ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Fleet Replacement 2024

2023-2024 Business Case #28

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. 2024 fleet replacement has identified four (4) service vehicles (over $100,000) that meet the threshold for replacement. A material handler exceeded its threshold for operating hours.

All vehicles are projected to meet or exceed the business driver for replacement in 2024.

Project Description

3. Procurement of these five vehicles through ATCO Fleet and third party vendors.

Project Schedule and Cost

Table 1: Fleet Replaced

Unit	Description	Year Purchased	Kilometers
YT109	MD Ram 3500 Flat	2012	206620
YT125	Teletruck Forklift	2014	1838 hrs
YT129	MD Ram 3500 Flat	2014	114800
YT133	MD Ram 2500 SB	2015	145687
YT135	MD ram 2500 Flat	2015	174972

Table 2: Purchased Fleet 2024

Unit	Description	Year Purchased	Purchase Cost
YT165 (Replaces YT109)	LD 3500 Flat Deck	2024	110,000
YT166 (Replaces YT129)	LD Service Body	2024	110,000
YT167 (Replaces YT133)	LD Service Body	2024	110,000
YT168 (Replace YT135)	LD Service Body	2024	110,000
YT170 (Replaces YT125)	HD ForkLift MH	2024	150,000
Units under $100,000	Various[1]	2024	176,000
Total			**766,000**

[1] Category includes items such as trailers, snowmobiles, and all-terrain vehicles. These units are evaluated for replacement using the lifecycle criteria evaluation after seven-years of service or 200,000 km.

Business Drivers and Benefits

4. The typical lifecycle of an AEY fleet vehicle is evaluated after seven-years of service or 200,000 km. All the vehicles in the above table exceeded this criterion and required replacement, aside from the material handler that exceeded its operating hours. Replacement of these vehicles improves reliability and reduces maintenance costs.

Evaluation of Viable Alternatives

Alternative 1

5. Extending the life cycle period for fleet vehicles is considered; however, this option leads to a reduction in reliability and an increase in maintenance costs. Additionally, as the power system evolves, larger materials in excess of 10,000 lbs are required to be handled more frequently. This requires replacements to meet the new needs of the material handling.

Alternative 2

6. 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.

Alternative 3

7. Contracting out cranes or material handling, which is subject to availability and the need for a 24hrs on-call rate.

Recommendation

8. Replacement of fleet with new vehicles as proposed above.

ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Old Crow Voltage Improvement

2023-2024 Business Case #29

Executive Summary

1. The voltages at the end of line in Old Crow are currently below the 0.95 p.u. operating standard, and new loads are planned in the community that will pull the voltage even lower. This is an ongoing problem in the community that has been mitigated but not solved by upgrades in the past.

Background

2. 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

3. Further investigation revealed that this is an ongoing problem in the community that has been mitigated but not solved by upgrades in the past. Old Crow continues to see load growth year over year. The existing infrastructure is becoming undersized and ill-equipped to provide electricity to customers within AEY standards. The main factor behind this Business Case is ensuring services receive voltages that are above AEY's minimum distribution voltage of 0.95 p.u. and the two main factors that affect voltage performance are: the distance from voltage source to customer and the size of wire between those two points. Through the options of rephasing to redistribute load, adding regulators and increasing wire sizes (reconductoring), a final recommended solution containing all three of those options was reached.

Project Description

4. This project includes reconductoring of two main feeders in Old Crow: 3L406 and 3L405. Existing conductor sizes on 3L406 range from #4 ACSR to #6 ACSR and will be reconductored between the Old Crow diesel plant and recloser S3788 with 1/0 ACSR. The 3L405 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 reconductored 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 downstream of the Old Crow PV Site at Location 3 as seen in Alternative 1.

Project Schedule and Cost

Table 1: 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

5. 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

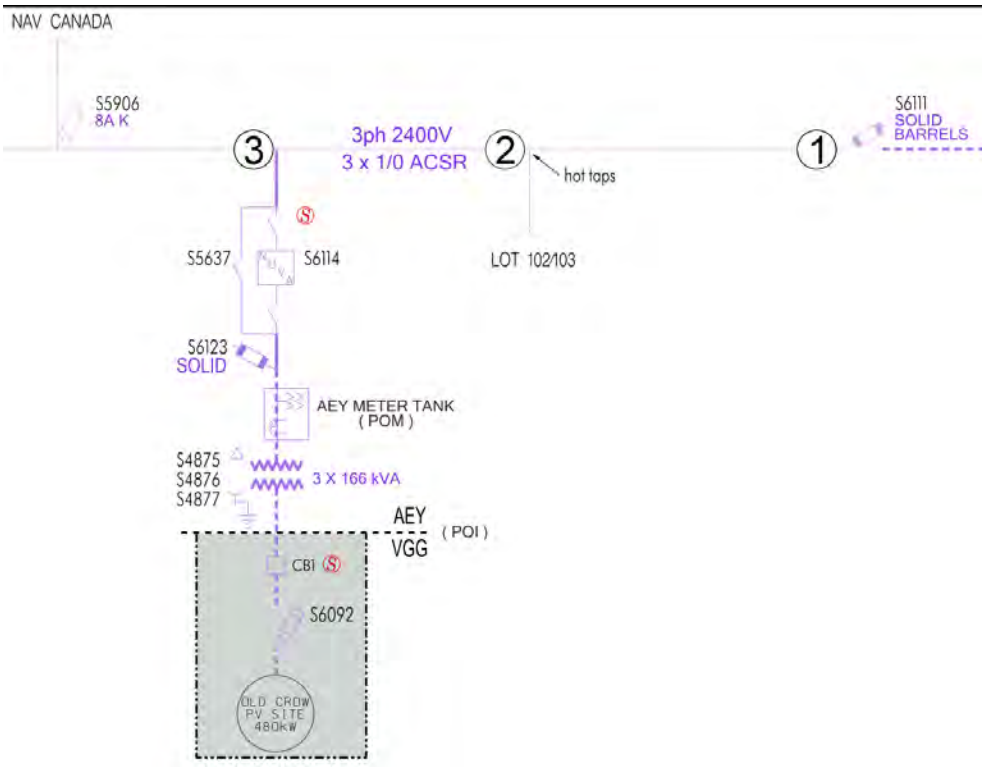
Alternative 1: One Regulator on 3L405

6. Three locations were considered for the placement of a single regulator on line 3L405. Refer to Figure 1. For both locations 1 and 2, the upstream voltage level will drop below 0.95 p.u. at 20 percent load growth. Location 3, outside of the solar array, gives the best performance with 40 percent room for load growth which is about 200 kW at the breaker.

Table 2: 3L405 Regulators

	Location 1	Location 2	Location 3
Worst Voltage A	0.96 p.u.	0.96 p.u.	0.99 p.u.
Worst Voltage B	0.98 p.u.	0.98 p.u.	1 p.u.
Worst Voltage C	0.97 p.u.	0.97 p.u.	0.99 p.u.
Distributed Load Growth Capacity from Breaker (Normal)	20% (102 kW)	20% (102 kW)	40% (207 kW)
End of Line Load to Break (Normal)	60 kW	60 kW	70 kW

Figure 1: 3L405 Regulator Locations



Alternative 2: One Regulator on 3L406

7. Without a regulator, there is room for 40 percent of load growth on line 3L406 during normal operation. The case for adding a regulator comes when the community is fed off the PV array and the BESS, which EA is off-diesel. During exclusively solar generation, the voltage levels along 5L406 are at 0.95 on the worst phase (the other two are at 0.98 and 0.98). One option to fix this issue would be to install a regulator at the

start of 3L406, either within the substation or just outside. Refer to Table 2 and Table 3 for the performance of this alternative.

Table 3: Existing Conditions During PV Generator

Worst Voltage A	0.98
Worst Voltage B	0.98
Worst Voltage C	0.95
Load Growth Capacity	10%

Table 4: Conditions During PV Generator w/Regulator

Worst Voltage A	1 p.u.
Worst Voltage B	0.99 p.u.
Worst Voltage C	0.99 p.u.
Load Growth Capacity	20%

Alternative 3: Rebalance 3L406

8. The model shows that Phase C is more loaded than both A and B along 3L406. Rebalancing this line alone will leave 15 percent room for load growth which will allow for reconductoring to be delayed for a few years.

9. Since phasing in the model may not be accurate the phasing of each connection should be field verified before undertaking this alternative.

Table 5: Rebalance 3L406

Worst Voltage A	0.97 p.u.
Worst Voltage B	0.99 p.u.
Worst Voltage C	0.98 p.u.
Load Growth Capacity	15%

Alternative 4: Reconductor and Rebalance 3L406

10. Rebalancing and reconductoring leaves 40 percent extra capacity on 3L406, which is in line with how much capacity is left after the regulator is put in on 3L405.

11. It is not imperative that the reconductor be done if the load balancing is optimized, but it will need to be done eventually.

Table 6: Conditions During PV Generator w/3L406 Reconductor and Rebalance

	Reconductor	Reconductor and Rebalance
Worst Voltage A	0.99 p.u.	0.99 p.u.
Worst Voltage B	0.99 p.u.	0.99 p.u.
Worst Voltage C	0.96 p.u.	0.99 p.u.
Load Growth Capacity	10%	40%

Alternative 5: Rebalance 3L405 East

12. The current model shows that Phase A is loaded much more than B and C. Table 6 compares rebalanced and existing conditions during PV only generation, which is the worst case. Rebalancing the load alone will not fix the existing voltage issue down this branch.

13. Since phasing on the model may not be accurate, field checks should be done to verify phasing on 3L405 East before rebalancing is done.

Table 7: Conditions During PV Generator w/3L405 East Rebalance

	Existing	Rebalance
Worst Voltage A	0.96 p.u.	0.96 p.u.
Worst Voltage B	0.98 p.u.	0.95 p.u.
Worst Voltage C	0.91 p.u.	0.94 p.u.
Load Growth Capacity	0%	0%

Alternative 6: Reconductor and Rebalance 3L405 East

14. This alternative explores increasing the size of the conductor to 1/0 up to S9609, including the tap towards the rink. Refer to Table 7 for the performance of increasing the conductor size. The simulations were run with PV only generation which represents the worst-case voltage.

Table 8: Conditions During PV Generator w/3L405 East Reconductor

	Existing Balance	Rebalanced per Alternative 4
Worst Voltage A	0.98 p.u.	0.99 p.u.
Worst Voltage B	1 p.u.	0.98 p.u.
Worst Voltage C	0.96 p.u.	0.97 p.u.
Load Growth Capacity	>5%	20% (43 kW)

Alternative 7: Two Regulators on 3L405

15. The purpose of exploring two regulators on line 3L405 is to boost the voltage in the reverse direction during PV only generation. During normal operation, a single regulator will suffice as can be seen in Alternative 1.

16. During the simulation of PV only generation with no regulators, it was noted that any voltage issues start downstream of where 3L405 East and 3L406 branch off so a common voltage regulator for these two lines will be unable to address the voltage issues.

Recommendation

17. It is recommended that Alternatives 1, 4 and 6 are undertaken to both fix existing voltage issues and leave significant room, 25 percent, for future load growth. In total, the work that would need to be completed is:

- Regulator addition downstream of the PV array;
- Reconductor and Rebalance 3L406; and
- Reconductor and Rebalance 3L405 East.

ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

6L19 Voltage Improvement

2023-2024 Business Case #30

Executive Summary

1. Voltages below AEY standard have been measured on the 35 kV system south of Whitehorse. This study is to identify possible solutions that alleviate the low voltage conditions on 6L11 and 6L19.

Background

2. Issues along the 35 kV system south of Whitehorse include low voltage conditions at Teslin and Robinson locations, and customers fed off the 35 kV system and the Lewes River regulators being tapped to their maximum limit for extended periods of time.

3. Low voltage conditions on a typical transmission line would not be an issue since the voltage can be stepped up at the distribution sub-stations. However, since the sub-transmission system feeds customers as well, the voltage on the sub transmission system will need to adhere to ATCO distribution voltage standards.

4. As can be seen in Figure 1, low voltage issues on the sub-transmission line are passing through to the distribution networks along 6L19. South McLintock, New Constabulary, Teslin Lake, and Teslin distribution networks. Refer to Table 1 for a summary of the voltages along 6L19 and the distribution networks fed off this line.

