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April 22, 2021

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PO Box 577
Charlottetown PE C1A 7L1

Dear Commissioners:

2021 Capital Budget Application – Docket UE20731
Response to Interrogatories from Commission Staff

Please find attached the Company's response to Interrogatories from Commission Staff with respect to the 2021 Capital Budget Application filed on August 6, 2020 and updated on February 1, 2021.

Yours truly,

MARITIME ELECTRIC

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INTERROGATORIES

Responses to Interrogatories
of
Commission Staff

2021 Capital Budget Application
UE20731

Submitted April 22, 2021

The Island Regulatory and Appeals Commission (the "Commission"), in assessing the 2021 Capital Budget Application submitted by Maritime Electric Company, Limited ("Maritime Electric" or "MECL"), requests responses to the following interrogatories:

IR-1 Please explain MECL's process to determine an appropriate contingency for individual capital projects.

a. For capital projects with a contingency greater than ten per cent (10%), please provide an explanation for why the project requires a contingency of this magnitude.

b. Please explain why contingencies appear to only be included in Section 4 – Generation, and not in other sections of the Capital Budget.

Response:

a. Contingency amounts are included in cost estimates to allow for unforeseen costs associated with project uncertainties. Cost uncertainties are common in unique or complex projects as well as when the timeframe between estimating and incurring costs is protracted.

Contingency amounts (typically between 5 per cent and 30 per cent) are determined based on the estimator's judgement/experience, the level of project definition (i.e., percentage of detailed engineering completed) at the time the cost estimate was prepared, the number of potential bidders for a project (i.e., sole source projects often require higher contingencies), and the complexity of the project. When setting contingency amounts, Maritime Electric compares historical project costs to budgeted project costs and adjusts contingency amounts accordingly.

A listing of capital projects with a contingency greater than 10 per cent and the rationale for the contingency is provided as IR-1 – Attachment 1.

b. Maritime Electric does not limit the use of contingencies to generation projects. There are three transmission projects in the 2021 Capital Budget with contingency amounts proposed (i.e., East Royalty Substation, Rattenbury Transformer Upgrade and Mobile Communications System Upgrade) and at times, distribution (e.g., Section 5.8 – Transportation Equipment includes an allowance for unforeseen capital expenditures) and corporate projects are also proposed with contingencies.

Maritime Electric cost estimates often include contingencies similar to those published in the American Association of Cost Estimating (AACE) International's Recommended Practice 18R-97, as shown in Table 1. With this cost estimating methodology, contingencies vary based on the class of cost estimate prepared.

Generation projects tend to include contingency amounts because they are often unique compared to distribution, transmission and corporate projects. For example, of the fifteen capital projects budgeted by Generation for 2021, only four of them were similar to projects that had been carried out in previous years (those being: ECC and Backup Control Centre Miscellaneous Upgrades, CT3 Electrical Generator Overhaul, CT3 Improvements, Parts and Tools, and Borden Combustion Turbine, Building and Services Improvements). The remainder of the 2021 generation projects were of a type that had not been undertaken in the past and therefore were considered unique, with some warranting a contingency amount above 10 per cent based on the estimator's judgement and experience. Most generation projects are estimated to an AACE Class 2 or Class 3 level.

Contingency allocations are often not budgeted for distribution, transmission and corporate projects as they tend to be similar from year to year and the estimator has actual expenditures from the previous years to base the estimate upon. However, there are sometimes exceptions required when the projects are complex (e.g., energized rebuild work or the development of a customized software application) and when civil works are involved (e.g., the construction of a substation on a green field site). In such cases, these projects are also typically estimated to an AACE Class 2 or Class 3 level.

Table 1: AACE International's Recommended Practice for Cost Estimating

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.
[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

IR-2 Please confirm MECL is not seeking a further rate increase in conjunction with its proposed 2021 Capital Budget.

Response:

The Company is not seeking a further rate increase in conjunction with this 2021 Capital Budget Application. The evidence in Section 3.3, which is supported by the calculations in Appendix C, provides an estimate of a full year impact of the proposed 2021 Capital Budget on rate base, revenue requirement and customer rates. As indicated in Section 3.3, the total capital of $41.4 million submitted in the Application is not materially different than the forecast capital expenditures for 2021 provided for in the Final Submission to Commission Staff Docket UE20944 – General Rate Application filed on December 18, 2020 and approved by the Commission in Order UE20-06.

IR-3 Please provide a copy of the Distribution Asset Management Program referenced in Section 3.4(a) Planning Capital Investments – Capital Planning Process.

Response:

The Distribution Asset Management Program document is provided as IR-3 – Attachment 1.

IR-4 In Section 3.4(b) of the Capital Budget, MECL states that "*The Company maintains and annually updates a list of future capital projects based on current information*". Please provide the list of future capital projects for the next five (5) years (i.e. 2022 to 2026 inclusive).

Response:

A list of the Company's future capital projects is provided as IR-4 – Attachment 1. As indicated in Section 3.4(a) of the Capital Budget concerning the proposed 2021 capital projects, the list of future capital projects is also based on the most recent information available with respect to energy and load growth forecasts, inspection program findings, and other factors that may require the timing of projects to be advanced or deferred.

IR-5 Although MECL included Section 3.4(b) Planning Capital Investments – Deferral in the Planning Process in the Capital Budget, there is no ranking or evaluation of the capital projects proposed in the present Application. MECL has indicated that all the projects proposed in the 2021 Capital Budget application cannot be deferred. Please provide a ranking of the capital projects in the Application and differentiate between projects necessary to provide safe and reliable electric service in 2021, and those which are not necessary to provide safe and reliable electric service in 2021.

Response:

All capital projects proposed for 2021 are considered necessary to provide safe and reliable electric service and none rank in priority over the other. Those capital projects not considered necessary in 2021 have been deferred to a future year as outlined in IR-4 – Attachment 1.

Maritime Electric makes capital investments in the electricity supply system to ensure it is sustained in a condition that provides reliable service to its customers and that it has sufficient capacity to meet customer requirements as individual and overall system loads increase. When planning these investments, the Company must exercise control over how it balances the need to refresh system components, based on average service life expectations, and expand the system as new customers are added. Failure to achieve a proper balance can result in system deficiencies that affect safety, reliability and cost. Maritime Electric's process for planning capital projects is described in Section 3.4 of the 2021 Capital Budget Application.

Maritime Electric has structured asset inspection, maintenance and repair programs that factor into the timing of the replacement projects that sustain the system. The Distribution Asset Management Program (DAMP), referenced in the Application and provided in response to IR-3, details how distribution assets are managed so that the overall condition of the distribution system is sustained. Section 8.3 of the DAMP outlines the Company's general approach to identifying system needs for capital budget decision making, recognizing that dynamics outside of the Company's control can change project timing (in some cases with little or no advance notice). Examples of this include the addition of new commercial and large industrial customers and the electrification of space heating which increased system load over the past several years. While the DAMP is specific to the distribution system, generation and transmission assets are managed in a similar fashion and are also subject to the influence of external dynamics.

The list of future capital projects provided in the response to IR-4 was used in the development of the 2021 Capital Budget, as most of the projects proposed for 2021 have been on the project list for several years now. As such, they have already been deferred. Projects are timed to address known or anticipated issues of age, condition, safety, capacity and reliability. While the Company endeavors to provide the most accurate forecast of future capital projects, unforeseen issues can arise causing the timing of projects to change, new projects to be added, and in some cases, significant change to the scope of projects.

While deferral of projects can and does occur, it must be recognized that the prolonged deferral of a project required to sustain the system can result in assets being unsafe for the public and Company employees, lead to more frequent outage events (especially during storm situations) and increase costs because it is often more time consuming to safely work on (or around) deteriorated assets. Similarly, the prolonged deferral of capital projects that are driven by load growth can lead to outages at times of high demand, low voltage situations that can damage customer assets (resulting in damage claims) and be harmful to critical system components.

In addition to the Company's process for planning and forecasting capital projects as already discussed, there is also a need to invest in work support services to meet health, safety and environmental regulatory requirements, communicate effectively with customers, provide functional and safe work facilities for employees, ensure a safe and reliable transportation fleet and provide cyber secure information and operational technology solutions. The evidence provided in the Capital Budget Application and the response provided herein are intended to explain and justify how the need for capital projects is determined, and why the capital projects planned for 2021 are necessary.

Maritime Electric's obligation to serve and its status as a public utility under the *Electric Power Act*, requires the Company to "furnish at all times such reasonably safe and adequate service and facilities for services as changing conditions require." The projects in the 2021 Capital Budget Application have been proposed because they are required now to ensure that this obligation can be met.

IR-6 A number of the projects listed in the Capital Budget indicate they are necessary to improve reliability. Please provide a summary of the current reliability of the PEI grid and identify areas of the PEI grid which need improvement and explain why.

Response:

Summary of Reliability Performance

The primary metric used by Maritime Electric for monitoring its reliability performance is System Average Interruption Duration Index (SAIDI), which reflects the total outage time to the average customer over a period of one year.

Figure 1 below shows the SAIDI data for outages experienced by Maritime Electric customers over the ten-year period 2011 to 2020. For comparison, the composite annual SAIDI performance of neighbouring Atlantic utilities during this same period is also shown[1].

Figure 1: SAIDI Reliability Performance Comparison 2011 to 2020

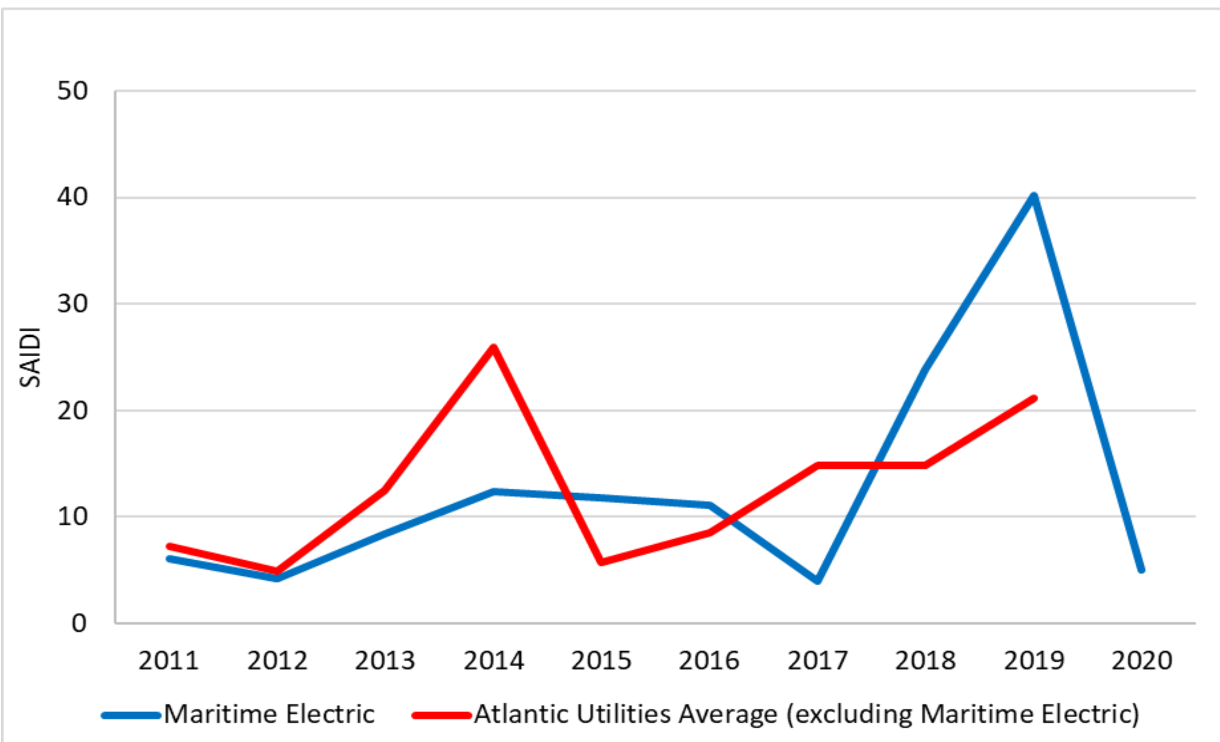


Figure 1 indicates that Maritime Electric customers have experienced a drop in reliability as a result of major storm events over the period[2], as the SAIDI average for the years 2016 to 2020 is approximately double the SAIDI average for the years 2011 to 2015.

While the Company's reliability is comparable within Atlantic Canada, the increasing frequency

[1] Neighbouring Atlantic utilities include New Brunswick Power, Nova Scotia Power and Newfoundland Power. Reliability data for 2020 is not yet available for these utilities.

[2] November 29, 2018 – snow, ice and wind storm, and September 7, 2019 – post tropical storm Dorian.

and duration of outages due to severe weather demonstrates that the system in its current condition is susceptible to damage when storm events occur. This susceptibility coupled with the Island's increased reliance on electricity for space heating puts customers in a vulnerable situation, especially in the winter months. System resilience during major storm events is enhanced by continually investing in equipment and infrastructure to ensure that all system components are in good working condition and able to handle various weather conditions that it needs to endure.