Figure 1: Existing Voltages on 6L11 and 6L19

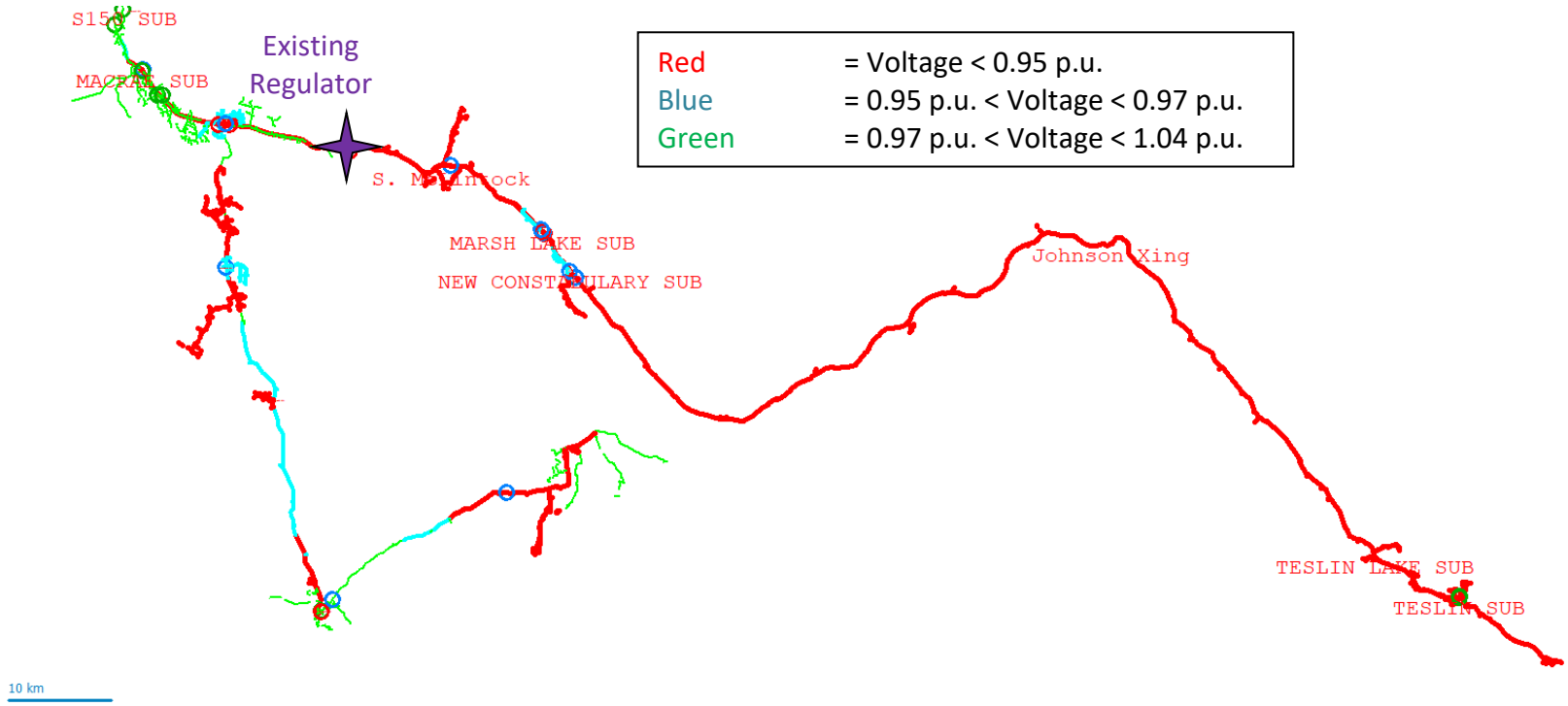


Table 1: Existing 6L19 Voltage and Current Summary

Location	Va (p.u.)	Vb (p.u.)	Vc (p.u.)	Ia (A)	Ib (A)	Ic (A)
McRae Sub (35 kV)	0.945	0.946	0.944	220.3	219.5	225.5
5L649 EOL	1.019	1.019	1.018	-	-	-
5L631 EOL	-	-	0.949	-	-	-
South McLintock Sub (35 kV)	0.932	0.946	0.934	54.7	45.0	64.0
5L611 EOL	-	-	0.926	-	-	-
Marsh Lake Sub (35 kV)	0.909	0.927	0.917	53.3	33.1	53.6
5L612 EOL	0.958	-	-	-	-	-
New Constabulary Sub (35 kV)	0.902	0.919	0.912	40.5	33.2	40.3
5L615 EOL	0.855	-	-	-	-	-
Johnson Crossing Sub (35 kV)	0.851	0.843	0.861	23.0	31.8	23.0
Teslin Lake Sub (35 kV)	0.819	0.796	0.828	22.4	29.6	22.5
4L301 EOL	-	0.802	-	-	-	-
Teslin Sub (35 kV)	0.812	0.787	0.821	20.7	24.4	19.2
5L613 EOL	0.879	-	-	-	-	-
5L614 EOL	-	0.868	-	-	-	-
Worst Voltage on 6L19	0.815	0.791	0.824	-	-	-
Carcross Cutoff	-	-	-	121.2	108.2	118.0

Project Description

5. AEY recommends a three-part approach to combat low voltage conditions along the 6L19 feeder. This project includes the following:

- Boosting the source voltage at S150 to 1.04 p.u.;
- Installing a new 200A regulator bank on the 6L11 feeder between Fireweed Dr. and Salmon Tr.;
- Relocating the 100A Carcross Cutoff to the Summit Lake area (approx. 5km West of Squanga Lake Campground); and
- Relocating the 100A Lewes River regulator to approximately 11 km downstream of its existing location, just before South McLintock Substation.

Project Schedule and Costs

Table 2: Project Schedule and Cost ($000)

	Cost	Target In-Service Date
Boost S150 Voltage to 1.04 p.u.	$0	2024
Install 200 A Regulator Bank on 6L11	$593	2024
Relocate 100 A Carcross Cutoff Regulator	$178	2024
Relocate 100 A Lewes River Regulator	$178	2024

Business Drivers and Benefits

6. This project will help alleviate low voltage conditions in Teslin, Robinson and other customers fed from the 35 kV system. Existing regulators will be able to perform within their regular range rather than operating at their maximum for extended periods of time. Improvements to voltage on the 35 kV system will overflow into downstream distribution networks that are also experiencing low voltage conditions due to upstream inadequacies.

Evaluation of Viable Alternatives

7. The ways to address low voltages on 6L19 include reconductoring, installing regulators, and adjusting the source voltage at S150. Many combinations of these

choices are possible and were investigated; however, in the interest of being concise only the following cases were considered:

- Install Two New Regulators on 6L11 and 6L19;
- Reconductor 6L11 and 6L19;
- Reconductor 6L11 and Install a New Regulator on 6L19;
- Boost S150 Voltage, Reconductor 6L11, Install Regulator on 6L19;
- Boost S150 Voltage, Relocate Two Reg Banks, and Install Regulator on 6L11; and
- Scenario 4 THELP: Install Regulator on 6L11, Install Regulator on 6L19.

Alternative 1: Install Two New Regulators on 6L11 and 6L19

8. This alternative explores installing two new three-phase regulator banks, one 400 A bank on 6L11 and one 100 A bank on 6L19. The additions of two regulator banks will mean there are four inline regulators between S150 and any distribution substation with a regulator along 6L19. This could pose the risk of overvoltage conditions during a load shedding event.

9. The location for the first regulator will be on 6L11 upstream of Macrae where voltage begins to dip below 0.95p.u. (between Miles Canyon Rd and Mt. Sima Rd). Once this regulator is installed, the model will be run, and the second regulator will be placed where the voltage drops below 0.97 on 6L19 (Squan Lake).

10. The two load shed events that have the risk for the highest voltage are the loss of Teslin sub and the opening of the Judas Creek recloser. During the loss of Teslin sub, the maximum voltage at the new 6L19 regulator is 1.164 p.u. This is below the long line rural maximum voltage of 1.167 p.u. During the opening of the Judas Creek recloser, the worst-case voltage will occur on 5L613 in Teslin with a voltage of 1.099 p.u. This is also within the acceptable range for over voltage.