Reliability Improvement Focus Areas

Maritime Electric regularly reviews the age and condition of its distribution and transmission assets. When determining how best to address aged infrastructure and deteriorated or overload conditions, options are identified, cost estimates are prepared and an economic analysis is performed to determine the least-cost solution. Depending on the findings, an upgrade, a rebuild or new construction may be undertaken to improve reliability.

The following distribution, substation and transmission line improvements have been included in Maritime Electric's list of future capital projects (provided as IR-4 – Attachment 1) for the purpose of reliability improvement.

- ***Distribution***

  The reliability data for distribution circuits and feeders can vary considerably from year to year but over longer periods it is useful for identifying the areas where system improvements are needed. Table 1 shows the rural feeders with the highest outage hours for the period 2016 to 2020. Reliability information for urban feeders is provided in the Company's response to IR-17.

Table 1
Rural Feeders with Highest Outage Hours 2016 to 2020

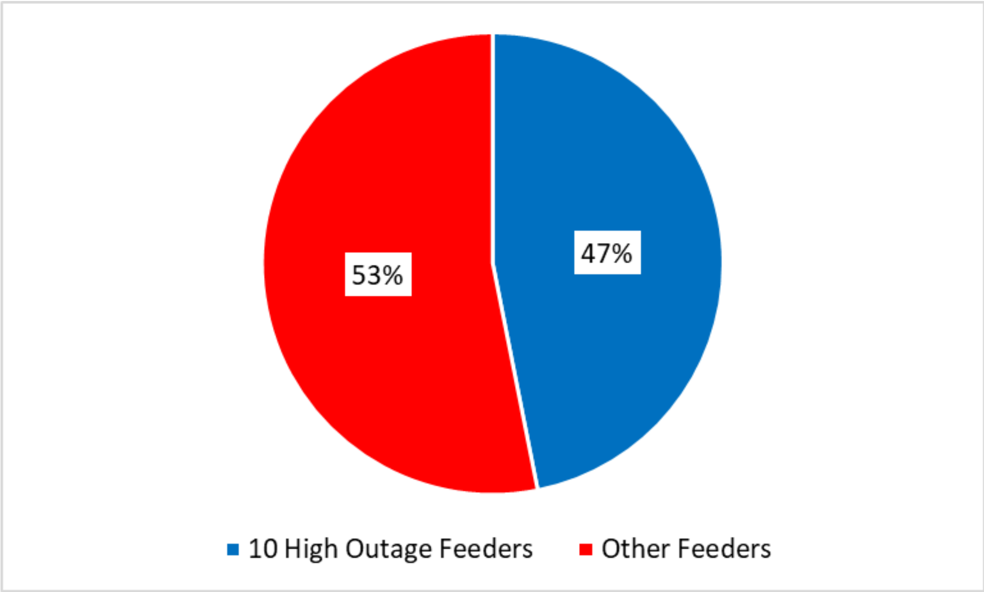
Circuit	Feeder	Customer Outage Hours*	Customer Count	Total Feeder Length (km)
Bonshaw	WR02200	70,607	6,761	325
Tignish West	AL00295	55,567	2,789	251
Crapaud	AB33125	47,446	1,217	101
O'Leary East	OL00971	32,077	2,544	242
Bedeque	AB33127	25,618	1,928	168
Stanley Bridge	RT01085	23,844	904	71
Covehead	AP52200	22,424	969	64
Irishtown	KN80400	20,098	2,260	171
Eldon-Belfast	VC01440	16,955	1,481	209
Alberton	AL00200	16,527	1,355	70
TOTAL		**331,163**	**22,208**	**1,672**

* Excludes customer outage hours resulting from transmission and substation outages.

Based on the data in Table 1, observations concerning the collective impact of these feeders on system reliability, and information on what is planned to improve the reliability of each feeder, is provided below.

Figure 2 shows that in terms of customer outage hours, the ten rural feeders with the highest outage hours account for 47 per cent of all outage hours over the period.

Figure 2: Percentage of Total Outage Hours Due to the Ten Rural Feeders With the Highest Outage Hours, 2016 to 2020



Collectively the ten rural feeders with the highest outage hours serve approximately 28 per cent of the Company's customer base and account for approximately 31 percent of the total length of feeders in the distribution system, as shown in Figures 3 and 4, respectively.

Figure 3: Percentage of Customers Served by the Ten Rural Feeders with the Highest Outage Hours, 2016 to 2020

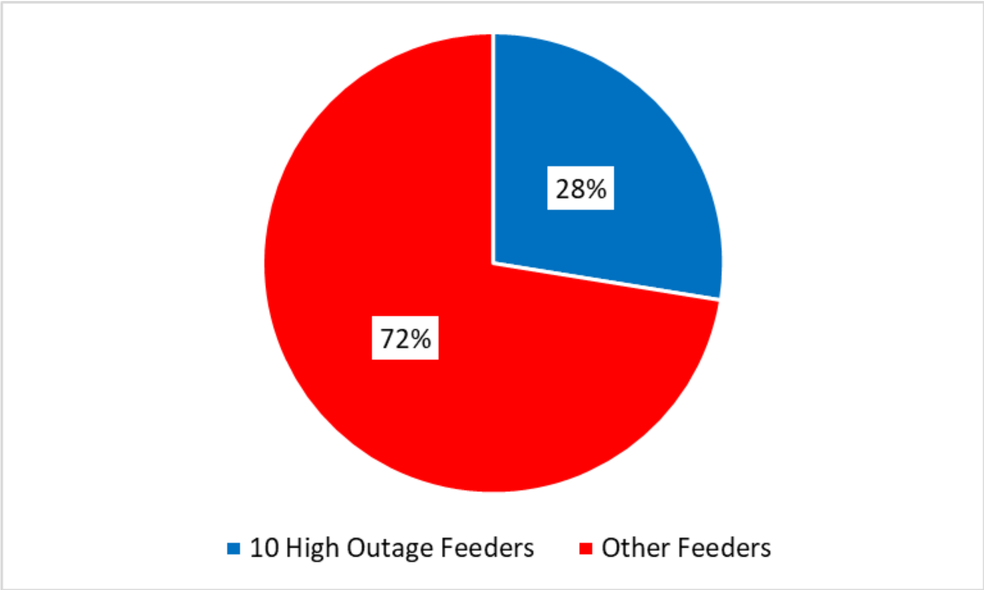
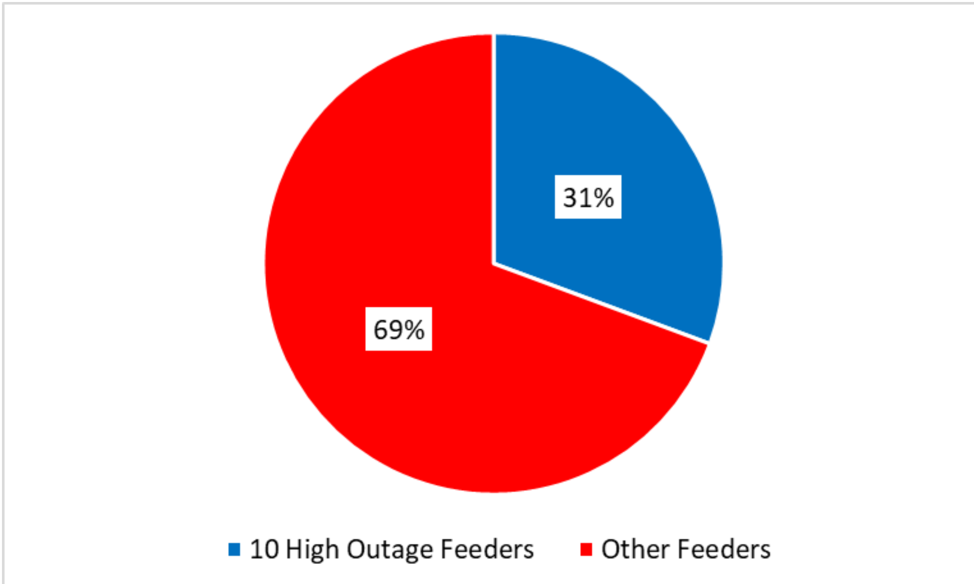


Figure 4: Percentage of Total Feeder Length Represented by the Ten Rural Feeders with the Highest Outage Hours, 2016 to 2020



The Bonshaw circuit from West Royalty Substation has been identified as an area for improvement due to its long length and the high number of customers serviced from the circuit. Once the Clyde River Substation and proposed new Y-119 are in service, reliability for the customers on the Bonshaw circuit will improve.

The Tignish West circuit from the Alberton Substation has been identified as an area for improvement due to its long length and the high number of customers serviced from the circuit. A new Tignish Substation would provide improved reliability and a reduction of system losses. The cooperation of the PEI Energy Corporation will be required to establish the Tignish Substation as it owns transmission line T-23 (between Alberton and Tignish). Once the Tignish Substation is built (currently planned for 2026 pending regulatory approval), reliability for the customers in the Tignish area will improve.

The Crapaud circuit from the Albany Substation has been identified as an area for improvement due to the high number of customers serviced from the circuit. Once the New Albany Feeder project is in service (currently planned for 2025 pending regulatory approval), reliability for the customers on the Crapaud circuit will improve.

The O'Leary East circuit from the O'Leary Substation has been identified as an area for improvement due to its long length and the high number of customers serviced from the circuit. Once the Smallman Road project is in service (currently planned for 2021 pending regulatory approval), reliability for the customers on the O'Leary East circuit will improve.

The Bedeque circuit from the Albany Substation has been identified as an area for improvement due to the high number of customers serviced from the circuit. Once the Blue Shank Road line extension project is in service (currently planned for 2024 pending regulatory approval), reliability for the customers on the Bedeque circuit will improve.

The Stanley Bridge circuit from the Rattenbury Substation had high outage hours for the period due to the high number of customers that it serviced. The situation has been improved through a combination of the Bagnall Road Substation and the recently completed St. Mary's Road line extension project.

The Covehead circuit from the Airport Substation had been identified as an area for improvement due to its long length and high number of customers serviced from the circuit. The situation has recently been improved with the completion of the North Shore Feeder project in 2020.

The Irishtown circuit from the Kensington Substation has been identified as an area for improvement due to its long length and high number of customers serviced. Upgrade requirements for the area will be proposed with a future capital project.

The Eldon-Belfast circuit from the Victoria Cross Substation has been identified as an area for improvement due to its long length and high number of customers serviced from the circuit. Upgrade requirements (possibly a voltage conversion) will be proposed with a future capital project.

The Alberton circuit from the Alberton Substation has been identified as a high outage area for the period. Further investigation is required to determine if there are chronic issues that need to be addressed.

- ***Substations***

  The Crossroads Substation which was built in 1978 has been identified as a rebuild priority. The winter peak load in the substation has grown by 15.5 per cent from 2019. The wood structures, including insulators and switches, are visibly deteriorated and are now approaching end of useful life. The structures within the station are congested and the safety clearances do not meet current standards. The 12.5 kiloVolt (kV) buses are aged and do not provide adequate ampacity to meet the increased load conditions. The mobile bay can accommodate the original mobile transformer but was not constructed to accommodate a larger new mobile transformer.

  The design of the proposed Crossroads Substation Upgrade project is currently scheduled for 2021, pending regulatory approval. Construction would have to be completed over two years due to the winter load constraints. Phase 1 of the project is planned to begin in spring 2022 and be completed in fall 2022. Phase 2 would follow in spring 2023 and be completed by the end of the year.

  Power transformers in substations are identified and replaced as they reach the end of useful life or near maximum capacity. This involves completing a transformer study that assesses alternatives such as replacing it with a larger transformer, adding a second or third transformer, or building a new substation.

- ***Transmission Lines***

  T-11 connects the Summerside Electric Ottawa Street Substation to the Maritime Electric Sherbrooke Substation. It was originally constructed in 1963 and a short section was rebuilt in 1997 with larger conductor. The City of Summerside is the only customer connected to T-11. The original sections of the line are aged and need to be replaced. The line must remain in service while it is being replaced in order to maintain supply to

Summerside. This presents a number of technical and safety challenges and Maritime Electric is currently working on plans to replace the aged sections of the line in 2022, pending regulatory approval.

T-4 connects the Lorne Valley and Scotchfort Substations and has reached its end of useful life. It was constructed in 1969 and over the past decade the line has become increasingly in need of outage response and repair. Construction of the proposed East Royalty Substation in 2022 would result in the Scotchfort Substation no longer being required for the medium term, and T-4 could be permanently de-energized. The existing Scotchfort load would be divided between the new East Royalty Substation and the West St. Peter's Substation. In the long term, it is expected that a new substation in the Scotchfort area will be required with continued load growth in the area.

The Wellington and St. Eleanor's Substations are currently fed from the 69 kV transmission line T-5 and the O'Leary and Alberton Substations are fed from the 69 kV transmission line T-21. These substations are all supplied from radial transmission lines which means they cannot currently be backfed from any other 69 kV line. An outage on T- 5 results in the loss of the Wellington, St. Eleanor's, O'Leary and Alberton Substations which collectively service approximately 12,000 customers. An outage on T-21 results in the loss of O'Leary and Alberton Substations.