Figure 2: Alternative 1 Voltage Conditions

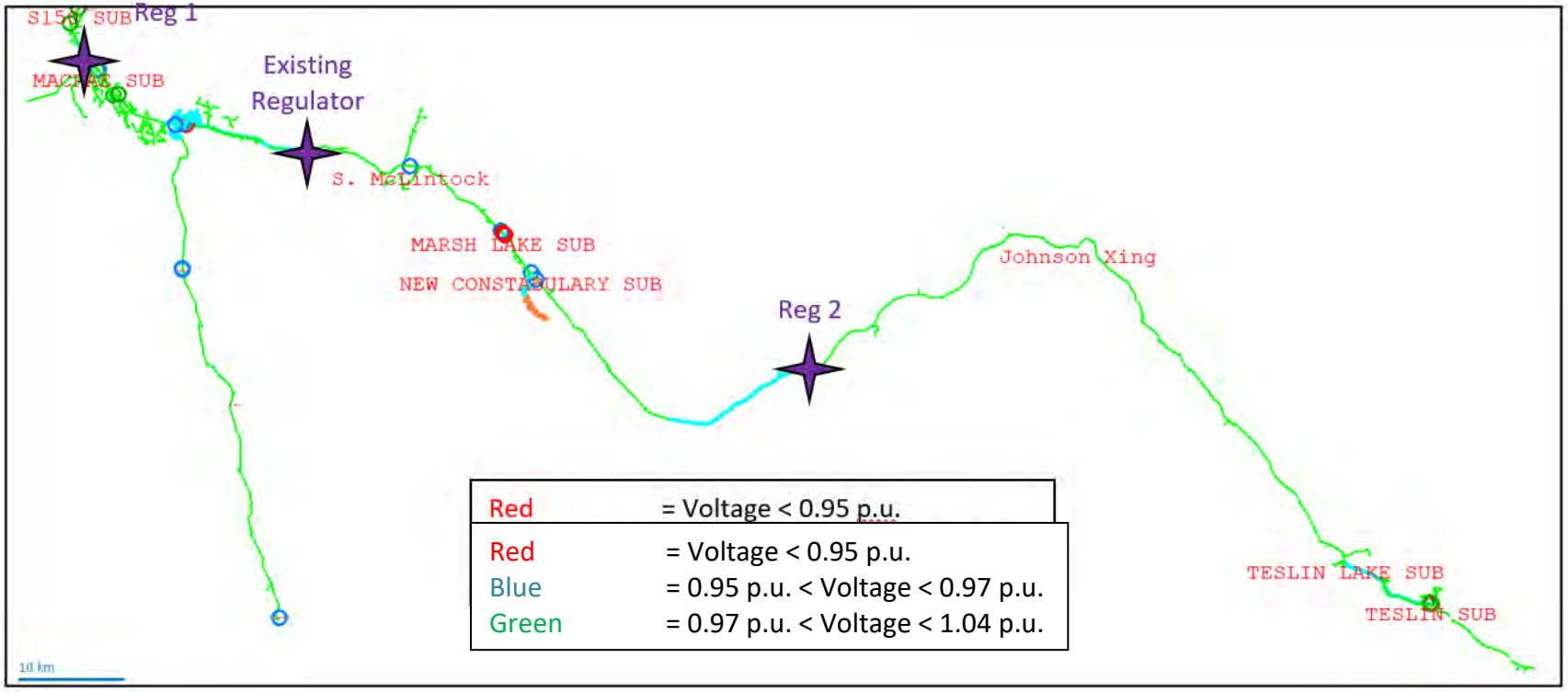


Figure 3: Alternative 1 Regulator 1 Location SLD

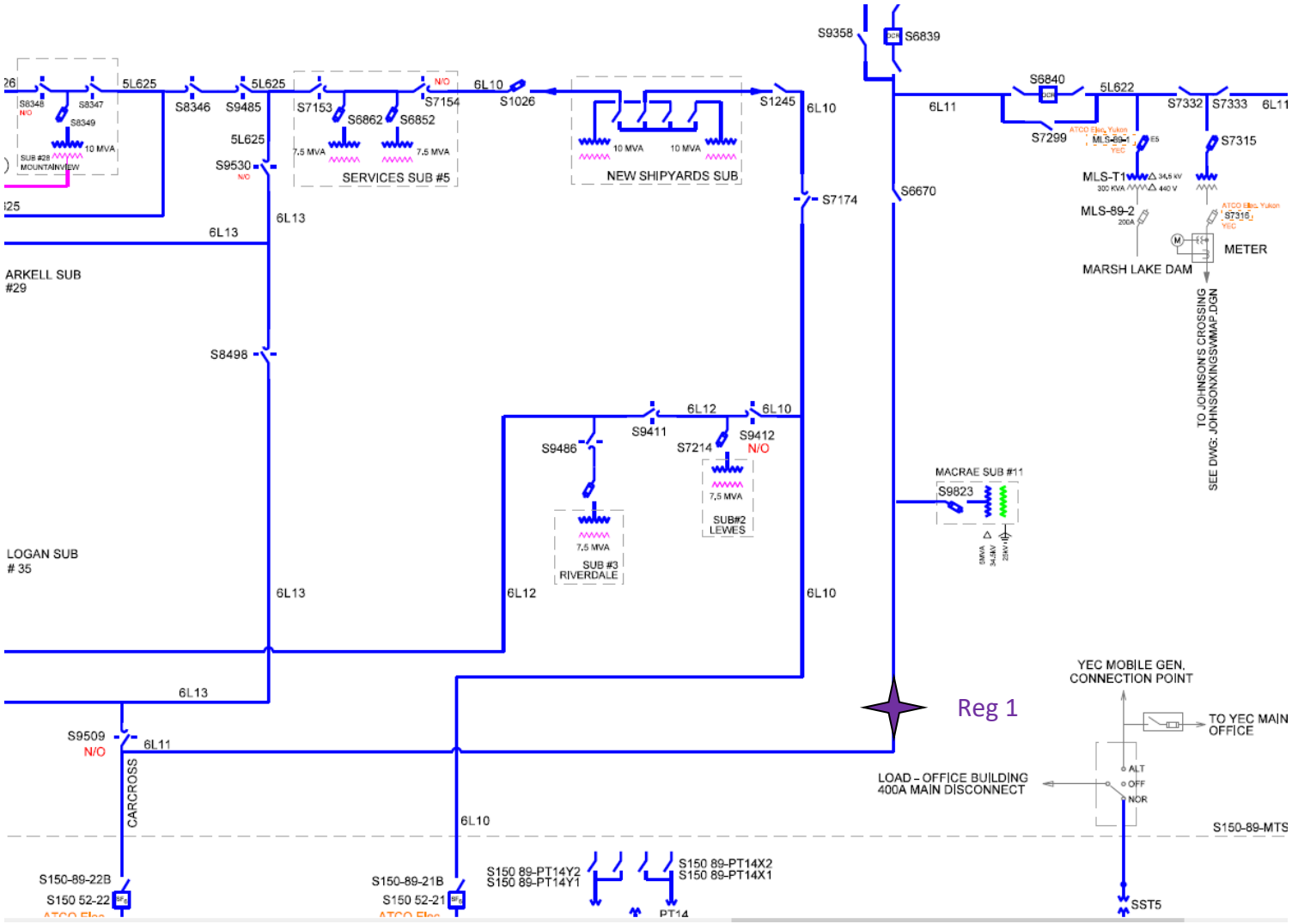
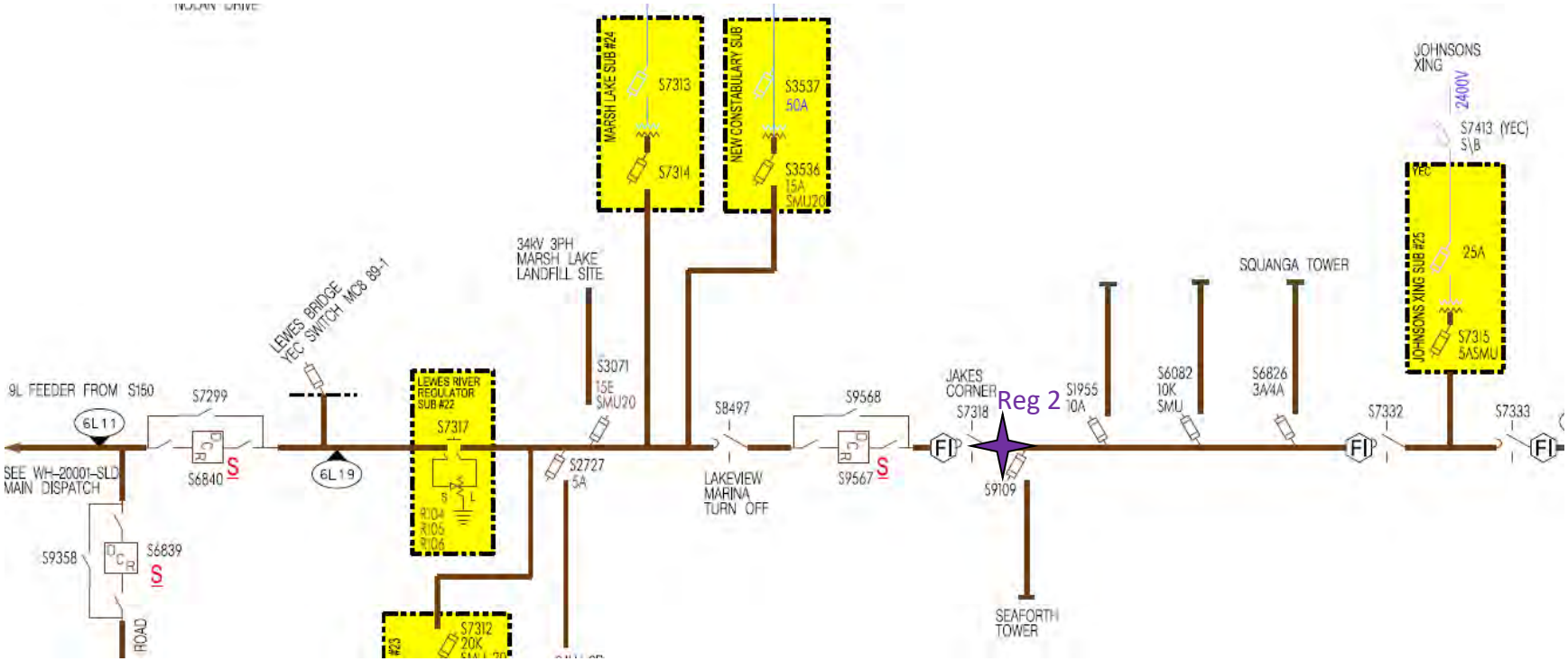


Figure 4: Alternative 1 Regulator 2 Location SLD



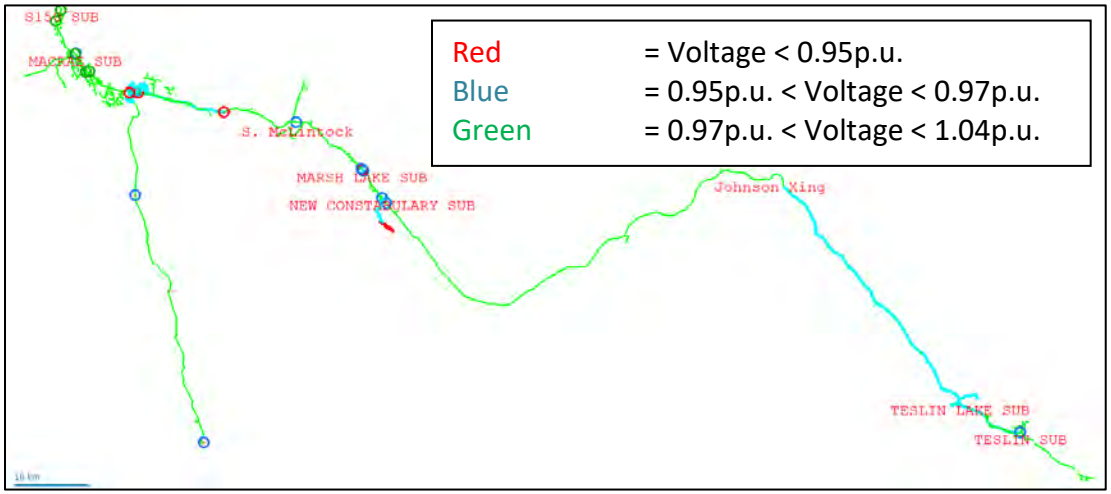
Alternative 2: Reconductor 6L11 and 6L19

11. This alternative explores reconductoring the entirety of 6L11 and 6L19 with 477 ACSR (158 km in total). Anything less than this results in voltage below 0.95 p.u. on 6L19 close to Teslin during existing conditions which impacts 35 kV customers.

12. This amount of reconductoring will be very expensive, so the following alternatives explore a combination of reconductoring and installing voltage supporting equipment.

13. This alternative allows for future a regulator addition which would greatly increase system capacity and further improve voltages in the Teslin area.

Figure 5: Alternative 2 Voltage Conditions



Alternative 3: Reconductor 6L11 and install a new regulator on 6L19

14. This alternative explores reconductoring all of 6L11 with 296 ACSR and installing a new regulator on 6L19 to boost the end of line voltage.

15. The location for the regulator was chosen to be where the voltage is below 0.97 but is still above 0.95 after the reconductor.

Figure 6: Alternative 3 Voltage Conditions

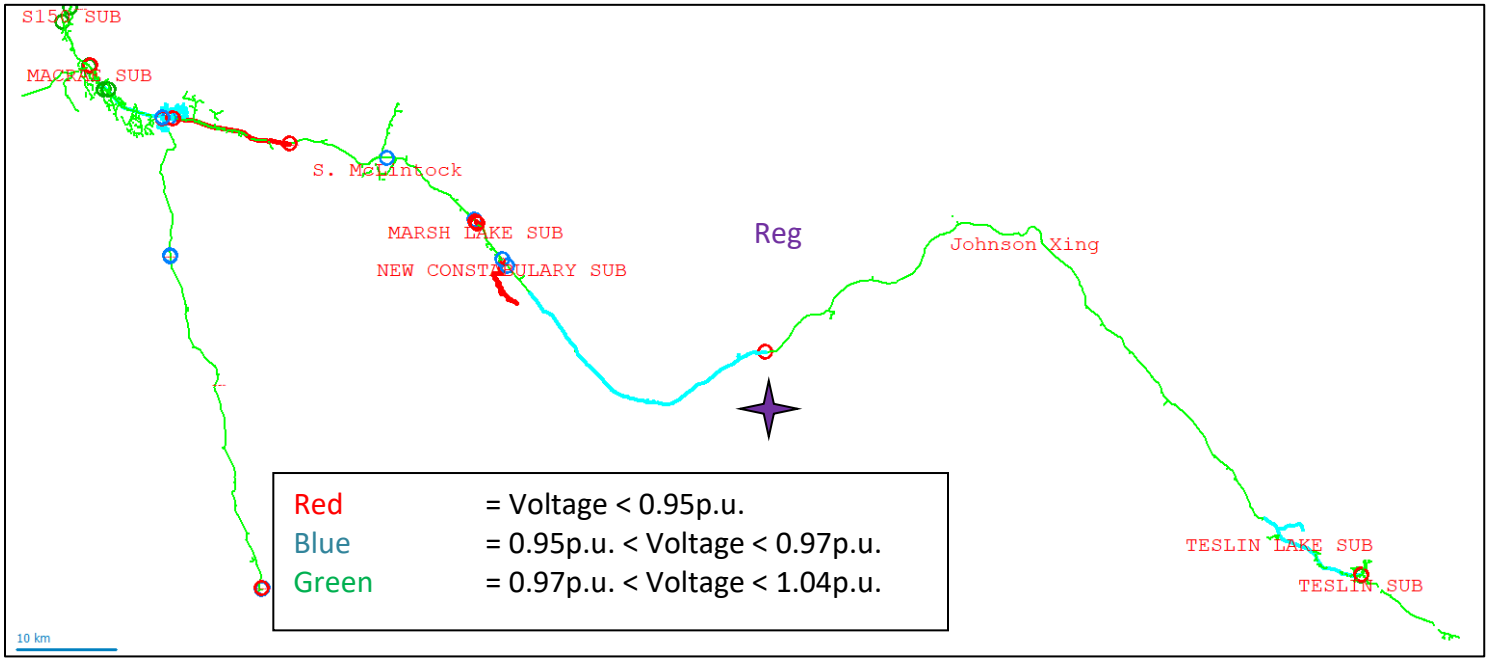
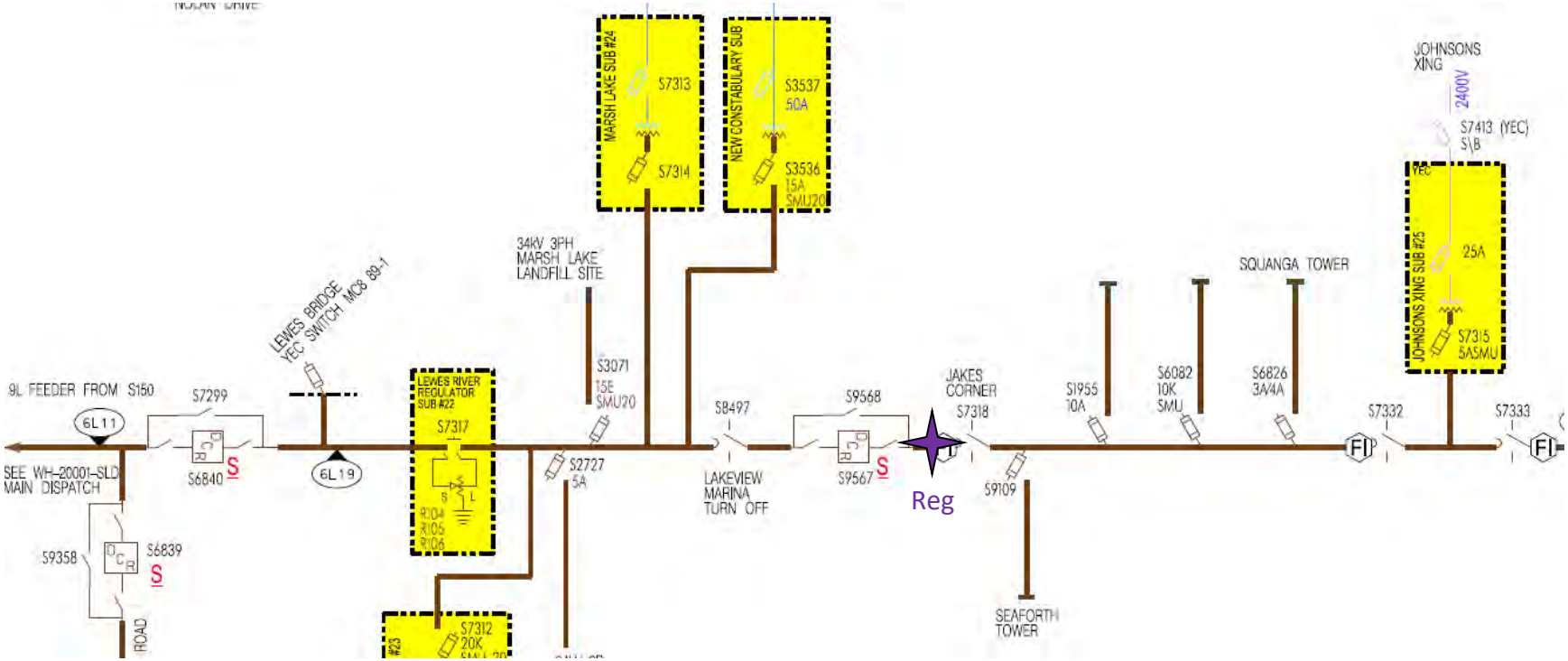


Figure 7: Alternative 3 Regulator Location SLD

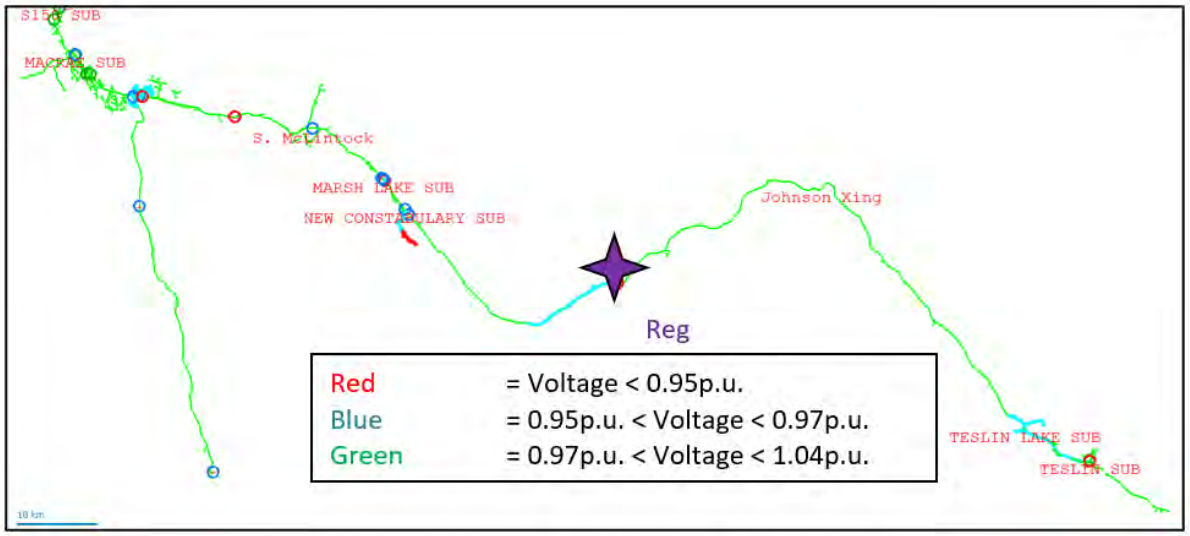


Alternative 4: Boost S150 Voltage, Reconductor 6L11, Install Regulator on 6L19

16. This alternative explores increasing the S150 voltage to 1.04 p.u., reconductoring 6L11 using 477 ACSR and installing a new regulator along 6L19. This is a similar approach to Alternative 1, but instead of using a regulator to increase 6L11 voltage, the voltage will be increased at substation S150. The regulator was placed in the same methodology as in Alternative 1.

17. This alternative would immediately address the voltage issue all along 6L11 and 6L19 with issues arising at McRae and New Constabulary after five years. The issue after five years at MacRae can easily be addressed by relocating the single-phase regulator further upstream, and the issues at New Constabulary can be fixed by installing a single-phase regulator at the substation.

Figure 8: Alternative 4 Voltage Conditions



Alternative 5: Boost S150, Relocate Two Reg Banks, and Install Regulator on 6L11

18. This alternative relocates existing regulators on the system to better align with system demand, while lowering costs by reusing assets versus buying new ones. Two regulator banks will be relocated to within the 6L19 line, while a new 200A regulator bank will be installed on 6L11.

19. The location for the new 200A regulator will be on 6L11 upstream of Macrae where voltage begins to dip below 0.95p.u. (between Fireweed Dr. and Salmon Tr.). The 100A Lewes River regulator bank will be relocated approximately 11km downstream, just before South McLintock substation. Lastly, the 6L18 Carcross Cutoff 100A reg bank will be relocated to the Summit Lake area (approx. 5 km West of Squanga Lake Campground).

20. The three load shed events that have the risk for the highest voltage are the loss of Teslin sub, the opening of the Judas Creek recloser, and the opening of the 6L18 Carcross Cutoff recloser. During the loss of Teslin sub, the maximum voltage at the new 6L19 regulator is 1.152 p.u. This is below the long line rural maximum voltage of 1.167 p.u. During the opening of the Judas Creek recloser and the Carcross Cutoff recloser the worst-case voltage will occur on 5L613 in Teslin with a voltage of 1.095 p.u. and 1.094 p.u. respectively. This is also within the acceptable range for over voltage.