The O'Leary Interconnection project is currently planned to be built in 2025/2026 (pending regulatory approval) near the current O'Leary Substation and would serve as an interconnection point between Y-115 (138 kV), and T-21 and T-5 (69 kV) through a 75 megavolt amperes (MVA) autotransformer. Y-115 was constructed in 2009 to connect the 99 megawatt (MW) West Cape Wind Farm to the Sherbrooke Switching Station. The Integrated System Plan identifies the need to connect Y-115 and T-21 in 2027 to improve voltages in western PEI. A 138/69 kV stepdown autotransformer in the O'Leary area will provide an increase in reliability and significant voltage support for western PEI customers. It will also help offload the Sherbrooke autotransformers that are approaching their rated thermal levels.

The annual customer outage hours west of Sherbrooke is approximately 149,900 hours, which is above average. Analysis has shown that the O'Leary Interconnection project would reduce the average annual customer hours of outage in western PEI by 38 per cent to 92,900 hours. Impacts from the PEI Energy Corporation's proposed new western 138 kV line have not been included in this reliability analysis; however, a system impact study for this new line is being done and the results will be incorporated into the O'Leary Interconnection design.

T-10 serves the Victoria Cross and Dover Substations and was constructed in 1992. It is in fair condition but has incurred considerable storm damage over the years. The Company will continue to pay particular attention to its inspections results, and may have to undertake either spot or full replacement depending on the line's overall condition in the future.

IR-7 Please provide a map of the current electric grid and indicate the proposed 2021 capital projects.

Response:

A map of the current electric grid, showing major supply system components and the location of the proposed 2021 capital projects, is provided as IR-7 – Attachment 1.

Whereas some Section 5.0 – Distribution project categories (i.e., projects in Sections 5.1, 5.2, 5.3, 5.4a, 5.5b-d, 5.6, 5.7 and 5.8) and Section 6.0 – Transmission projects (i.e., projects in Sections 6.1e[iii], 6.1g, 6.1i-j, and 6.2b) cannot be assigned to one location as the work occurs throughout the province. As a result, not all projects proposed in the 2021 Capital Budget Application are shown on the map. This also applies to projects in the 7.0 – Corporate category as all projects are identified as work support services.

IR-8 Please provide an estimated 5-year capital budget in dollars for major categories Generation, Distribution, Transmission and Corporate for 2022 to 2026.

Response:

The estimated five-year capital budget in dollars for major categories Generation, Distribution, Transmission and Corporate for 2022 to 2026 is shown in Table 1.

Table 1
Estimated Capital Expenditures for Major Budget Categories 2022 to 2026

Capital Budget Category	2022	2023	2024	2025	2026
4.0 - Generation	$1,010,000	$1,950,000	$1,760,000	$3,090,000	$13,770,000
5.0 - Distribution	37,500,000	37,500,000	40,250,000	30,600,000	30,125,000
6.0 - Transmission	8,630,000	8,810,000	8,940,000	10,500,000	13,925,000
7.0 - Corporate	7,185,000	12,165,000	3,760,000	2,485,000	2,340,000
TOTAL	**$54,325,000**	**$60,425,000**	**$54,710,000**	**$46,675,000**	**$60,160,000**

IR-9 Please provide MECL's policies for personal use of vehicles, purchase of new vehicles, and what criteria must be met to determine whether a vehicle is required for a specific position.

Response:

Personal Use of Vehicles
Maritime Electric does not allow the personal use of Company-owned vehicles with one exception. The following excerpt from clause 1.2 of Maritime Electric Corporate Procedure No. 850229 "Use of Motor Vehicles on Company Business" (provided as IR-9 – Attachment 1) addresses the personal use of Company vehicles as follows:

> *"Employees may use Company vehicles only when conducting Company business. Further, no employee is permitted to transport in a Company vehicle any family member, friend or other non-employee of the Company unless it is a contractor hired by the Company. A vehicle that is part of a compensation package is exempt from these restrictions."*

The Company does allow employees to use their personally-owned vehicles for specific Company business provided they have the approval of their supervisor. This type of arrangement is addressed in clause 5b of Maritime Electric Corporate Procedure No. 800009 "Travel and Business Expenses" (provided as IR-9 – Attachment 2).

> *"Employee's Vehicle: If it is the most economical and practical method, the employee's vehicle may be used in the performance of Company business and a mileage allowance rate will be paid at the rate established from time to time. An employee using his/her vehicle sufficiently to be classified under insurance for "business purposes' shall be reimbursed by the Company for the difference between normal insurance rates and those charged for "business purposes". The employee must obtain the approval of the Supervisor before incurring the expense. For bargaining unit employees, Article 38.80 may apply."*

Purchase of New Vehicles
The criteria used by Maritime Electric to determine when to replace an existing vehicle with a new vehicle was included in the Maritime Electric Transportation Equipment Justification document, provided as Appendix "N" of the Company's 2021 Capital Budget Application. For ease of reference, this information is presented in Table 1 and the italicized text that follows below.

Table 1 Maritime Electric Replacement Criteria for Vehicles	
Tracked Heavy Vehicles	15 years
Heavy/Medium Flat Bed Trucks	10 years or 250,000 km
Heavy Vehicles	10 years or 250,000 km
Service Trucks (CSUP – run double shift) Medium Vehicles	5 years or 250,000 km
Passenger Vehicles	7 years or 200,000 km

The age and mileage of the vehicle are the primary replacement factors but vehicles are also evaluated on a number of additional criteria such as annual maintenance costs, PTO [power take-off] hours (if applicable) and vehicle condition (rust, electrical issues, etc.) to determine whether they have reached the end of their useful service lives. Based on such evaluations, it has been forecast that each unit proposed for replacement will reach the end of its useful service life and require replacement in 2021.

The expenditures for individual vehicle replacements are not inter-dependent. However, they are similar in nature and justification. The expenditures are, therefore, pooled for consideration as a single capital project. The following table contains further information pertaining to the heavy and medium fleet vehicles to be replaced in 2021 as these three vehicles alone make up approximately 70 per cent of the overall transportation budget.

Maritime Electric does not have a written policy or guideline to be followed when deciding if or when the size of the vehicle fleet needs to change. The Vice President of the applicable department or the Manager in charge of the vehicle fleet ultimately decides on any vehicle fleet changes.

Factors that determine if and when vehicles are added to the vehicle fleet include: changes within the organization including growth in number of employees who work primarily in the field; workloads; changes in job duties and responsibilities; and special project requirements.

Criteria to Determine if a Vehicle is Required for a Specific Position

It is the responsibility of each department's Vice President and Manager to determine which positions require a Company vehicle to perform their job safely and efficiently.

This involves an evaluation of whether that position requires the employee to regularly travel to various work locations. An example of a position which requires the employee to perform the majority of their work in the field is the Engineering and T&D Utility Person (or "Surveyor") position. Company surveyors constantly travel to and from job sites involving new service connections, distribution line rebuilds, transmission line routings, etc. If the employee performs the majority of their work in the field then a direct assignment Company vehicle is usually warranted.

If an employee's field activity is limited, they typically use their own personal vehicle and claim a per kilometer travel allowance, or they arrange to use a pooled Company vehicle.

IR-10 Please provide MECL's timeline of future plans related to the ECC building.

Response:

Maritime Electric's Energy Control Centre (ECC) function is critical to the operation of the electric grid and the supply of electricity to customers. The ECC building, located on Cumberland Street in Charlottetown, was constructed in 1976.

In recent years, several upgrades were completed to the ECC building including control room renovations in 2017, and washroom and kitchen renovations in 2020.

Future capital projects planned for the ECC building within the next five years include:

- Upgrades to the building's heating, ventilation and air conditioning (HVAC) systems;
- Upgrades to the building's electrical system; and
- Roof replacement.

The exact timelines for these projects will depend on the results of ongoing asset condition monitoring and the availability of resources to complete the work. These upgrades are expected to be required within the next five years due to the building's age (45 years old).

IR-11 *Section 4.1 (a) - Energy Control Centre Upgrades* – please explain why a number of the items included in the description appear to be repairs and maintenance rather than capital additions. Please provide justification for capitalizing these items.

Response:

Repairs or maintenance work completed to the Energy Control Centre (ECC) building is charged to Maritime Electric's operating expense accounts.

The projects listed under the ECC Upgrades project include the addition of new equipment (i.e., standing desks and automatic external defibrillator [AED]), the replacement of physical assets (i.e., replacement of front door and duct heaters, and miscellaneous upgrades) that have attained or exceeded their useful life, and an engineering study to identify heating system changes required as a result of heating, ventilation and air conditioning equipment reaching end of life. Component replacements are necessary when repairs to the existing ones are not economical. The installation of new assets that will last for several years and the studies required to identify those assets are considered capital additions.

The capitalization of these project costs are similar in nature to those previously reviewed and approved by the Commission and are based upon established good utility practice as supported by accounting standards and guidelines that currently exist throughout the industry.

Maritime Electric follows Canadian Private Entity Generally Accepted Accounting Principles (GAAP), which allows reference to other guidance including accounting principles established in the United States. In the United States, the Federal Energy Regulatory Commission (FERC), which regulates the transmission and wholesale sale of electricity, developed a Uniform System of Accounts (USofA) for the financial accounting of regulated utilities. Following the FERC USofA is considered good utility practice in Canada. According to FERC, to capitalize project costs, the costs must meet the following two qualifications:

1. Extend the life, increase the capacity or improve the safety or efficiency of an existing asset owned by a company; and

2. Improve the condition of that asset after the costs are incurred as compared with the condition of that asset when originally constructed or acquired.

The items listed in Section 4.1(a) are either new assets or meet the FERC requirements that justify them as capital costs.

IR-12 *Section 4.2 (d) – Combustion Turbine Improvements, Parts & Tools* – please explain why a number of the items included in the description appear to be expense in nature rather than capital additions. Please provide justification for capitalizing these items.

a. In addition, please provide an explanation for why this provisional amount was increased substantially over the historical 5-year average.

Response:

As noted in the Application, the increase in the budget provision over the historical five-year average is due to planned purchases of electrical/instrumentation tools, mechanical tools, and vibration monitoring equipment (all of which will last for several years) for Combustion Turbine 3 (CT3) that are above the traditional provisional amounts for in-service component failures.

The capitalization of costs for Combustion Turbine Improvements, Parts and Tools are similar in nature to those previously reviewed and approved by the Commission (i.e., item 4.2b Combustion Turbine Improvements in Maritime Electric's 2020 Capital Budget) and are based upon established good utility practice as supported by accounting standards and guidelines that currently exist throughout the industry.

Maritime Electric follows Canadian Private Entity Generally Accepted Accounting Principles (GAAP), which allows reference to other guidance including accounting principles established in the United States. In the United States, the Federal Energy Regulatory Commission (FERC), which regulates the transmission and wholesale sale of electricity, developed a Uniform System of Accounts (USofA) for the financial accounting of regulated utilities. Following the FERC USofA is considered good utility practice in Canada. According to FERC, to capitalize project costs, the costs must meet the following two qualifications:

1. Extend the life, increase the capacity or improve the safety or efficiency of an existing asset owned by a company; and

2. Improve the condition of that asset after the costs are incurred as compared with the condition of that asset when originally constructed or acquired.

Section 4.2(d) is provisional in nature and actual expenditures will only be incurred on this project if required to sustain the safe and reliable operation of CT3. To this end, project expenditures, if incurred, will meet the requirement of improving safety and/or efficiency of an existing asset (i.e., CT3) and therefore, qualify as a capital addition. As well, the expenditures classified as capital under this budget item will include only those that will improve the overall condition of the asset in question (i.e., a betterment) in order to meet the second qualification under FERC. Smaller, minor repairs are not included in the Capital Budget but instead will be charged to operating expense as incurred.

a. This budget category is a recurring project that is provisional in nature and is needed to ensure there is sufficient budget available for unplanned and emergency events that cannot be identified in advance. Unplanned and emergency events generally do not occur in a consistent or predictable manner, which is reflected in the variability of the historical amounts. Actual costs are only incurred if needed for the safe and reliable operation of CT3 but it is necessary to have sufficient provisional budget available for these events should they occur.

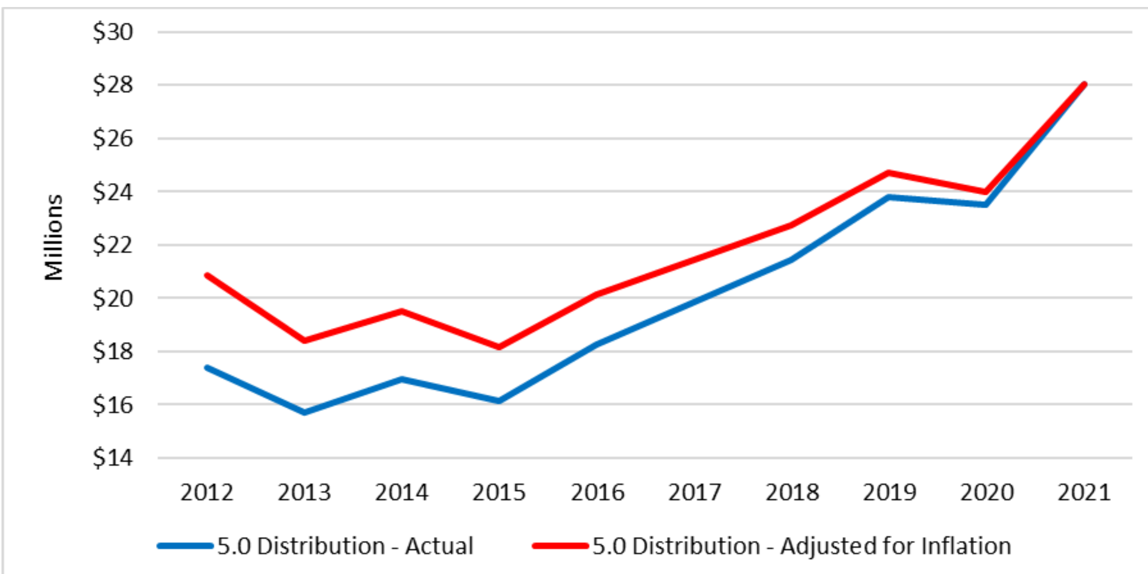
IR-13 *Section 5 – Distribution* has increased significantly (approximately 60 per cent) in the last ten years. Please explain the reason for this increase.