Figure 9: Alternative 5 Voltage Conditions

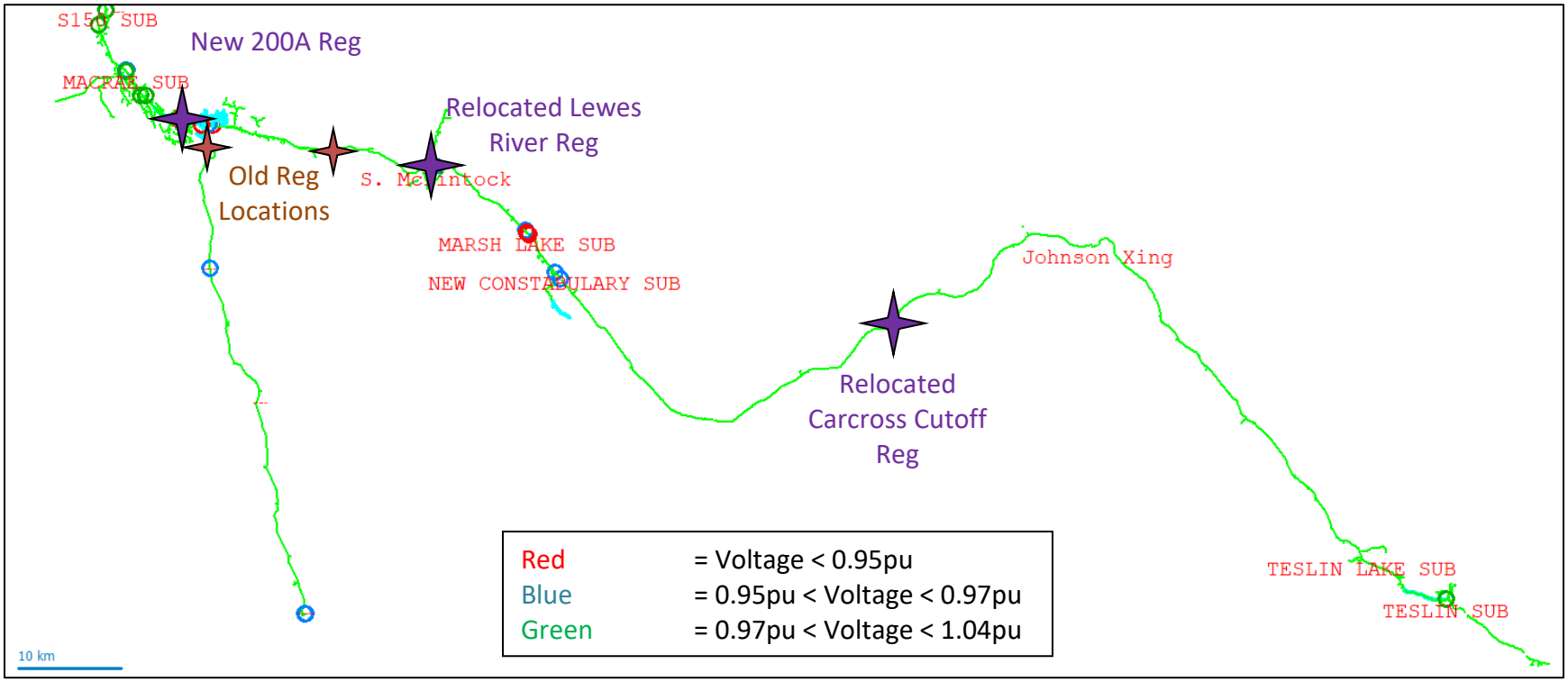


Figure 10: Alternative 5 Regulator Re- Location

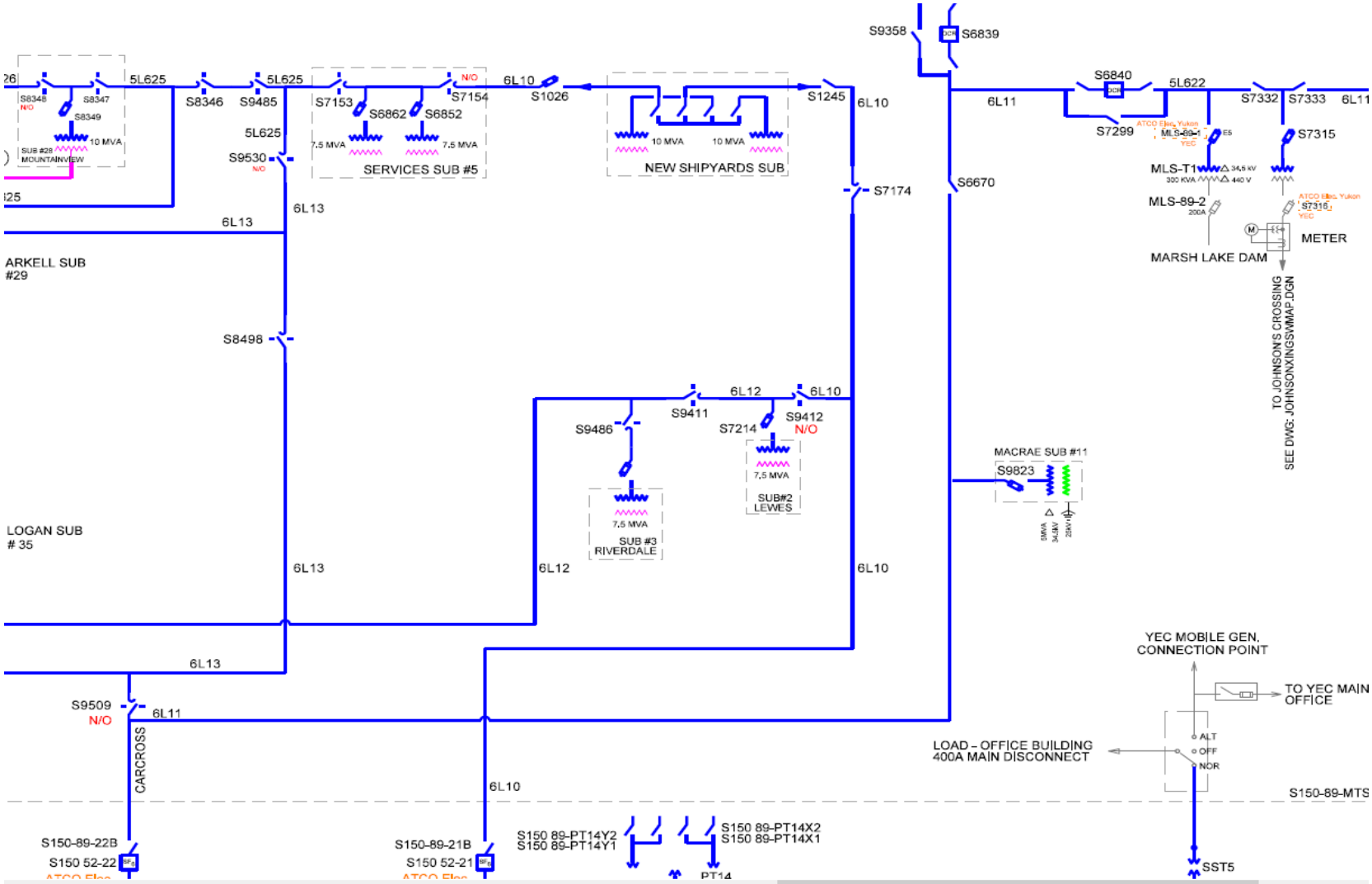
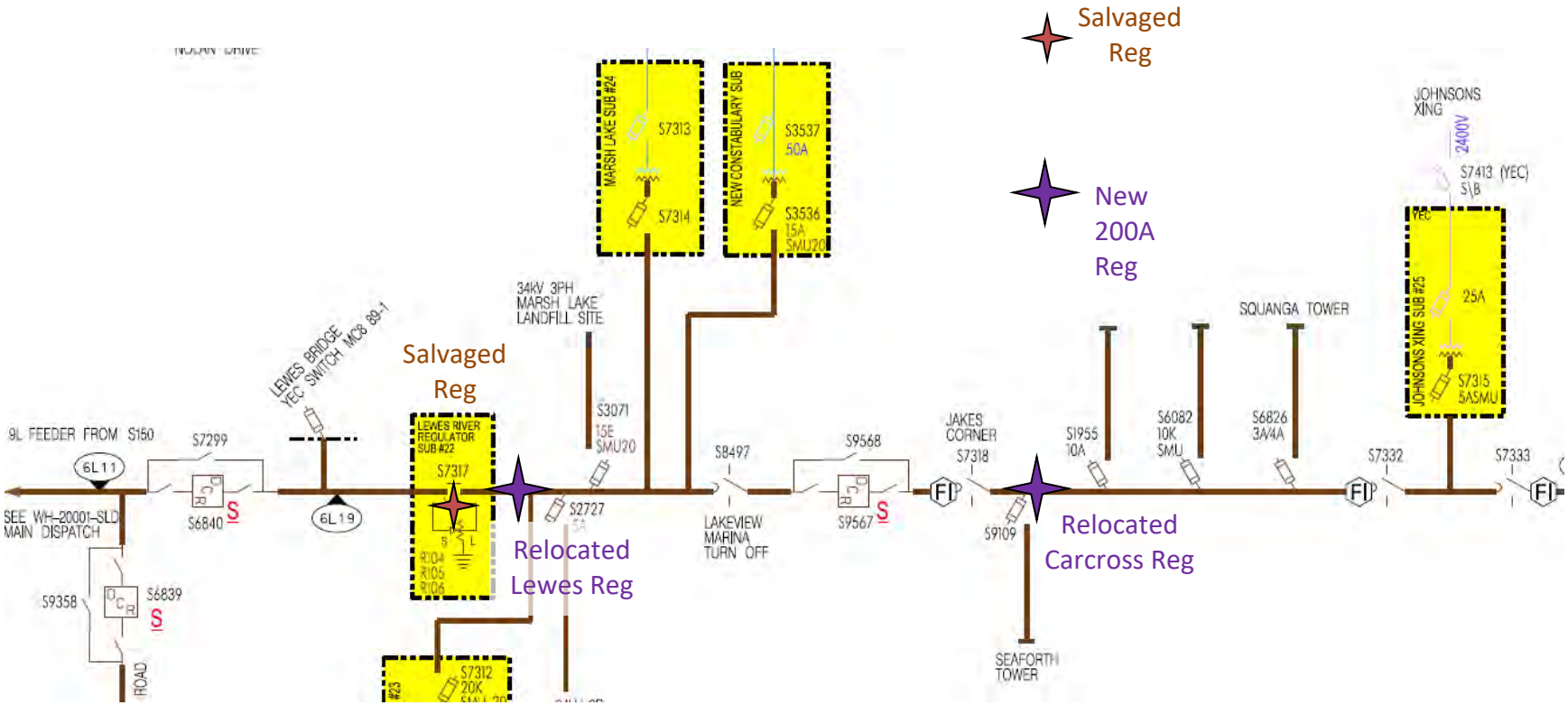


Figure 11: Alternative 5 Regulator Re- Location Layout



Alternative 6: Scenario 4 THELP: Install Regulator on 6L11, Install Regulator on 6L19

21. This alternative is the exact same as Alternative 1; however, the regulators will be installed at the locations specified by the THELP project.

22. The two load shed events that have the risk for the highest voltage are the loss of Teslin sub and the opening of the Judas Creek recloser. During the loss of Teslin sub, the maximum voltage at the new 6L19 regulator is 1.121 p.u. This is below the long line rural maximum voltage of 1.167 p.u. During the opening of the Judas Creek recloser, the worst-case voltage will occur on 5L613 in Teslin with a voltage of 1.091 p.u. This is also within the acceptable range for over voltage.

Figure 12: THELP Regulator Placement SLD

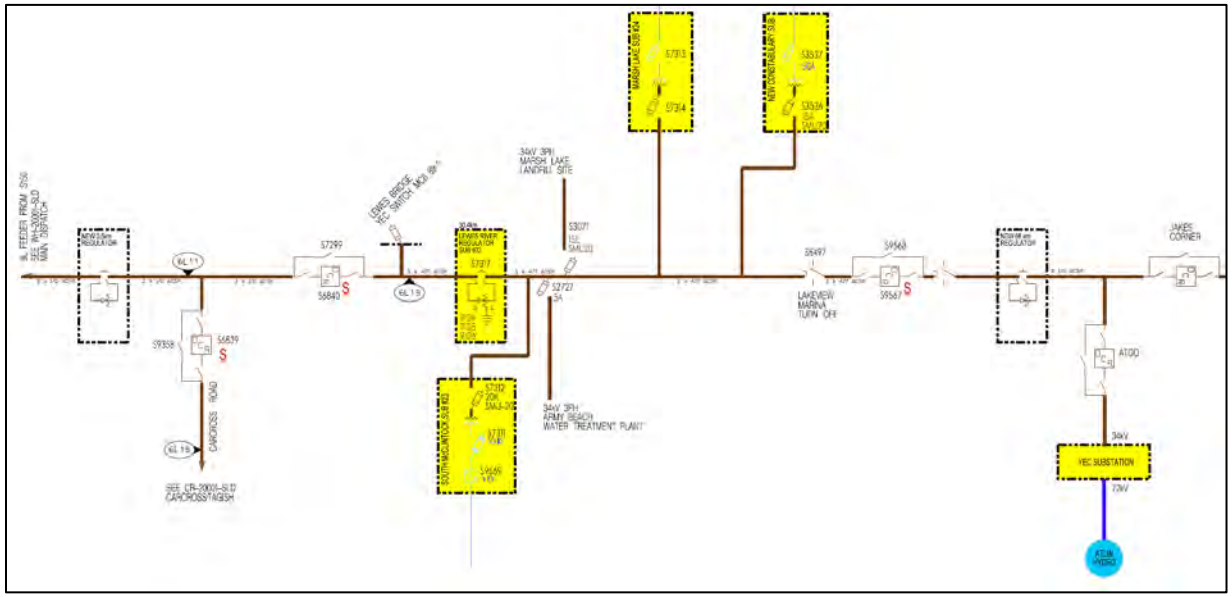
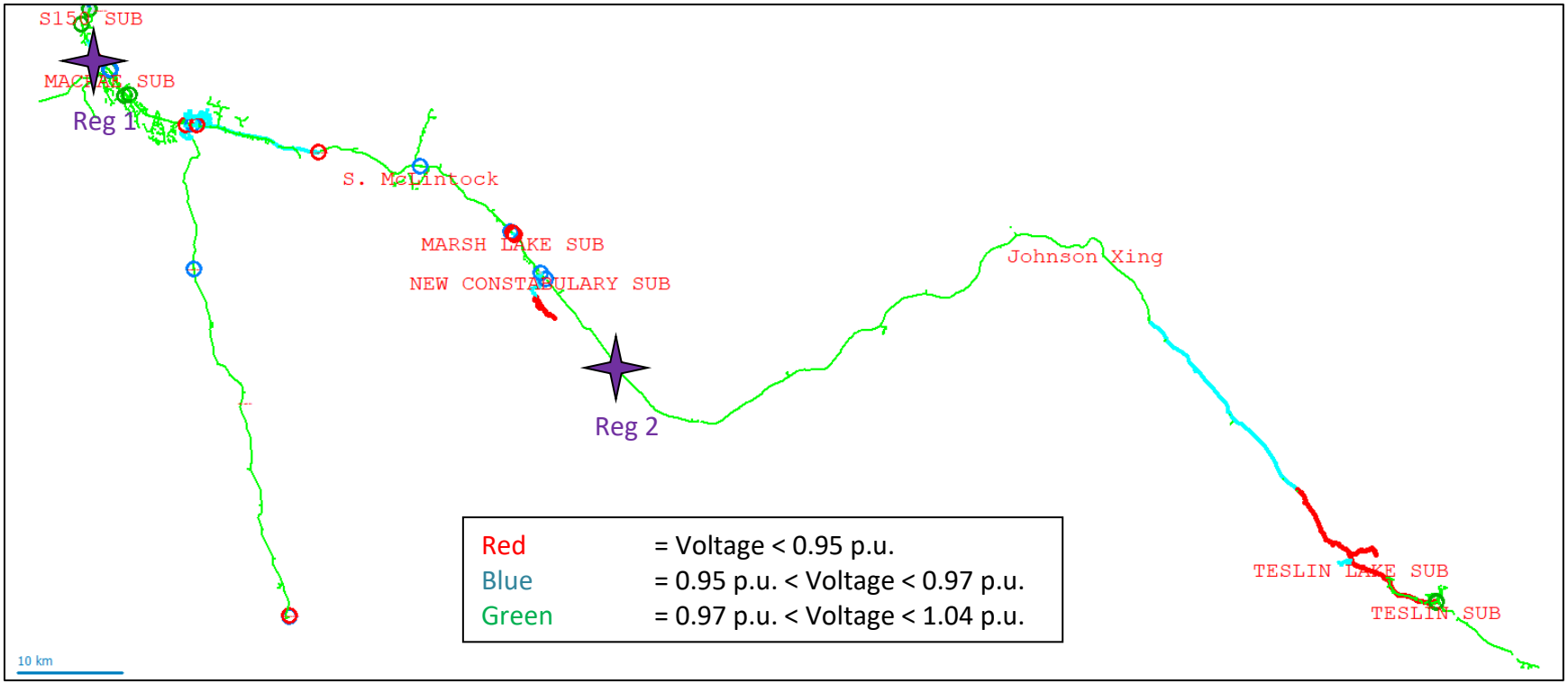


Figure 13: Alternative 6 Voltage Conditions



Recommendation

23. Alternative 5 is the recommended alternative as it immediately solves the 35 kV low voltage issues for the entire 6L11 and 6L19 line without any need for reconductoring and can benefit from cost savings through relocating two 100 A regulators versus buying new ones. This alternative also performs the best in the year 2028 and is the only alternative that addresses the low voltage conditions on the 25 kV New Constabulary distribution system.