Response:

There are several reasons that capital investment in the distribution system has increased since 2012 including inflation of material and labour costs, customer and load growth, and new programs to replace aged and deteriorated assets, improve reliability and meet health, safety and environmental regulatory requirements.

Inflationary increases should be considered when comparing capital expenditures over the years to provide a more accurate reflection of any changes in system investment. When the actual expenditures are normalized for an estimated annual inflation rate of 2.0 per cent, the total Section 5 – Distribution expenditures for 2012 increases to $20,846,219 (from $17,371,849). This change reduces the increase over the last ten years to approximately 35 per cent. The actual and inflation adjusted capital spending on Distribution for 2012 to 2021 (as proposed) is shown in Figure 1 and the corresponding values, broken down by subcategory, are tabulated in IR-13 – Attachment 1.

Figure 1: Actual and Inflation Adjusted Capital Spending on Distribution 2012 to 2021



Capital spending in Distribution is also affected by customer and load growth. Over the last ten years (2011 to 2020), Maritime Electric's customer base and peak load growth has increased by 12 per cent and 29 per cent, respectively, as shown in Figures 2 and 3. These increases directly result in the need to expand and upgrade the distribution system to ensure that the Company can effectively meet its service obligation and duties as a public utility.

Figure 2: Maritime Electric Annual Customer Count 2011 to 2020

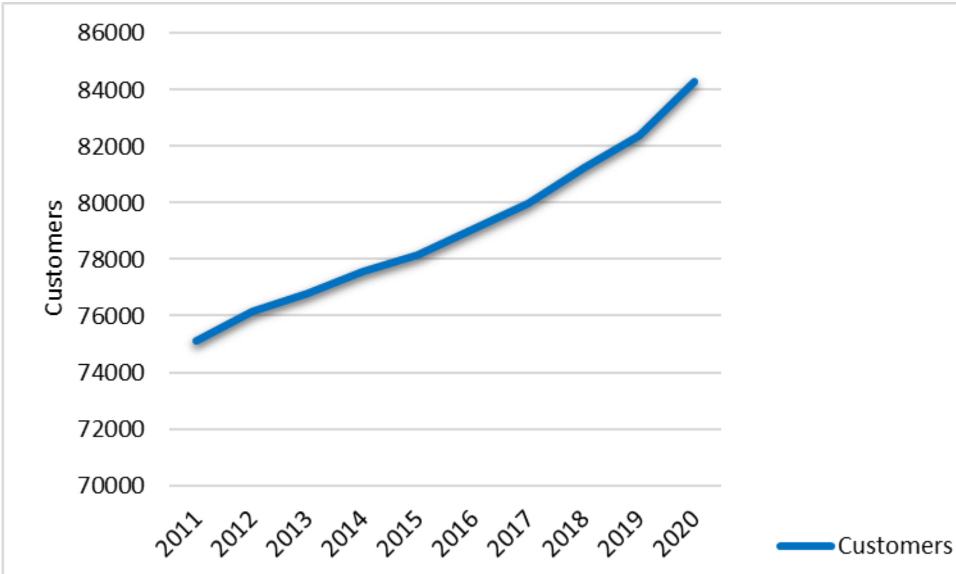
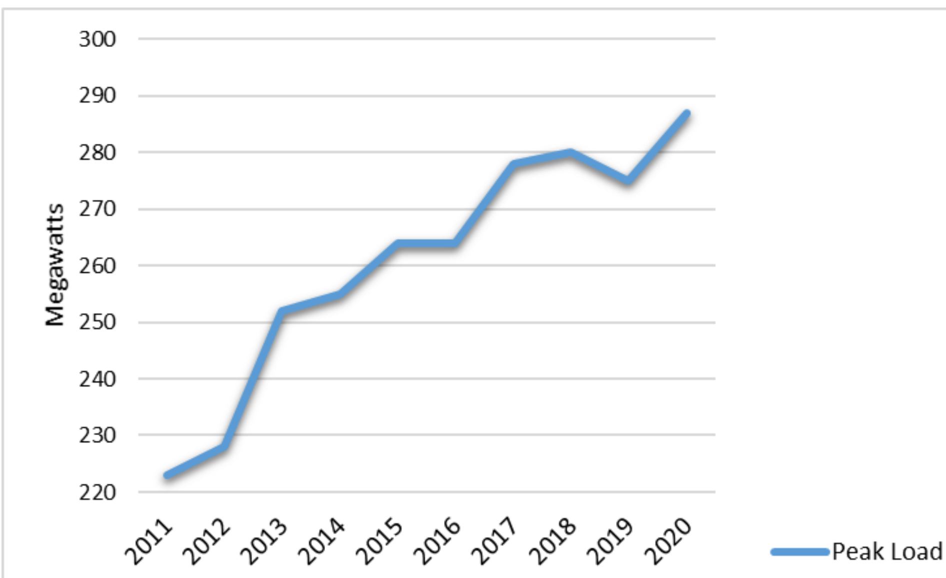


Figure 3: PEI Annual Peak Load 2011 to 2020



The Distribution breakdown in IR-13 – Attachment 1 provides insight into which subcategories have contributed to the overall expenditure increase within the category. The largest contributor, both in terms of amount and percentage increase, is in Section 5.5 – Line Rebuilds. The increase in Line Rebuilds is directly related to the capital budget proposed for PEI Broadband Project in 2021, which at $4,431,000 represents 47 per cent of the proposed total budget for Distribution. The PEI Broadband Project is a customer-driven initiative that falls within the Company's obligation to serve and to accommodate the joint use of its poles for attaching communication equipment, as required by Section 8(1) of the Electric Power Act. It is worth noting that excluding the proposed PEI Broadband Project budget for 2021 changes the normalized ten-year (2012 to 2021) increase in Distribution and Line Rebuilds to approximately 13 per cent and 5 per cent, respectively.

The Distribution budget has also increased significantly (72 per cent normalized) over the last ten years in Section 5.8 – Transportation Equipment. The increase is related to both the number and the cost of new vehicles (e.g., line trucks, pick-up trucks, vans) and other transportation equipment (e.g., pole trailers) required to provide service to customers and transport employees, equipment and materials to work sites across the province. A comparison of the 2012 to 2021 transportation equipment requirements, shows that cost increases for comparable vehicles range from 60 per cent to over 100 per cent with 7 vehicles budgeted in 2012 and 12 budgeted in 2021.

Other Distribution budget subcategories that have increased over the past ten years (when expenditures are normalized) include Sections 5.2 – Distribution Transformers (approximately 40 per cent increase), 5.3 – Services and Street Lighting (approximately 14 per cent increase), and 5.6 – Distribution Equipment (approximately 12 per cent increase). These increases are reasonable and consistent with what should be expected based on the customer and peak load growth that has occurred over the past ten years.

Another component of Distribution that has seen increases in recent years is Section 5.1 – Replacements Due to Storms, Collisions, Fire and Road Alterations. This increase is directly related to increased capital spending on road work and bridge repair by the PEI Department of Transportation and Infrastructure. Road and bridge work often requires alterations to the distribution system that typically involve a combination of temporary changes to accommodate construction, and permanent changes to align with new highway and bridge infrastructure.

Programs to replace aged and deteriorated assets (e.g., porcelain cutouts and eastern cedar poles) and modernize the distribution system with new and more energy efficient components (e.g., LED streetlight conversion) have been added in the past ten years. This has also factored into the increase in Distribution spending. These programs have been successful in achieving reliability improvements, eliminating safety hazards and reducing energy consumption. For example, since the Porcelain Cutout Replacement Program was initiated, the annual number of outages caused by cutout failure has reduced from 308 in 2011 to 30 in 2019.

The various dynamics discussed above have contributed to the increased expenditures in Distribution over the last ten years and are expected to have an ongoing influence on distribution system investment requirements in the future. When planning these investments, Maritime Electric seeks to balance the need to sustain and expand the system, as assets deteriorate and load growth continues.

IR-14 *Section 5.1 (a) – Replacements due to storms, fire and collisions* - MECL identified 3 of the previous 5 years have experienced increased storm activity. However, the budget amount for the 2021 year is lower than the 5-year average. Please explain MECL's rationale for decreasing the provisional budget, considering 3 of the last 5 years included increased storm related repairs.

Response:

The five-year average for storms, fire, and collisions excluding capital expenditures associated with response to significant storm events is approximately $950,000. Significant storm event response costs are not included in the Capital Budget as their occurrence and the nature of the damage to the system is extremely unpredictable. The Capital Budget request for 2021 is $970,000 which represents a reasonable increase for inflation compared to the five-year average.

IR-15 *Section 5.2 – Distribution Transformers* - Table 25 – 2019 column does not add correctly. Please update.

Response:

The amount shown for “Contractor Labour” in 2019 was incorrect in Table 26 of the 2021 Capital Budget Application. The correct amount is shown below in the revised Table 26.

Table 26
Historical and Proposed Expenditures
Distribution Expenditures History

	2016	**2017**	**2018**	**2019**	**2020**	**2021 Proposed**
Material	$1,932,083	$2,706,219	$2,714,234	$3,328,997	$3,132,378	$4,211,000
Contractor Labour	354,385	112,448	154,102	10,963	36,652	56,000
Internal Labour and Transportation	574,120	515,080	395,282	582,219	600,717	872,000
Other	6,023	21,008	3,829	2,006	39,845	53,000
TOTAL	**$2,866,611**	**$3,354,755**	**$3,267,447**	**$3,924,185**	**$3,809,592**	**$5,192,000**

IR-16 *Section 6 – Transmission* has increased significantly (approximately 250%) in the last ten years. Please explain the reason for this increase.

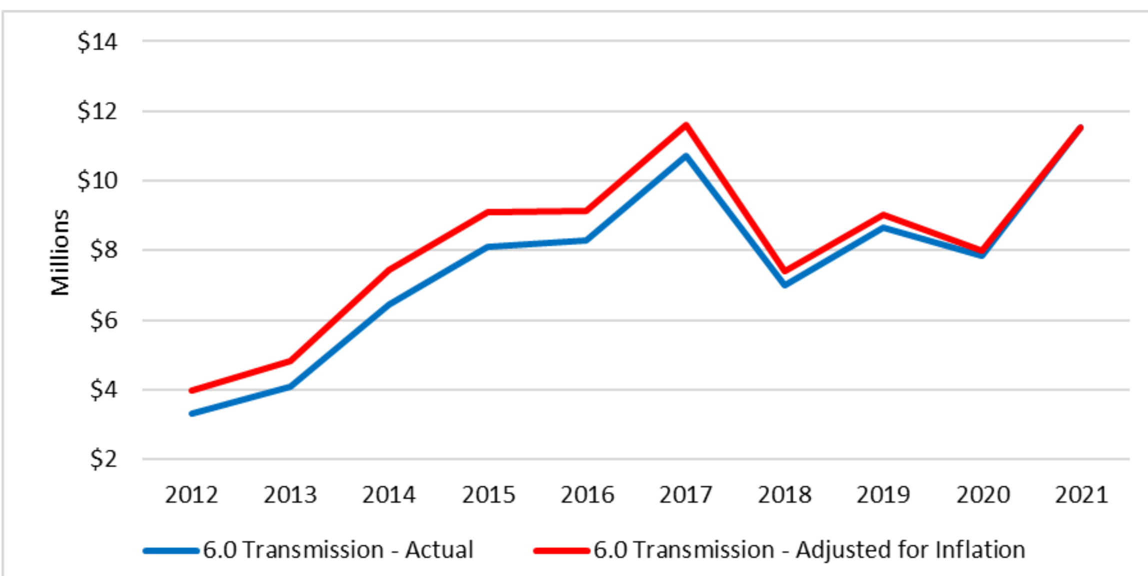
Response:

The Company's Integrated System Plan provides an advanced indication of major transmission and substation projects. Capital investments in substations are required for improving or maintaining reliability by proactively upgrading deteriorating facilities and adding system capacity to avoid overloads.

There are several reasons that capital investment in the transmission system has increased since 2012. Reasons for the increases include inflation of material and labour costs, customer and load growth, and new programs to replace aged and deteriorated assets, reliability improvement and to meet health, safety and environmental regulatory requirements.

Inflationary increases should be considered when comparing capital expenditures over the years to provide a more accurate reflection of any changes in system investment. When the actual expenditures are normalized for an estimated annual inflation rate of 2.0 per cent, the total Section 6 – Transmission expenditures for 2012 increases to $3,966,562 (from $3,305,468). This change reduces the increase over the last ten years to approximately 190 per cent. The actual and inflation adjusted capital spending in Transmission for 2012 to 2021(as proposed) is shown in Figure 1 and the corresponding values, broken down by subcategory, are tabulated in IR-16 – Attachment 1.

Figure 1: Actual and Inflation Adjusted Capital Spending on Transmission 2012 to 2021



Capital spending in Transmission is also affected by customer and load growth. Over the last ten years (2011 to 2020) Maritime Electric's customer base and peak load growth has increased by 12 per cent and 29 per cent, respectively, as shown in Figures 2 and 3. These increases drive the need to gradually expand and upgrade the transmission system to ensure that the Company can effectively meet its service obligation and duties as a public utility.

Figure 2: Maritime Electric Annual Customer Count 2011 to 2020

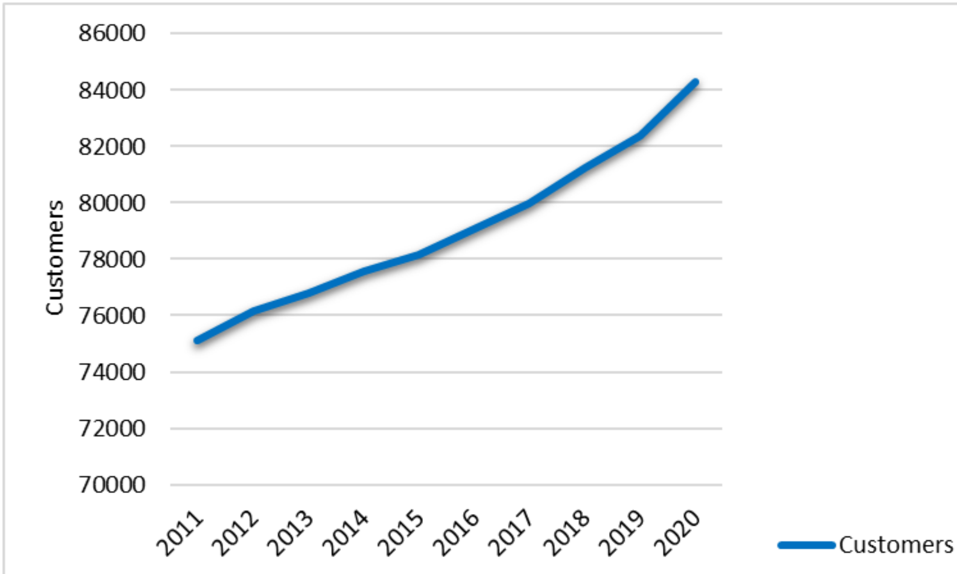
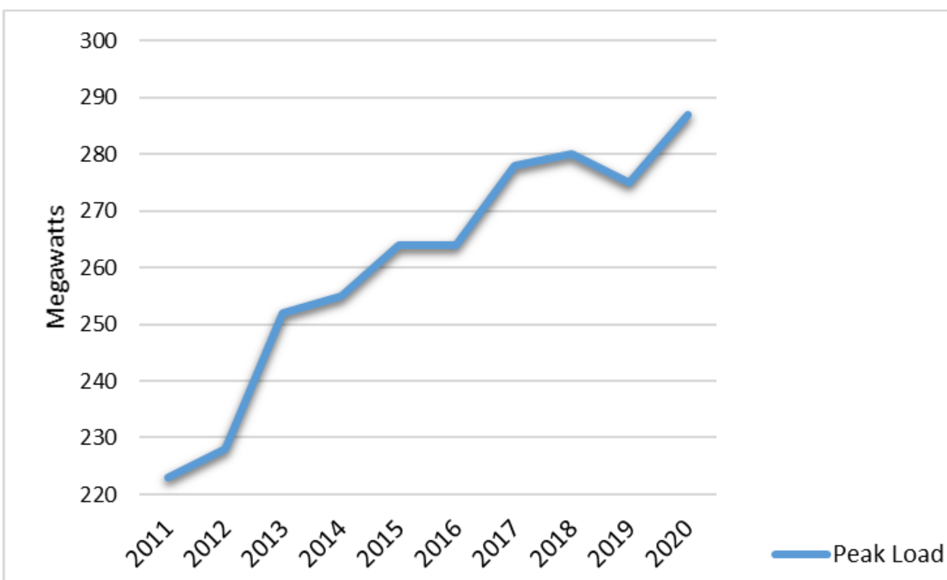


Figure 3: PEI Annual Peak Load 2011 to 2020



The breakdown of transmission spending provided in IR-16 – Attachment 1 provides insight into how the two major cost components, Section 7.1 – Substation Projects and Section 7.2 – Transmission Projects, have contributed to the overall expenditure increase within the category. The data in IR-16 – Attachment 1 shows an increase in substation spending over the past five years while spending on transmission lines has varied throughout the period. Additional insight into what has caused the capital budget for Transmission to increase over the past ten years in each of the subcategories is provided below.

Substation Projects

Peak load growth associated with increased electric space heating has had a significant impact on substation capacity over the past ten years. Due to this load growth, the construction of seven new substations has been necessary: UPEI Substation (2013), West St. Peter's Substation (2015), Airport Substation (2016), Bagnall Road Substation (2017), Mount Albion Substation (2018), Clyde River Substation (2020/2021) and East Royalty Substation (proposed for 2021/2022).

In addition to the electrification of space heating, a significant increase in residential construction, including numerous large multi-unit buildings, as well as new large commercial loads (Blueberry Plant expansion in Morell, and the Bio-Commons Park and Airport Industrial Park expansions in Charlottetown) has also contributed to the need for the new substations. In some cases, these substation projects required the construction of new, or the reconfiguration of existing, transmission line connections.

Investments in existing substations have also been required to replace aged and deteriorated components, address capacity issues and upgrade to current safety standards. Substations in New Annan, Wellington and Lorne Valley were rebuilt in 2011, 2019 and 2020, respectively. Several power transformer projects were also completed to avoid overload resulting from increased customer demand, including new transformers for Albany Substation (2012), Wellington Substation (2017), O'Leary Substation (2018), Airport Substation (2019) and the addition of a new mobile transformer in 2015/2016. System capacitors for the 69 kV transmission system were installed at the Charlottetown Plant and Lorne Valley Substation in 2018 and 2020, respectively. These transmission line capacitors were required due to load growth.

Projects to replace aged substation assets (e.g., 69/138 kV breakers and switches), modernize substation facilities (e.g., vandalism deterrence, automated switching, backup generation) and protect the environment (e.g., transformer oil containment) have been added in the past ten years. This has also factored into the increase in substation spending. These programs have been successful in achieving reliability improvements, and reducing safety and environmental hazards.

Increased investments in the Operations Technology (OT) Communication Network and Supervisory Control and Data Acquisition (SCADA) have also increased transmission spending in recent years. Continuous monitoring and control of real time system information is increasingly important as it facilitates the rapid identification of system problems and remote switching to improve the efficiency of outage response. As the monitoring, control and automation of the electric system becomes more reliant on operations and communication technology, investments in cybersecurity are increasingly important to ensure continuous system integrity.

Transmission Projects

Capital investment in the transmission system over the ten-year period was necessary to replace aged and deteriorated assets, and accommodate new substation projects that were necessary due to load growth, as discussed above. The construction of Y-104 from West Royalty Substation to Church Road Substation (2014 to 2016), a distance of 84 kilometers (km), was the largest transmission project in the period. Other significant transmission line projects included:

- T-13 - 2 km upgrade at the UPEI Substation (2014);
- T-15 - 3 km extension to the Airport Substation (2015);
- T-1 - 9.5 km extension to the Bagnall Road Substation (2016);
- T-8 - 10 km rebuild to the Georgetown Substation (2017);

- T-21 - 10 km rebuild to the Alberton Substation (2017);
- T-2 - 1 km extension of T-2 to the Mount Albion Substation (2018);
- Y-109 - 11.5 km extension to rebuild and reroute it to Borden-Carleton (2018);
- T-3 - 2.9 km rebuild from Borden-Carleton to Albany Substation (2019);
- Y-109 - 1.6 km rebuild from Warren Grove to Bannockburn Road (2020);
- Y-109 - 6.5 km new tap line to the Clyde River Substation (2020); and
- Y-119 - proposed 27.1 km new line to Clyde River Substation (2021).

As listed above, there were significantly more transmission line projects since 2017. The proposed completion of the Y-119 project in 2021 will result in reduced transmission line construction activity in 2022 and 2023, which is reflected in the list of future capital projects provided as IR-4 – Attachment 1 and the five-year capital budget forecast provided in the response to IR-8.

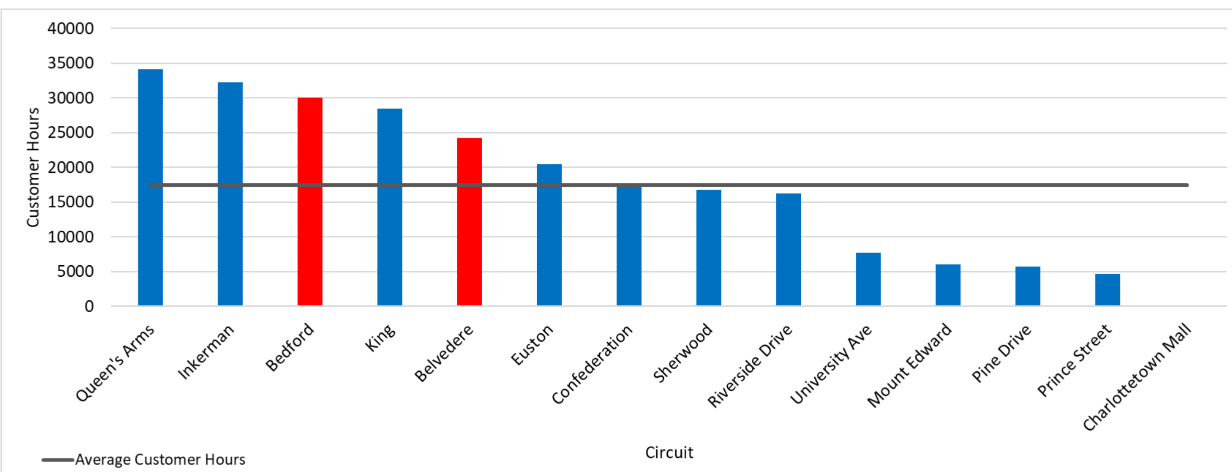
IR-17 *Section 6.1(a) - East Royalty Substation* indicates this project is needed as the current configuration lends itself to higher operation costs due to increased losses and decreased reliability to customers in the area. How does the current reliability in this area compare to other areas on the PEI electric grid?

Response:

As is typical for electric utilities such as Maritime Electric that serve a mix of urban and rural customers, urban circuits are generally more reliable than rural circuits. For this reason, the reliability of the two circuits currently serving customers in the East Royalty area is compared to circuits serving customers in the Charlottetown area. Technically, the Bedford circuit is closer to a rural circuit than an urban circuit but it has been included in the comparisons because its customers will be moved to what will be considered an urban substation.

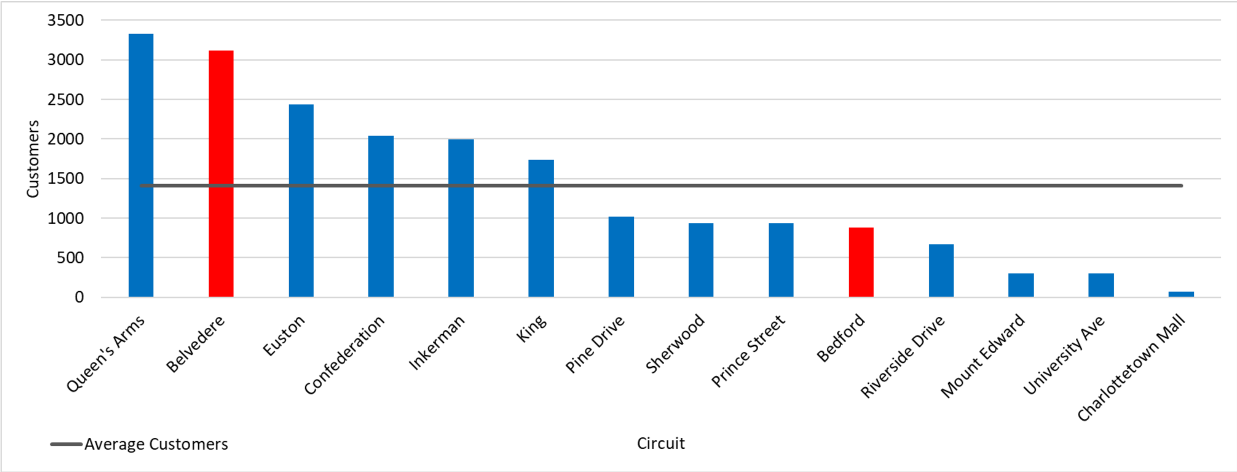
The proposed East Royalty Substation will supply power to customers in East Royalty, Suffolk, York, Bedford and areas of Scotchfort. The customers that will be supplied from the new East Royalty Substation are currently on the Bedford circuit out of the Scotchfort Substation, and the Belvedere circuit out of the UPEI Substation. Figure 1 shows that relative to other Charlottetown area circuits, outage hours on the Bedford and Belvedere circuits for the period 2015 to 2019 have been above average with both circuits in the top five for outage hours.