Appendices

Appendix A Overview of Voltage Conditions per Alternative

Appendix A: (Overview of Voltage Conditions per Alternative)

Existing			
Location	**Va**	**Vb**	**Vc**
McRae Sub (35 kV)	0.942	0.944	0.942
5L649 EOL	1.015	1.015	1.014
5L631 EOL	-	-	0.943
South McLintock Sub (35 kV)	0.924	0.939	0.926
5L611 EOL	-	-	0.918
Marsh Lake Sub (35 kV)	0.9	0.918	0.909
5L612 EOL	0.946	-	-
New Constabulary Sub (35 kV)	0.893	0.91	0.903
5L615 EOL	0.844	-	-
Johnson Crossing Sub (35 kV)	0.839	0.831	0.849
Teslin Lake Sub (35 kV)	0.805	0.781	0.814
4L301 EOL	-	0.787	-
Teslin Sub (35 kV)	0.798	0.772	0.807
5L613 EOL	0.862	-	-
5L614 EOL	-	0.85	-
Worst Voltage on 6L19	0.798	0.772	0.807

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**
1.023	1.025	1.029	0.983	0.984	0.983	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	1.030	1.033	1.031	1.030	1.030	1.031	1.030	1.029	1.032	1.031	1.031	1.030	1.029	1.029	1.033	1.030	1.033
-	-	0.963	-	-	0.966	-	-	0.959	-	-	0.961	-	-	0.958	-	-	0.963
1.018	1.014	1.015	1.013	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
-	-	1.001	-	-	1.001	-	-	0.993	-	-	1.002	-	-	1.024	-	-	1.001
0.997	0.996	1.001	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
0.997	-	-	0.993	-	-	0.992	-	-	0.992	-	-	0.994	-	-	0.990	-	-
0.992	0.989	0.997	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
0.947	-	-	0.949	-	-	0.931	-	-	0.948	-	-	0.968	-	-	0.946	-	-
1.017	1.009	1.022	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
0.991	0.970	0.995	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
-	0.974	-	-	0.958	-	-	0.972	-	-	0.969	-	-	0.975	-	-	0.951	-
0.985	0.963	0.989	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
1.038	-	-	1.027	-	-	1.033	-	-	1.030	-	-	1.033	-	-	1.028	-	-
-	1.032	-	-	1.025	-	-	1.026	-	-	1.024	-	-	1.030	-	-	1.016	-
0.954	0.968	0.955	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

ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Whistle Bend Subdivision

2023-2024 Business Case #31

Executive Summary

1. This project will design and build an Electrical Distribution System to service Stage 7B and Stage 9A of the Whistle Bend Subdivision in Whitehorse in compliance with the YUB approved terms and conditions for electrical service.

2. This is new construction and is fully contributed other than the Board approved $1,240 per streetlight.

Background

3. Whistle Bend Subdivision is planned to be Whitehorse's largest residential subdivision with room for 8,000 residents. Plans include future schools, retail shops, town square and parkland.

4. Development of the Whistle Bend Subdivision began in 2006 under a joint agreement by the City of Whitehorse and the Government of Yukon. The Government of Yukon has developed all stages so far (1-6) and will also complete development of Stage 7B and Stage 9A in 2023.

5. AEY has been planning the orderly development of electrical infrastructure in the area to meet the present and future demands of this large subdivision. Whistle Bend Substation was completed in 2012 in large part to serve this growing area. AEY has plans for both high-capacity feeders and low capacity feeders to appropriately meet the subdivision's electrical needs.

6. The high-level electrical plan created for the area by AEY can be seen in Appendix A.

Project Description

7. This project will engineer, procure, and install:

- High voltage cable;
- Low voltage cable;
- Duct systems for cables;
- Transformers;

- Pad mounted switching devices;
- Low voltage pedestals; and
- Streetlights.

8. Detailed engineering is being coordinated with the Yukon Government, the City of Whitehorse, their consultants and with NWTel.

Project Schedule and Cost

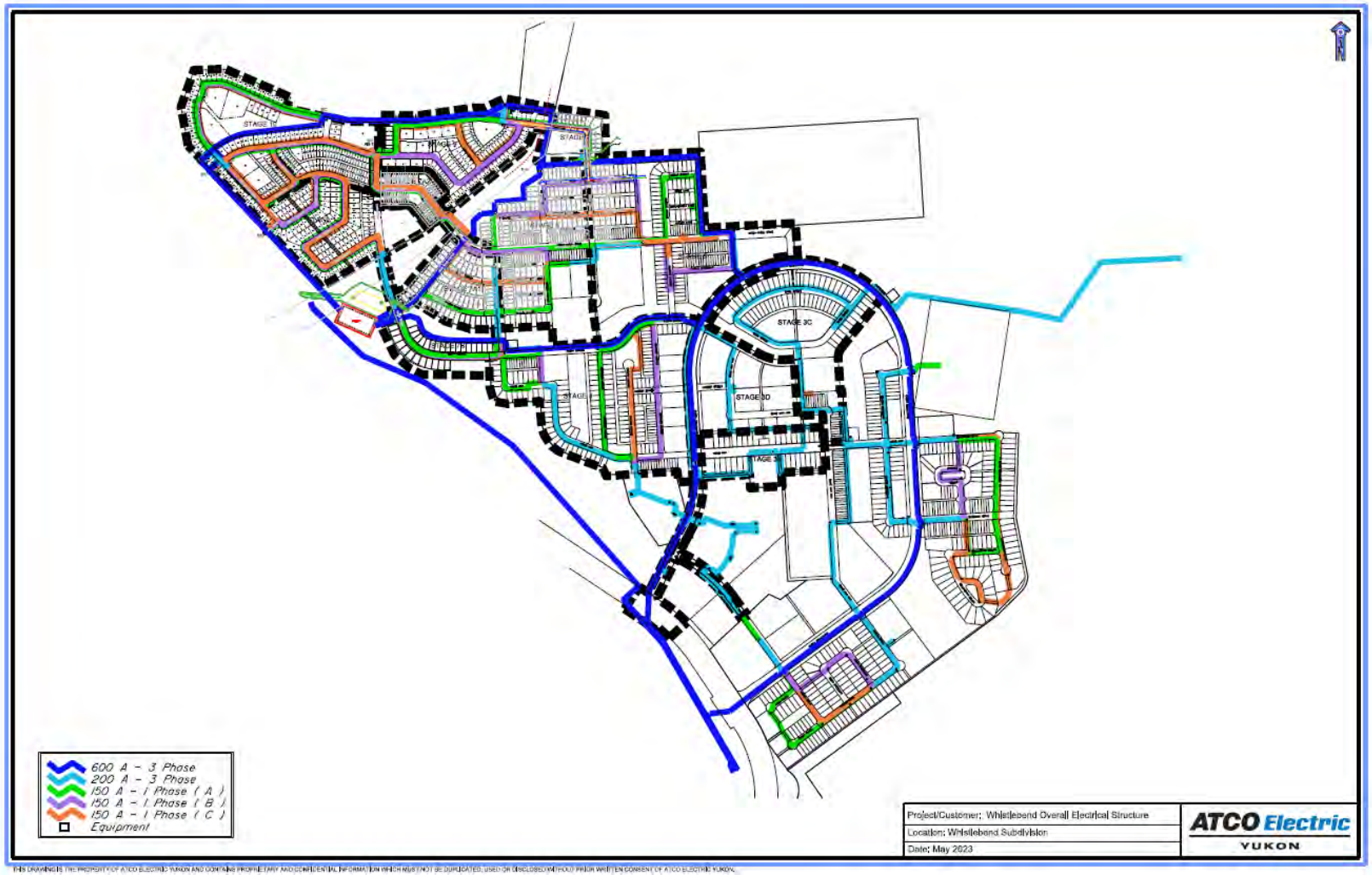
Table 1: Project Costs and Schedules ($000)

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

Appendices

Appendix A Whistlebend Subdivision

Appendix A: Whistlebend Subdivision



ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Fish Lake 1 Roof Replacement

2023-2024 Business Case #32

Executive Summary

1. Remedy leaking roof by constructing a new roof and ventilated attic over the existing roof at Fish Lake 1. This site houses a hydro turbine generator with associated control equipment.

Background

2. Despite numerous repair attempts, the current roof continues to leak, putting the controls and operational equipment at risk.

Project Description

3. Construct a new penetration free roof over the existing roof, utilizing the existing roof as the building envelope, and creating an insulated and ventilated attic space between the roofs. This will provide a leak-free, reliable, and durable roof for the facility with minimal disruption to ongoing operations.

Project Schedule and Cost

Table 1: Project Schedule and Cost
($000)

	Estimated Date	Budgeted Cost
Building Design	2022	59
Engineering Support During Construction	September 2023	35
Construction	September 2023	417
Total Budgeted Cost		511

Business Drivers and Benefits

4. The need to protect equipment and operational equipment from potential water damage.

Evaluation of Viable Alternatives

Alternative 1

5. Repairing the roof. This has been attempted numerous times and has failed to fix the leak.

Alternative 2

6. Replacing the roof with a similar roof. This would not necessarily solve the leak problem on a long-term basis. Additionally, the need to dispose of the old roof and the major disruption to plant operations this would entail make this alternative less desirable.

Recommendation

7. To ensure a long-term fix to the leaking roof and to minimize disruption to plant operations we recommend constructing a new roof over the existing roof creating a leak proof roof.

ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Louise Lake Auxiliary Structure Replacement

2023-2024 Business Case #33

Executive Summary

1. AEY, in compliance with Yukon Water Board water use license HY12-065, is planning to replace the Louise Lake Auxiliary Spillway structure within the Fish Lake hydro system. The structure is required to handle the Inflow Design Flood based on the Canadian Dam Safety guidelines. A recommendation to replace the aging structure was received within the 2015 Dam Safety Report by Northland Earth and Water. The existing wooden structure was built in 1990 and is beyond its serviceable life span. As the structure is crucial for flood management, public safety and protection of both public and downstream AEY infrastructure, the replacement is a priority. It is recommended that the structure be replaced.

Background

2. The auxiliary spillway is an overflow spillway structure set in an earth fill dike that dams a former channel from Louise Lake to Franklin Lake at the northwest corner of the main arm of Louise Lake. Flows released from this structure leave the water shed used for the hydro system and cannot be used for generation.

3. The existing structure was built in 1990 and consists of an 11.2 metres long, 2.1 metres deep, and 2.7 metres wide wooden flume. The entrance to the flume is equipped with two stop-log bays for placing and holding 100 mm wide by 200 mm high timber stop-logs.

4. The spillway was identified within the 2012 Dam Safety Report as showing signs of age and wear. In 2013 a more comprehensive review of the structure was performed by Northland Earth & Water Consulting and a recommendation to undertake planning for rehabilitation or replacement of this structure by 2020 was provided. Over the next three years minor repairs, maintenance, surveys, and draft designs were conducted in compliance with the recommendation. However, in 2016 the annual Dam Safety Report noted the deterioration was advancing and that rehabilitation of the structure was no longer viable and a recommendation to replace was issued. As such Northwest Hydraulic Consultants (NHC) was contracted to design a replacement spillway structure.

5. Also in 2019, AEY contracted Morrison Hershfield to perform an external Dam Safety Review of the entire Fish Lake hydro system. A resulting recommendation was that AEY conduct an updated dam breach study with the intent to revise the dam classification to a minimum of 'significant' (from low), review the Inflow Design Flood (IDF) and discharge capacity of Fish Lake control structure, Louise Lake, Headpond 1 and 2. AEY received this report in May of 2020.