Figure 1: Charlottetown/East Royalty Customer Outage Hours, 2015 to 2019



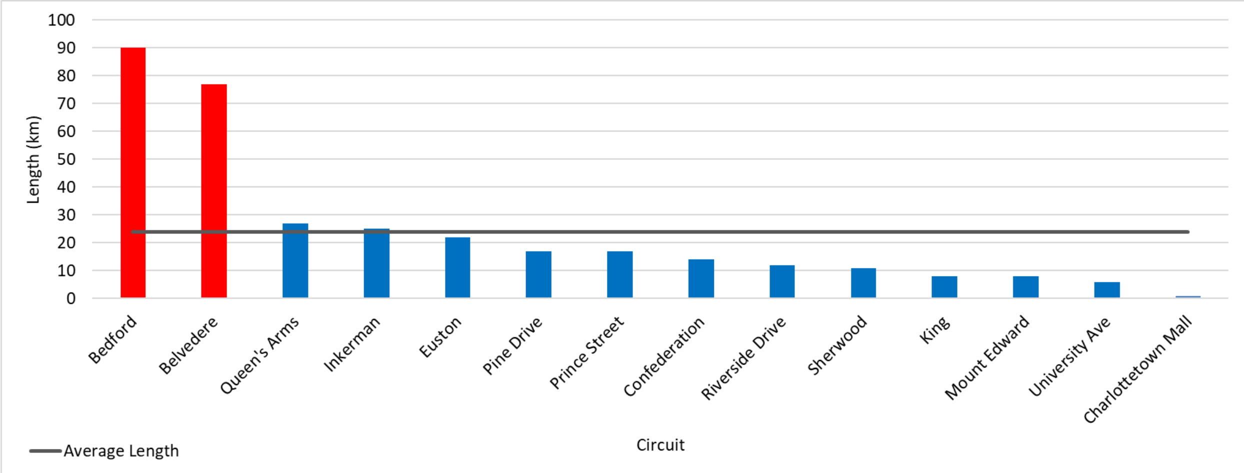
The Belvedere circuit currently serves approximately 3,120 customers with 1,680 of those customers located in Charlottetown's Sherwood area and the remaining 1,440 customers located in the East Royalty, Suffolk and York areas. Figure 2 shows that the customer count on the Belvedere circuit is currently the second highest among the Charlottetown area circuits and more than double the average number of customers per feeder in the Charlottetown area.

Figure 2: Charlottetown/East Royalty Customer Count



Total length also factors into the reliability of a circuit and Figure 3 shows that relative to other Charlottetown area circuits, Bedford and Belvedere are the two longest circuits by a considerable amount. This is directly related to the distance of their respective substations to the areas they serve. Serving loads over long distribution distances is problematic in terms of reliability, system losses[3], voltage control and being able to accommodate alternate feed options.

Figure 3: Charlottetown/East Royalty Feeder Length



In addition to the above and as provided in Section 6.1a of the 2021 Capital Budget Application, customer outage hours in the East Royalty area have increased over the last five years under the existing configuration. As shown in Figure 4, assuming East Royalty Substation had been added in 2015, the five-year average outage hours would have decreased in the area by 22 per cent, from approximately 11,000 customer outage hours to approximately 8,500 customer outage hours, by reducing the number of customers per feeder and the length of the feeders.

3 The estimated reduction in operating costs due to losses with the East Royalty Substation in service is approximately $2,760,000 over the expected 40 year life of the substation.

Figure 4: Existing and New Configuration Customer Outage Hours Comparison

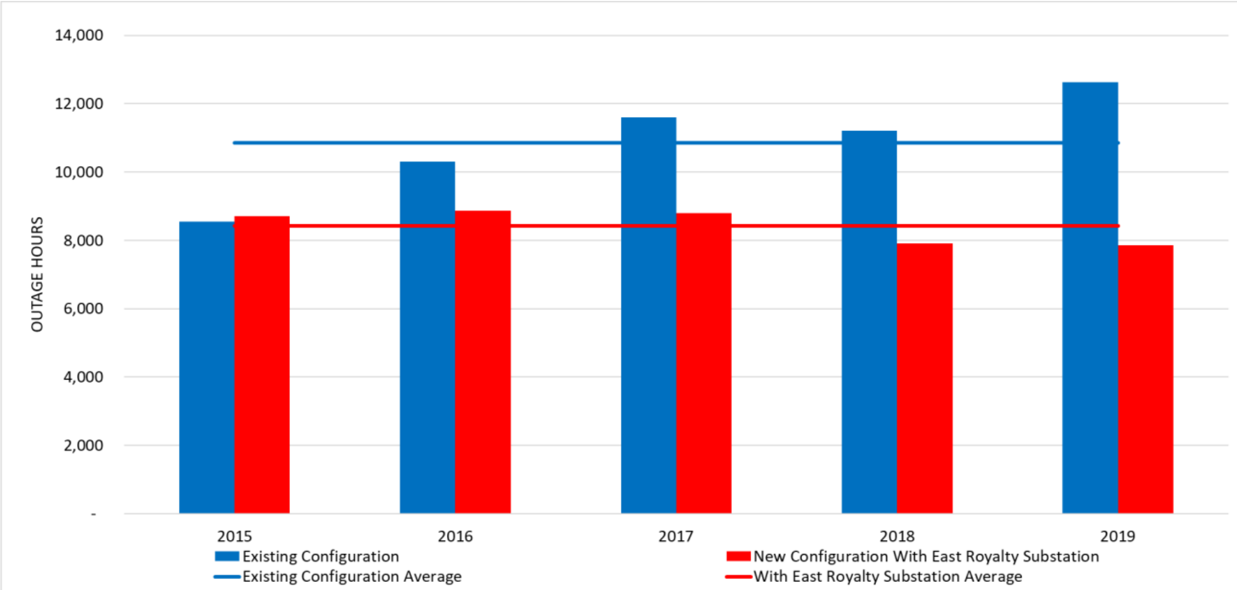


Table 1 below provides a comparison of the existing feeder configuration serving the East Royalty area to the new configuration when the proposed East Royalty Substation is in service. With the proposed new system configuration, the average customers per feeder and feeder length will be reduced by half, which will provide reliability improvements.

Table 1 Current and Proposed System Configuration for East Royalty		
Current System Configuration		
Feeder	**Customers**	**Length (km)**
Belvedere	3,119	77
Bedford	884	90
New System Configuration		
Feeder	**Customers**	**Length (km)**
Belvedere	1,681	16
Bedford	541	58
East Royalty #1	1,104	36
East Royalty #2	677	57

IR-18 *Section 6.1(c) Rattenbury Transformer Upgrade* – The purchase and installation of the Rattenbury Transformer appears to be approximately ¼ the cost of a new substation.

a. Approximately how many years before customer load will reach the capacity limit of this upgrade?

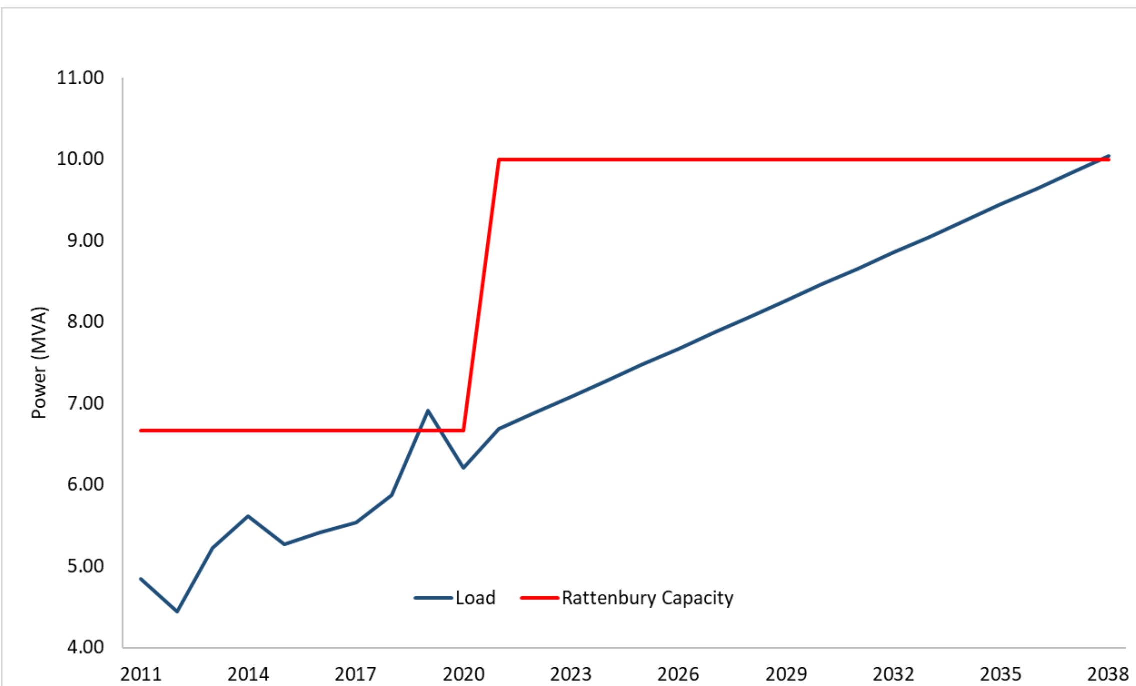
b. When will a new substation be required for this area?

c. Is it more cost effective to consider a substation sooner rather than upgrade the transformer?

Response:

a. As shown in Figure 1, the new transformer is estimated to be fully loaded by 2038, using the AAA version of the Exponential Triple Smoothing (ETS) algorithm based on the load growth from 2011 to 2020. The growth is mainly driven by summer load associated with seasonal customers and tourism.

Figure 1: Rattenbury Transformer Loading Forecast



b. There is currently no established timeframe for a new substation in the area of the existing Rattenbury Substation.

The Bagnall Road Substation was justified and constructed in 2017 based on the need to offload the Rattenbury Substation. With both Bagnall Road and Rattenbury now in service and once the proposed new transformer is installed in the Rattenbury Substation, there will be no further need to upgrade or replace either substation until it has reached its maximum capacity.

While the Integrated System Plan does not address the replacement/rebuild of the Rattenbury Substation, it does identify the possible need for a new substation in the Cavendish area in 2027 or later. As such, Maritime Electric will continue to monitor the condition of the Rattenbury Substation and assess options to best supply the Cavendish area in the future.

c. The incremental cost of a new substation (not including the transformer) compared to just installing a new transformer is estimated to be $3 million, as indicated in Table 46 on page 79 of the 2021 Capital Budget Application. With an estimated 17 years before the proposed new transformer is expected to be loaded to its maximum capacity, the existing Rattenbury Substation with the upgraded transformer is the most cost effective way to increase capacity. The Integrated System Plan and the Distribution Asset Management Plan processes will continuously monitor the condition of the Rattenbury Substation and assess the need for a new substation in the future.

IR-19 *Section 6.2(c) – Y-119 – Tap to Clyde River Substation* – MECL indicated the scope of work required for the Broadband Project in 2021 has been reduced. As a result, MECL is proposing to move up the Clyde River Tap and construction of Y-119.

a. Please provide additional justification to move up the construction of Y-119 by 2 years.

b. By moving the construction of Y-119 to the 2021 Capital Budget from the 2023 Capital Budget, does this decrease the capital budget request planned for 2023?

c. Please extend Appendix A to include estimates for years 2022 to 2026.

Response:

a. The proposed completion of Y-119 in one year instead of three years is primarily based upon the deteriorated condition of Y-109. The section of Y-109 that Y-119 will replace was constructed in 1979 and is now 42 years old. Two sections of Y-109 have already been replaced with new construction; at the western end the section from Bedeque to Mount Tryon was replaced with a new section from Borden-Carleton to Mount Tryon in 2018, and at the eastern end the section from Bannockburn Road to the steel towers in Warren Grove (a 2020 Capital Budget carryover) will be completed this year.

Y-109 was last subject to a full inspection in 2016. The inspection report is provided as IR-19 – Attachment 1. This inspection failed numerous structures (70 of 194) and identified the condition of several structures (15 of 194) to be marginal. In 2020, a visual inspection of Y-109 found that structures previously identified as failed or marginal, were further deteriorated with several poles also found to have center rot.

By the time the 2020 visual inspection was completed, the 2021 Capital Budget Application had already been submitted. When the opportunity to change the timeline of the Y-119 project in the revised 2021 Capital Budget Application became available, and it was determined that there were operational advantages and a slightly lower overall cost to a one-year project timeframe, the plans for project completion were advanced.

The benefit of completing Y-119 in 2021 is improved reliability in the near-term. Reliance on an aged Y-109 for two additional years (to 2023) puts the west and east supply of electricity at increased risk of outages due to deterioration, and does little to achieve the reliability gains that the Clyde River Substation will provide once it is being fed by a new line in prime condition.