6. Design constraints for the replacement Louise Lake Auxiliary Structure will be based on the outcome of the IDF review and dam breach study. As a result, the design of the replacement structure was halted at the draft stage in 2020.

7. A review of the IDF was done in 2021-2022 by Northland Earth & Water. NHC will use this new IDF flow data and conduct a dam breach study and assign dam classifications as required in 2022-2023. The outcome will allow the design of the replacement spillway structure to continue with new design constraints.

Project Description

8. The scope of the project includes finalizing the draft design and detailed cost estimate as well as removal of the old spillway structure and construction of the new spillway structure.

Project Schedule and Cost

9. Table 1 below provides an estimated milestone schedule for the project:

Table 1: Project Timetable

Milestone	Completion Dates
Finalize Design	Q2, 2024
Construction Tender & Award	Q2, 2024
Complete Construction	Q4, 2024

10. The timing of the build assumes the dam breach study will be completed and the design can be updated by end of March 2024.

11. It is also assumed water inflows in 2024 will be at or below normal. In the event it is a high inflow year, the risk is too high to decommission the spillway structure during a period we may have to use it. Pursuant to the water license, the spillway must be available for use in the event of high inflow. To do the work required to replace the spillway requires blocking the spillway. If the water is too high, AEY will have to delay the work until suitable conditions are present. Additionally, this structure is a failsafe that protects Fish Lake 1 and 2 from excessive water flow and damage to valuable water turbines and generating equipment. The structure also ensures that Louise Lake residents do not experience excessive flooding.

12. Table 2 below, details the costs of the project based on similar control structures built in 2018 (Headpond 2 Spillway) and 2020 (Unit No. 1 Diversion Structure):

Table 2: Project Costs
($000)

Year	Description	Cost
Prior to test period	Design	52
2023	Design	1
2024	Design, Tender, and Construct	$773
Total		**$826**

Business Drivers and Benefits

License Compliance

In compliance with condition 19 of water use license HY12-065, *all works associated with the license shall be constructed and maintained by the Licensee in good order, consistent with sound engineering and environmental practices*. Based on the annual dam safety review (condition 42) done in 2015 by Northland Earth and Water and 2019 by Morrison Hershfield, the condition of the structure is beyond rehabilitation and both inspections recommended the structure be replaced. The 2019 report identifies replacement should occur within two years.

Safety

13. The structure is a key component during a flood event to ensure the residential properties along the shoreline of Louise Lake and their residents are not exposed to flood waters.

Operations

14. Since the completion of Ditch No. 3 Diversion in 2016, the Louise Lake Auxiliary structure is no longer required to be used during routine operations. However, it remains a key structure for flood management. Operational procedures, as a requirement of the Water License, in a flood event require Ditch No. 2 to be restricted to minimum outflows (minimizing water towards our downstream hydro facilities), and all remaining flows are handled by the Louise Lake Auxiliary structure to remove the flood waters from the waterways feeding our downstream hydro facilities.

Evaluation of Viable Alternatives

15. Given the structure is required to handle the Inflow Design Flood based on the Canadian Dam Safety guidelines and it was determined through the dam safety review (performed in 2016) that rehabilitation is no longer viable, this was the only feasible alternative.

Recommendation

16. Proceed with replacing the current structure.

2023-2024 General Rate Application (GRA)

Yukon Government Robert Campbell Highway Streetlights

2023-2024 Business Case #34

Executive Summary

1. The Yukon Government has requested streetlighting and underground supply cables to be installed from km 1 to km 4 on the Robert Campbell Highway near Watson Lake.

2. This is a Customer-Driven Streetlight Project. AEY has an obligation to serve customers with electrical supply and streetlighting.

Background

3. AEY is the electrical generation, distribution, and streetlighting provider in Watson Lake. The project will be invested in at the Board approved rate of $1,240 per light with the remainder of the project cost contributed by the customer.

4. The overall project map can be seen in Appendix A.

Project Description

5. The project scope is as follows:

- 54 streetlights including bases, steel poles, and LED heads;
- 3000 metres of trenching and conduit;
- 3200 metres of cable to be installed; and
- Electrical sources for the streetlights.

Project Schedule and Cost

6. The in-service date is scheduled for December 2023. The AEY investment is based on the Board approved rate of $1,240 per streetlight.

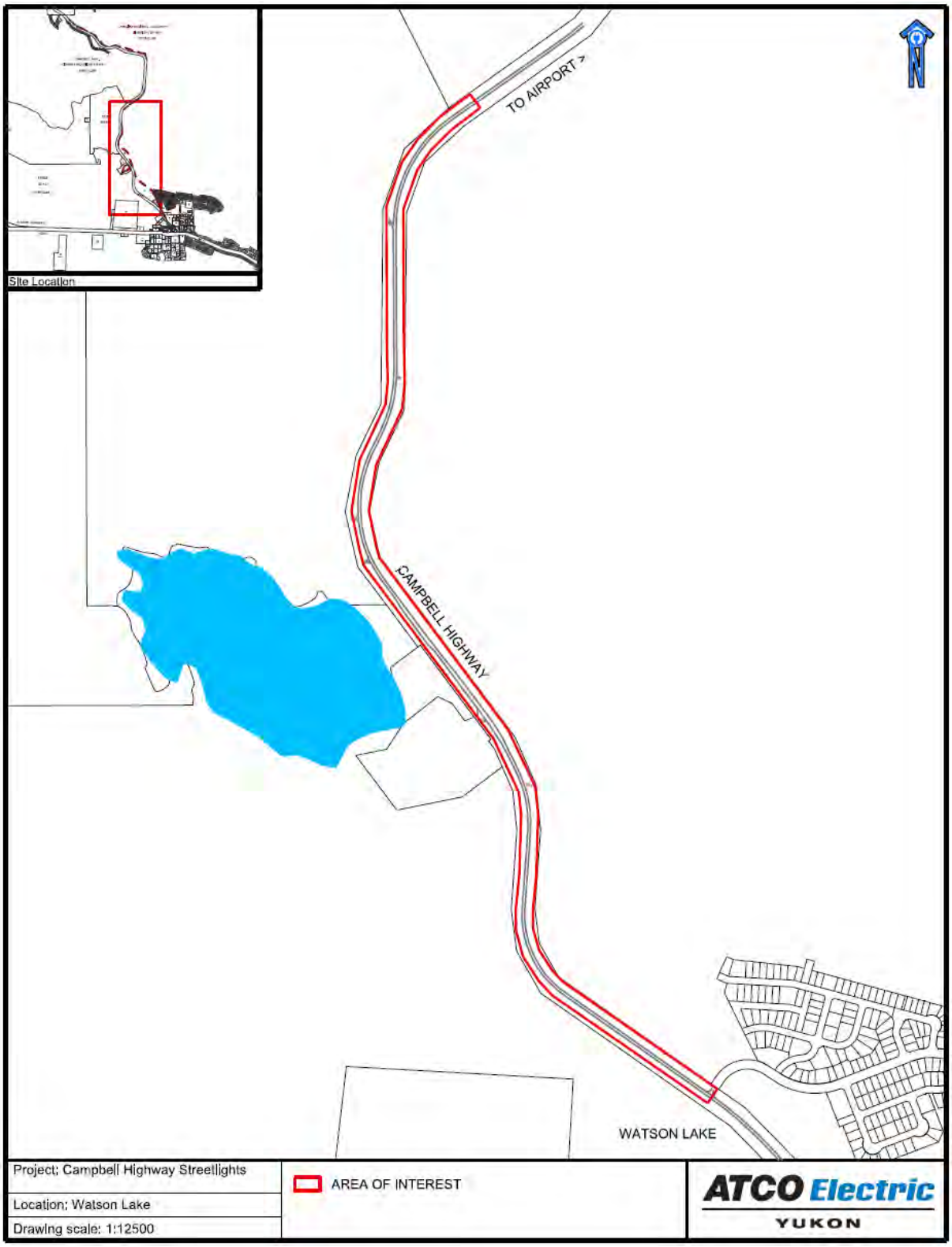
Table 1: Project Schedule and Costs
($000)

Material	350
Labour (construction, PM, engineering, commissioning)	557
Contribution	(773)
AEY Investment	**67**

Appendices

Appendix A Robert Campbell Highway

Appendix A – Robert Campbell Highway



2023-2024 General Rate Application (GRA)

ArcticPharm Yukon's Independent Power Production (IPP) Site

2023-2024 Business Case #35

Executive Summary

1. ArcticPharm is constructing a 2 MW photovoltaic Yukon's Independent Power Production (IPP) site. This IPP Project will require upgrades to the AEY Distribution System.

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.

3. This is a fully contributed Customer-Driven Interconnection Project. AEY has an obligation to serve customers in with electrical supply.

Background

4. This Project is part of the Standard Offer Program (SOP) for IPP policy.

5. AEY needs to complete upgrades to the 25kv distribution system to allow the connection of this IPP Project. Construction is scheduled to begin in June 2023 and finish in July 2023.

6. The overall project map can be seen in Appendix A.

Project Description

7. The most recent YEC Feasibility Study determined the AEY distribution system upgrade scope to accommodate the export increase of the distributed energy resource:

(1) 2.7 km single phase line salvage and rebuild to 1/0 ACSR three-phase;
(2) New three-phase tap comprised of;
    (a) 400 m 1/0 ACSR.
    (b) 38 m 1C1 underground cable.
(3) Three-phase interrupting device + SCADA capability at IPP site;
(4) Move existing line recloser S8686 (install new, salvage existing);
(5) Add new line recloser; and
(6) Primary metering structure (not including cabinet, meter wiring, meter tank).

Project Schedule and Cost

8. The in-service date is scheduled for July 2023.

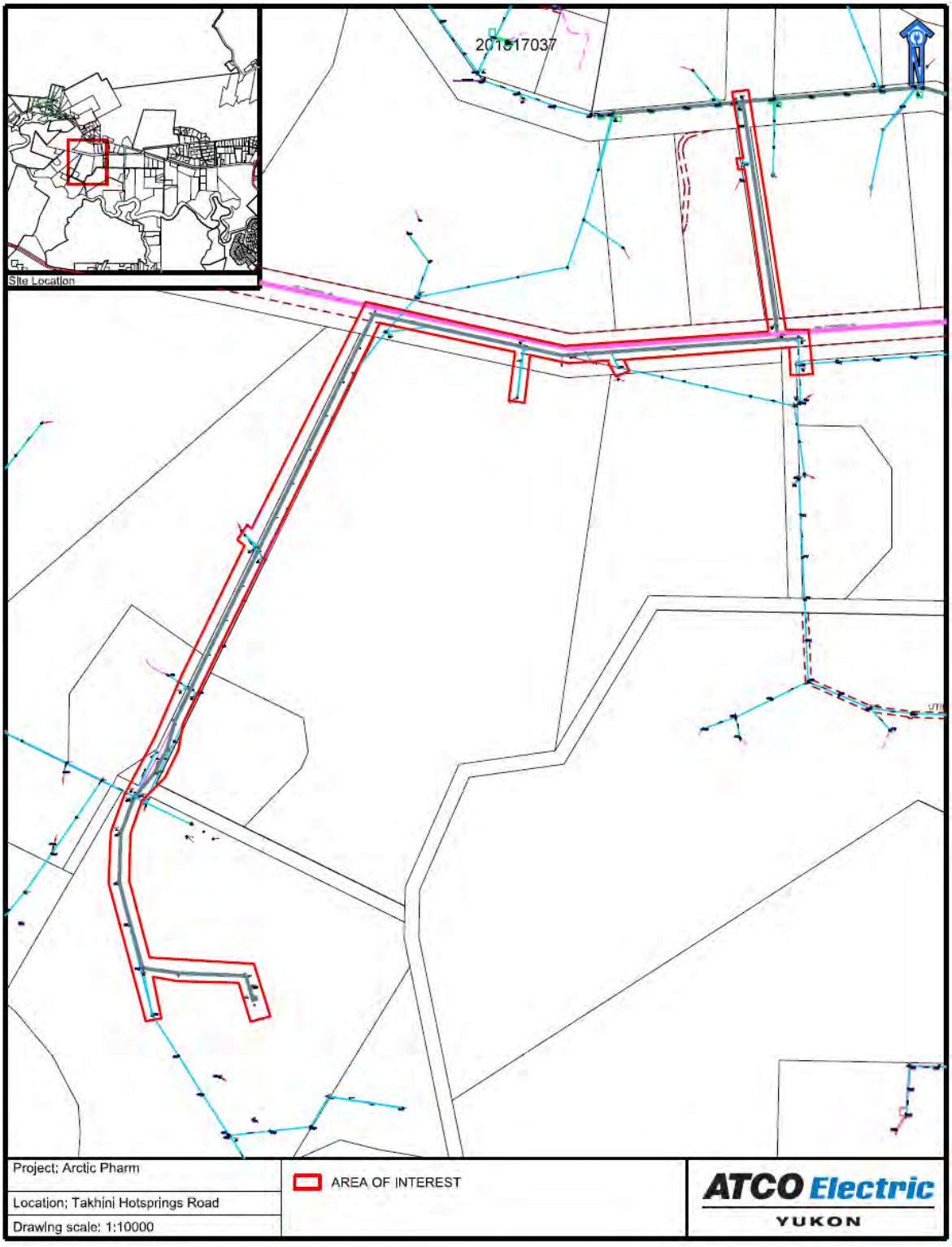
Table 1: Project Schedule and Cost
($000)