As a reminder, the proposed Y-119 transmission line project is a least-cost alternative to rebuilding the aged and deteriorated Y-109 in place. There is limited opportunity to remove Y-109 from service (due to seasonal load constraints) and when not in service, reliability of supply to West Royalty Substation and the new Clyde River Substation would be compromised. To avoid this situation, Y-109 could be rebuilt while energized at 138 kV; however, this would involve specialized work methods and equipment that would increase the cost to approximately double what has been budgeted for Y-119. In addition to the construction cost concerns, the rebuild in-place while energized option is higher risk with respect to safety, reliability and the potential need to operate diesel generation (at a high cost) during construction. The rationale for completing the construction of Y-119 in 2021 includes construction resource availability, the deteriorated condition of the line, construction efficiency and timely use of the installed assets.

b. By moving the construction of Y-119 to a one-year (2021) completion timeframe, the forecast budget for Section 6.2 – Transmission Projects in 2022 and 2023 has been reduced accordingly (see Table 1 below). This is also reflected on the list of future capital projects, provided in IR-4 – Attachment 1.

Table 1
Forecast Transmission Line Projects Budget 2021 to 2023

Section 6.2 – Transmission Projects	2021	2022	2023
With 3-year Y-119 Project	$3,010,000	$4,020,000	$3,205,000
With 1-year Y-119 Project	$5,485,000	$2,758,000	$1,830,000

c. An extended Appendix A with estimates for years 2022 to 2026 is provided as IR-19 – Attachment 2.

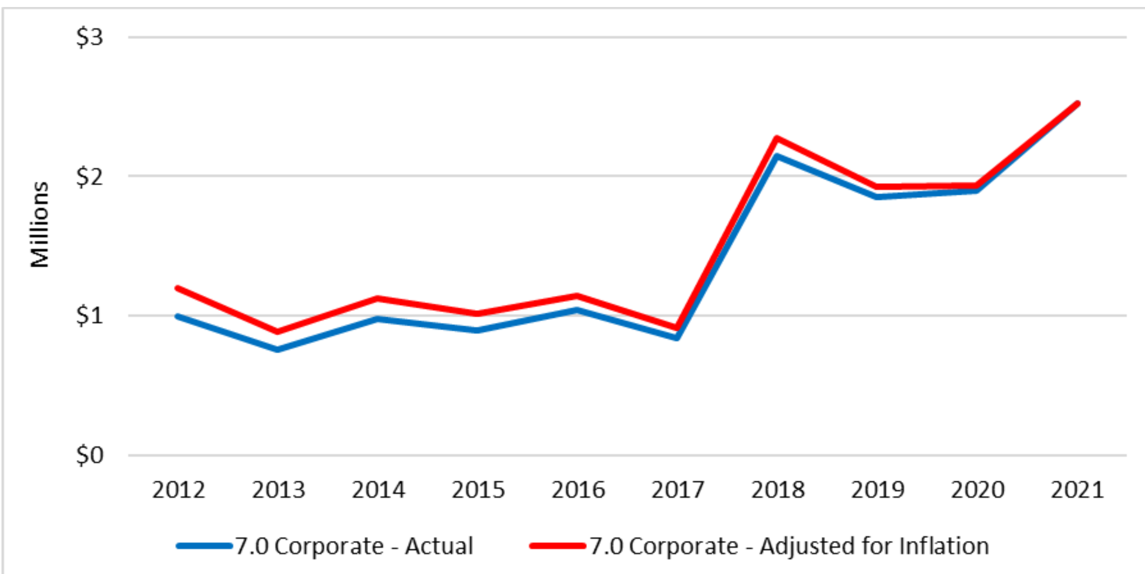
IR-20 *Section 7* – Corporate has increased significantly (approximately 150%) in the last ten years. Please explain the reason for this increase.

Response:

There are several reasons that capital investment in corporate projects has increased since 2012 including inflation of material and labour costs, and increasing reliance on information technology for administration, communication and operations across all Company departments.

Inflationary increases should be considered when comparing capital expenditures over the years to provide a more accurate reflection of any changes in system investment. When the actual expenditures are normalized for an estimated annual inflation rate of 2.0 per cent, the total Section 7 – Corporate expenditures for 2012 increases to $1,196,430 (from $997,025). This change reduces the increase over the last ten years to approximately 110 per cent. The actual and inflation adjusted capital spending on Corporate for 2012 to 2021 (as proposed) is shown in Figure 1 and the corresponding values, broken down by subcategory, are tabulated in IR-20 – Attachment 1.

Figure 1: Actual and Inflation Adjusted Capital Spending on Corporate 2012 to 2021



Inflation adjusted expenditures for Section 7.1 – Corporate Services have averaged $390,518 over the 10-year period 2012 to 2020, with annual amounts varying based upon the work required each year to upgrade Company facilities. The proposed budget for Corporate Services in 2021 is approximately $20,000 above the inflation adjusted average expenditures.

Inflation adjusted capital spending for Section 7.2 – Information Technology (IT) has increased 112 per cent from 2012 and 2021 and the proposed budget for Information Technology in 2021 is approximately $1 million above the inflation adjusted average expenditures. This is primarily due to increased spending on cybersecurity as well as vendor software agreements.

Cybersecurity investments have increased as cyberattacks have become more complex requiring risk mitigation and constant system monitoring and continual improvements. Also, in 2019, the Company's IT department incrementally expanded its scope of responsibility to include cybersecurity for the Company's operations technology (OT) network. This system is separate from the business (IT) network as it is specific to the operation and control of the electrical grid.

The increase in vendor software agreements are driven by several factors. Vendor prices have increased, the addition of new software over the period has required additional agreements, and increased user licensing for existing software has also been required (this is usually a gradual increase, however during the pandemic a large spike in "work from home" requirements caused increased licensing levels).

In addition, the 2021 Capital Budget includes a one-time cost of $330,000 to complete the Customer Information System/Billing assessment project and relatively new Cybersecurity Enhancement, Online Services and Operations Technology Network projects that were not considered imperative ten years ago.

IR-21 *Section 7.2 (c) – Customer Information System/billing* – Has MECL completed an internal review of systems used by either their parent company or other subsidiaries of Fortis? If yes, what are the results? If no, why not?

Response:

The Maritime Electric technology team meets regularly with its counterparts within the Fortis group and collaborates in many areas. The table below outlines the customer information/billing systems used at other Fortis subsidiaries. Of particular interest to Maritime Electric is the efforts of both Newfoundland Power and Central Hudson to transition from legacy, in-house developed systems.

Newfoundland Power recently received regulatory approval for their replacement and Central Hudson is in the final stages of implementing their new system.

Maritime Electric believes it is important to conduct its own full assessment of its customer information/billing systems requirements, including a current state analysis, an options/solution analysis and a financial analysis, along with the development of a request for proposal document.

Table 1 below shows the CIS vendor used by each Fortis utility. Fortis Inc. is not included because it does not have a CIS/Billing system (as it is not an operating utility).

Table 1	
Fortis Subsidiary	**CIS Vendor Used**
Newfoundland Power	Developed in House
Fortis Ontario	SAP
Fortis Alberta	SAP
Fortis BC	SAP
Tucson Electric Power	Oracle
Caribbean Utilities	Central Square
Fortis TCI	MECOMS
Central Hudson	Developed in House (implementing SAP spring 2021)

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INTERROGATORIES

IR-1 – Attachment 1

2021 Capital Budget Projects with Contingency >10%

2021 Capital Budget Projects with Contingency > 10%			
Budget Category	**Project Description**	**Contingency**	**Contingency Rationale**
4.0	**GENERATION**		
4.1	**Charlottetown Plant Buildings and Services**		
4.1a	Energy Control Centre Upgrades	12.1%	Multiple small projects; material and labour quotes based on 2020 pricing; high risk of external labour price increases above normal inflation.
4.1b	Replace Vehicle Gate and Controllers	15.9%	Material and labour quotes based on 2020 pricing; high risk of external labour price increases above normal inflation.
4.2	**Charlottetown Plant Turbine-Generator Projects**		
4.2b	CT3 Generator Breaker	17.5%	Estimate based on 2015 quotation; sole-source supplier risk.
4.2c	3,000 Amp Siemens Switchgear Breaker	16.5%	Material quotes based on 2020 pricing; all other costs were estimated.
4.3	**Borden Plant Projects**		
4.3a	Backup Power Supply for CT1 and CT2	13.8%	Estimate based on 2018 quotation; US$ exchange rate risk; high risk of external labour price increases; all items other than trailer were estimated.
4.3b	Replace CT2 Radiator Core and Oil Cooler Foundation	14.9%	Radiators and gaskets quote based on 2020 pricing; all other costs were estimated.
4.3c	CT1 Generator Breaker	27.9%	Custom sourced item based on now expired quote (may need to be sourced again and requoted); all other costs were estimated.
6.0	**TRANSMISSION**		
6.1	**Substation Projects**		
6.1g	Mobile Communications System Upgrade	13.4%	Estimates based on 2019 and 2020 quotations; risk of tower modifications being required (need for communication tower modifications not yet determined - dependent upon tower loading analysis).

I N T E R R O G A T O R I E S

IR-3 – Attachment 1

Distribution Asset Management Program

Distribution Asset Management Program

Release Date: **March 26, 2021**

Prepared By: **T&D Operations**
T&D Engineering

Table of Contents

1.0 INTRODUCTION

1.1 Maritime Electric Company, Limited

Maritime Electric Company, Limited ("Maritime Electric" or the "Company") has delivered electricity on Prince Edward Island ("PEI") since 1918. Maritime Electric's mandate is to provide a reliable service at the lowest possible cost, while maintaining a high level of customer service. Maritime Electric and its personnel are committed to providing this service in a safe and environmentally responsible manner.

Maritime Electric is an indirect, wholly-owned subsidiary of Fortis Inc. and operates under the provisions of Prince Edward Island's *Electric Power Act* and *Renewable Energy Act*. Maritime Electric owns and operates a fully integrated system providing for the purchase, generation, transmission, distribution and sale of electricity throughout Prince Edward Island. The Company's head office is located in Charlottetown with generating facilities in Charlottetown and Borden-Carleton. The Company has contractual entitlement to capacity and energy from New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau") and an agreement for the purchase of capacity and system energy from NB Power delivered via four submarine cables owned by the Province of Prince Edward Island. Through various contracts with the PEI Energy Corporation, the Company purchases the capacity and energy from 92.5 megawatts ("MW") of wind generation on PEI.

Maritime Electric's three on-Island generating stations are primarily backup supply sources. Those stations are:

- Charlottetown Thermal Generating Station ("CTGS" or "Steam Plant") - Two Generators - 40 MW
- Borden Generating Station ("BGS") - Two Generators - 40 MW
- Charlottetown Combustion Turbine No. 3 ("CT3") - One Generator - 50 MW

The primary role of Maritime Electric's on-Island generation is to supply energy in times of curtailment from off-Island energy suppliers or during transmission line outages or curtailments, on either PEI or the mainland. Other benefits of having on-Island generation include reduced purchased energy costs and the ability to provide backup for the four submarine cables connecting PEI to the mainland.

The CTGS is at the end of its useful life and there are numerous risks and costs associated with keeping the CTGS generating units operational. Maritime Electric has prepared a plan to decommission the CTGS in a staged approach starting with the older and smaller units. In accordance with the Decommissioning Plan, which was filed with the Island Regulatory and Appeals Commission ("IRAC" or the Commission") on June 28, 2018, the two largest units (Unit 9 and Unit 10) were placed into warm, long-term layup starting on March 1, 2019. These units are available to generate as required until December 31, 2021 on 90 days notice from NB Power as set out in the Energy Purchase Agreement ("EPA"). Unit 8 is now retired and has ceased providing capacity value or generating capability effective January 1, 2021.

Electricity on PEI is transmitted at 138 kilovolts ("kV") or 69 kV and travels along a network of high voltage transmission lines to substations situated across PEI. These substations reduce electricity voltage so that it can travel on smaller power lines, carrying electricity to transformers (on poles or on the ground) where the voltage is reduced again to deliver electrical power safely and efficiently to customers. There are over 6,000 kilometres ("km") of power lines on PEI with approximately 5,300 km for distribution and 720 km for transmission.

1.2 Objective

The objective of the Distribution Asset Management Program ("DAMP") is to prudently and effectively manage the planning, engineering, design, addition, inspection, maintenance, replacement, and retirement of distribution assets in a sustainable manner that maximizes safety and customer reliability, while minimizing costs, in the short and long terms.

This objective is achieved by thorough and sound planning, prudent and justified budgeting, documentation, and review of all efforts and expenditures while implementing the documented capital and operating work plans.

Maritime Electric will maintain a comprehensive DAMP which outlines the capital and operating processes, activities, and expenditures that are necessary to ensure that the Company continues to provide safe, reliable and efficient distribution of electricity to its customers.

There are three key principles that are integral to the DAMP:

a. Provide for the growth needs of the customers;
b. Provide safe, reliable, and high quality service; and
c. Satisfy the first two principles in a sustainable manner which minimizes the long term costs to be borne by the customers of Maritime Electric.

These key principles are derived from safety considerations; acts, regulations, codes and guidelines; good utility practice; and customer expectations. These are reviewed annually and adjustments are made to the DAMP based on changes in legislation, system performance, safety assessments, and customer feedback.

1.3 Scope

This document is intended to provide a summary of the DAMP at Maritime Electric. This document does not attempt to encompass all of the information and activities that fully define the management of distribution assets; however, it will provide a summary with sufficient detail to provide an understanding of the Company's asset management practices.