Date	Description	Cost
2023	Material	$311
2023	Labour (construction, PM, engineering, commissioning)	$232
TOTAL		**$543**

Appendices

Appendix A ArcticPharm Connection

Appendix A: ArcticPharm Connection



ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Haeckel Hill Customer Connection

2023-2024 Business Case #36

Executive Summary

1. Eagle Hill LP (EHLP) plans to upgrade YEC's Haeckel Hill Wind Park. The Distributed Energy Resource (DER) is connected to AEY's 12.5 kV feeder 4L316 served by Services Substation #5 & McIntyre S170. The Wind Park generation capacity will be increased from 0.8 MW to 4 MW by adding 4 1-MW turbines; the existing turbines will be removed. Expansion of the Haeckel Hill DER site will require upgrades to the AEY Distribution System.

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.

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

Background

4. The Yukon Energy Haeckel Hill Wind Turbine Park was built in 1993 and 2000. It consisted of two turbines that generated approximately 0.8 MW of electricity. The two turbines have reached their end of life and will be removed. EHLP plans to revive and expand the DER by installing four new turbines of 1 MW each. EHLP plans to complete construction in two stages starting in the spring of 2022. The planned ISD is July 2023.

5. This project is part of the Standard Offer Program (SOP) for Yukon's Independent Power Production (IPP) policy.

6. AEY needs to complete upgrades to the 25 kV distribution system to allow the expansion of the Haeckel Hill Wind Turbine Park. Construction is scheduled to begin in June 2022 and finish in July 2023.

7. The overall project map can be seen in Appendix A.

Project Description

8. The most recent Feasibility Study determined the AEY distribution system upgrade scope to accommodate the export increase of the DER:

(1) POI connection AEY owned 12.5 kV gang-operated switch.

(2) Install power quality meter.

(3) Install ~400 m of 375 A capacity cable to connect the wind farm site to an overhead powerline.

(4) Install one three-phase recloser at top of Haeckel Hill (replace S9550).

(5) Install one 300 A voltage regulator.

(6) Install one three-phase recloser (replace S9549).

(7) Install one three-phase recloser near Hamilton Blvd (replace S9226).

(8) 3.7 km conductor upgrade from #4 ACSR to 1/0 ACSR and install one three-phase voltage regulator near Fish Lake unit #1.

(9) Add one 200A voltage regulator near S9549.

(10) Install 3x25 kVA grounding transformer.

(11) Other required system changes (reprogram regulator controllers, change fuses).

Project Schedule and Cost

9. The in-service date is scheduled for July 2023. Table 1 below provides an estimated milestone schedule for the project:

Table 1: Project Timetable

Milestone	Completion Dates
Procuring materials	Q1 2022
Construction line work	Q3 2022
Construction of cable to connect the wind farm to an overhead powerline	Q3 2023
ISD	Q3 2023

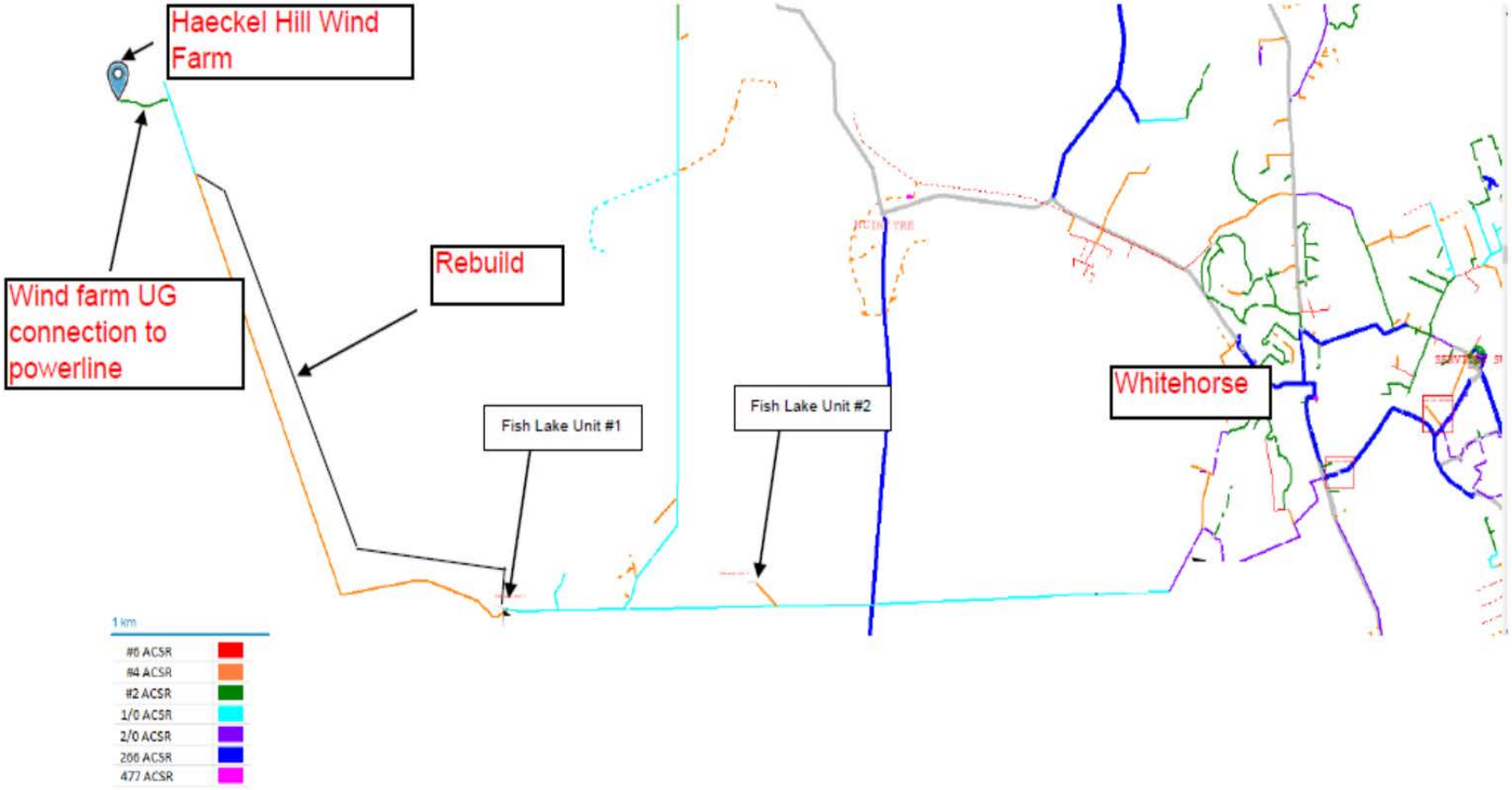
Table 2: Project Cost

Year	Description	Cost
2022	Materials	$451,000
2022/2023	Construction and Commissioning Work	$743,000
2022	Engineering, Project Management, Survey, Techs	$72,000
2022	Brushing and access	$48,000
	Contingency	$140,000
	Total	**$1,454,000**

Appendices

Appendix A Haeckel Hill IPP Map

Appendix A: Haeckel Hill IPP Map



ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Kluane Wind Turbine Integration

2023-2024 Business Case #37

Executive Summary

1. This project is to support the integration of the Kluane Wind Turbine (WT) project being completed by the Kluane First Nation (KFN). This project will introduce wind generation and storage into the existing remote diesel generation and distribution system. The KFN will be installing and owing the WT generation which has a significant penetration level. This requires AEY to install a Battery Energy Storage System (BESS) and Micro Grid Controls (MGC) which will help maximize the WT generation and reduce diesel fuel consumption while ensuring the safety and reliability of the electrical system.

2. This project will consist of a single 900 kw Wind Turbine and 713 kWh of battery energy storage, associated generation integration to the existing plant and Distribution system upgrades.

3. This is a fully contributed customer-driven interconnection project.

Background

4. AEY and KFN have finalized an Electricity Purchase Agreement (EPA) that will help the KFN reduce their reliance on diesel power, achieve greater energy autonomy, and generate economic benefits for the next 25-years. Under the Agreement, KFN will build, own, and operate the Kluane Wind facility.

Project Description

5. The project will include the following:

(1) Installation of BESS and MGC;
(2) Distribution expansion for IPP Interconnection; and
(3) Addition of heat plant, plus plant improvements to facilitate diesel off operation.

Project Schedule and Cost

6. The in-service date is scheduled for June 2024. Table 1 below provides an estimated milestone schedule for the project:

Table 1: Project Timetable

Milestone	Completion Dates
Long lead material procurement	Q3 2022
Design completion	Q2 2023
Distribution construction	Q2 2024
BESS and MGC installation	Q2 2024
System commissioning	Q2 2024

Table 2: Project Costs
($000)

Year	Description	Cost
2022-2024	BESS and MGC supply and install	$2,603
2022-2024	Distribution interconnection	$1,171
2023-2024	Heat plant, plus plant improvements	$430
	Total	**$4,204**

ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Beaver Creek Photovoltaic (PV) Project

2023-2024 Business Case #38

Executive Summary

1. This project is to support the integration of the Beaver Creek Photovoltaic (PV) Project being completed by the Copper Niisüü Limited Partnership (CNLP). This project will introduce Solar PV generation and storage into the existing remote diesel generation and distribution system. The Copper Niisüü Limited Partnership will be installing and owing the PV generation which has a significant penetration level, this requires AEY to install Battery Energy Storage System (BESS) and Micro Grid Controls (MGC) which will help maximize the PV generation and reduce diesel fuel consumption while ensuring the safety and reliability of the electrical system.

2. This project will consist of 1.9 megawatts (MW) DC of solar panels (more than 4000 panels), and 1.2 MW AC of inverters, and 3.5 MWh of BESS and associated generation integration to the existing plant.

3. This is a fully contributed customer-driven interconnection project.

Background

4. AEY and CNLP have finalized a landmark EPA will help the White River First Nation (WRFN) reduce their reliance on diesel power, achieve greater energy autonomy, and generate economic benefits for the next 30 years. Under the agreement, CNLP will build, own and operate the Beaver Creek solar facility, designed to be the largest penetration solar project in the Yukon Territory – a measure of how much power generated by current means is being replaced by solar electricity. In this project's case, solar power will replace more than 55 percent of the diesel generation in the community. The 1.9-megawatt (MW) facility will reduce the amount of diesel needed for electricity generation in the community by 50 percent, a reduction of approximately 325,000 litres/year, and will reduce CO2 emissions by 1,100 tonnes annually.

Project Description

5. The project will include the following:

(1) Installation of BESS and MGC;
(2) Distribution expansion for IPP interconnection; and

(3) Addition of heat plant, plus plant improvements to facilitate diesel off operation.

Project Schedule and Cost

6. The in-service date is scheduled for July 2024. Table 1 below provides an estimated milestone schedule for the project.

Table 1: Project Timetable

Milestone	Completion Dates
Long lead material procurement	Q3 2022
Design completion	Q2 2023
Distribution construction	Q2 2024
BESS and MGC installation	Q2 2024
System commissioning	Q3 2024

Table 2: Project Cost
($000)

Year	Description	Cost
2022	Front end engineering and design	71
2022-2024	BESS and MGC supply and install	5,197
2022-2024	Distribution interconnection	994
2022-2024	Heat plant, plus plant improvements	1,755
Total		**8,017**