2.0 OVERVIEW

2.1 Distribution Substation Overview

The following overview describes the equipment installed in each substation and the loading of the transformers during summer peak and winter peak. A Single-Line Diagram for each substation and pictorial description of the area each substation feeds are also included. Distribution feeder voltages are typically to be 12.5 kV unless otherwise specified.

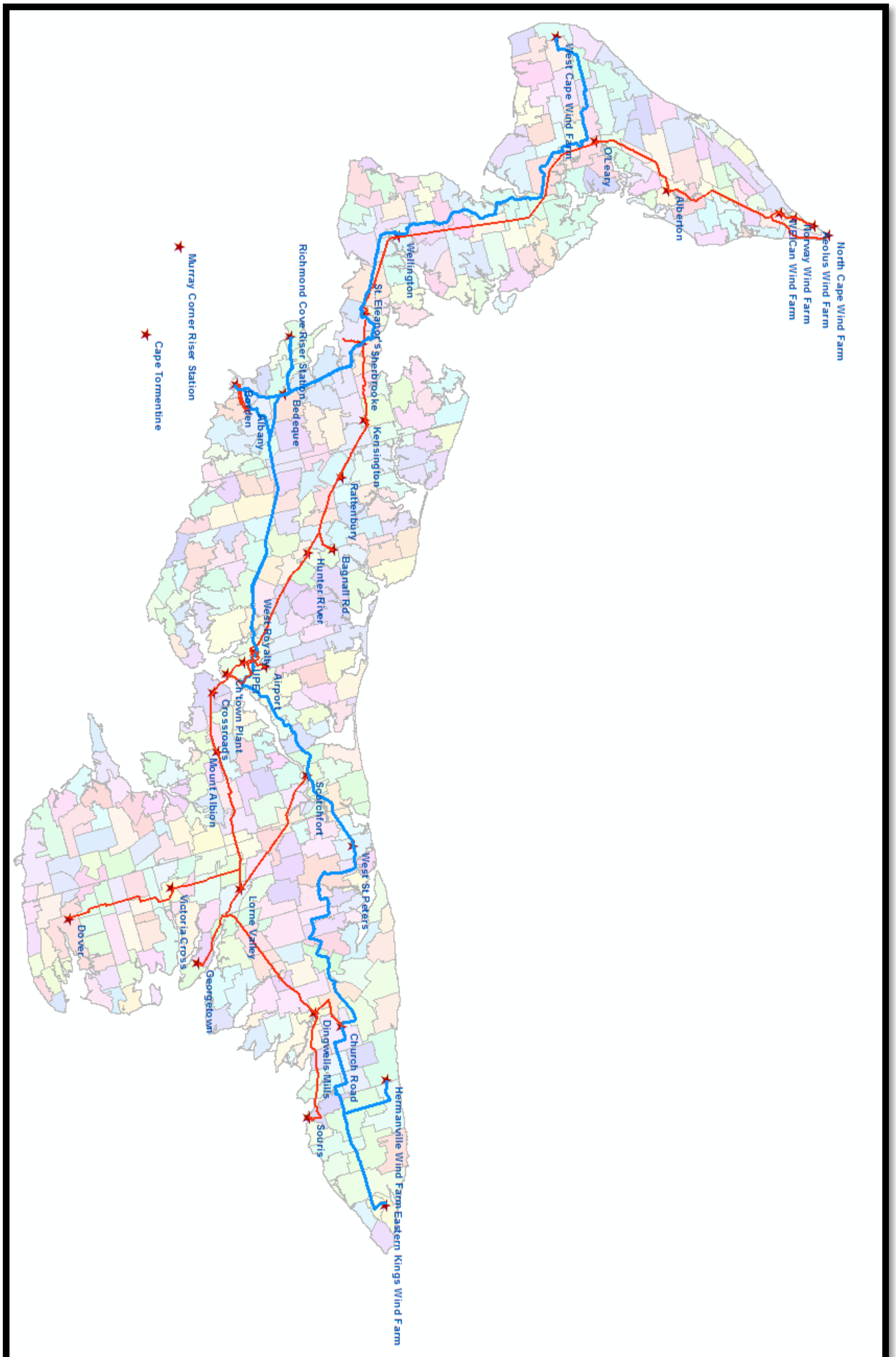
West Cape Wind Farm
O'Leary
Alberton
North Cape Wind Farm
Aeolus Wind Farm
Norway Wind Farm
Wellington
St. Eleanor's
Sherbrooke
Richmond Cove Riser Station
Bedeque
Borden
Albany
Murray Corner Riser Station
Cape Tormentine
Kensington
Rattenbury
Bagnall Rd
Hunter River
West Royalty
Airport
Ch'town Plant
Crossroads
Mount Albion
Scotchfort
West St Peters
Lorne Valley
Victoria Cross
Dover
Georgetown
Dingwells Mills
Church Road
Souris
Hermanville Wind Farm
Eastern Kings Wind Farm

Figure 1: Transmission System of Prince Edward Island

2.1a Airport Distribution System

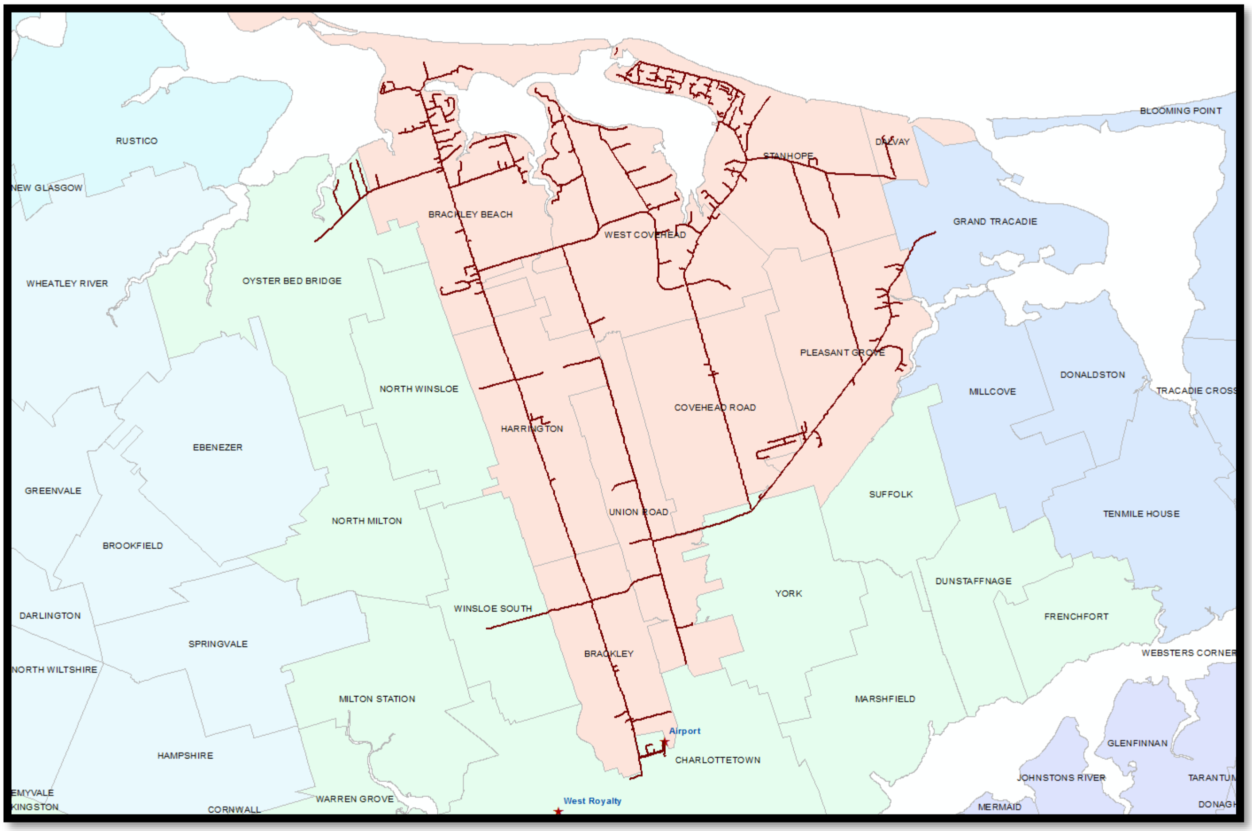

Figure 2: Service Area of Airport Substation

The Airport Substation ("AP") is located at 48 Aviation Avenue in Charlottetown. The substation is fed from 69 kV transmission line T-15 out of the West Royalty and Charlottetown Plant Substations. The substation has three circuits, Aviation Park, Covehead and Brackley. The distribution voltage at Airport Substation is 25 kV. There is one substation transformer (15/20 Megavolt Amperes ["MVA"], Company ("Co.") # 82, 2019 vintage, 69 kV – 25 kV). The substation has an on load tap changer for voltage regulation and uses bus potential transformers ("PT's") and transformer current transformers ("CT's") for metering. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 79. The summer and winter peak load is 6.79 MVA and 8.05 MVA respectively. The winter peak load represents 54 per cent of the Oil Natural Air Natural ("ONAN") rating and 40 per cent of the Oil Natural Air Forced

("ONAF") rating. If needed, and depending on load condition, this substation can be paralleled with West Royalty in order to reduce the impact of a potential outage.

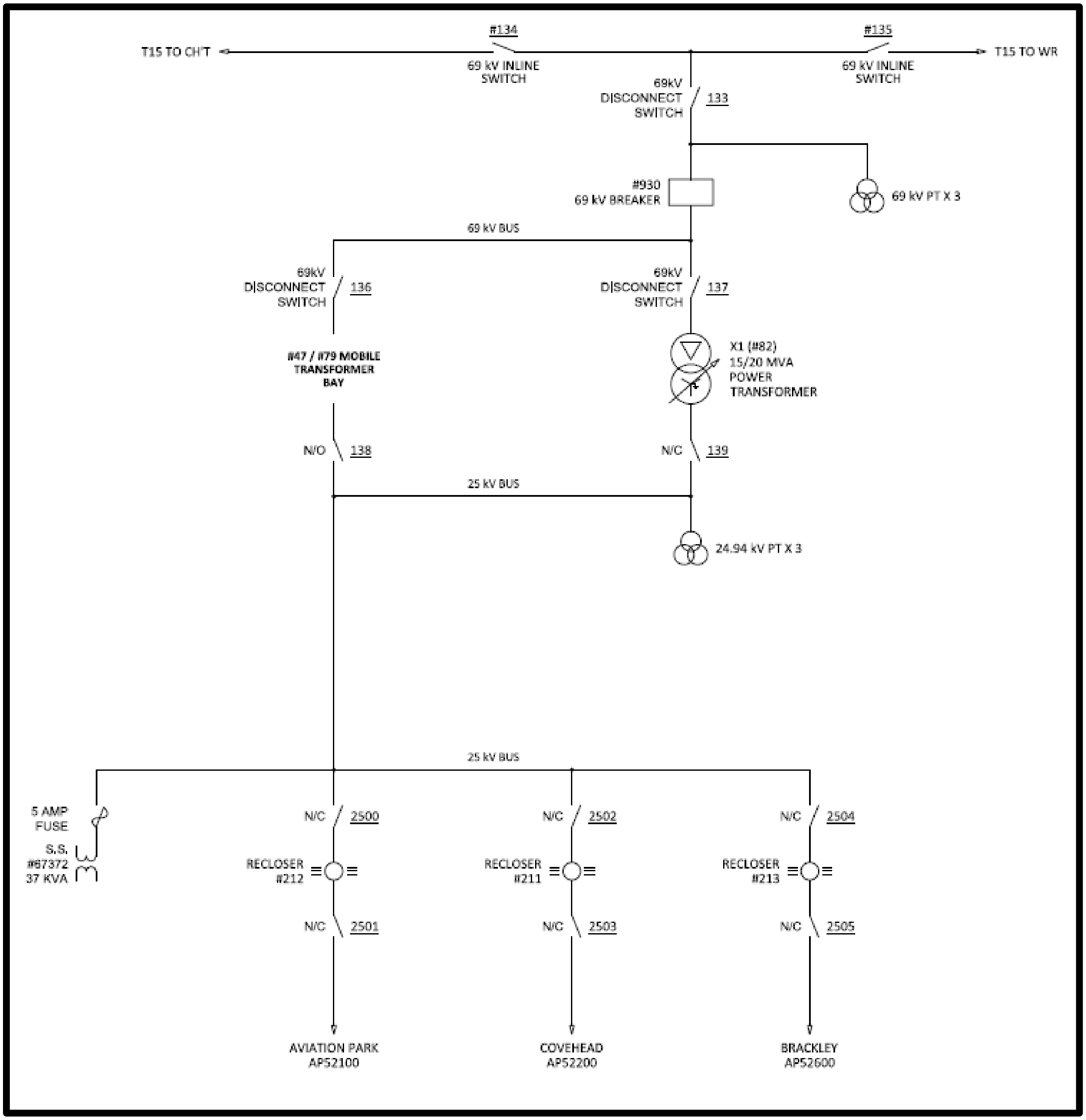

Figure 3: Single-Line Diagram of Airport Substation

2.1b Albany Distribution System

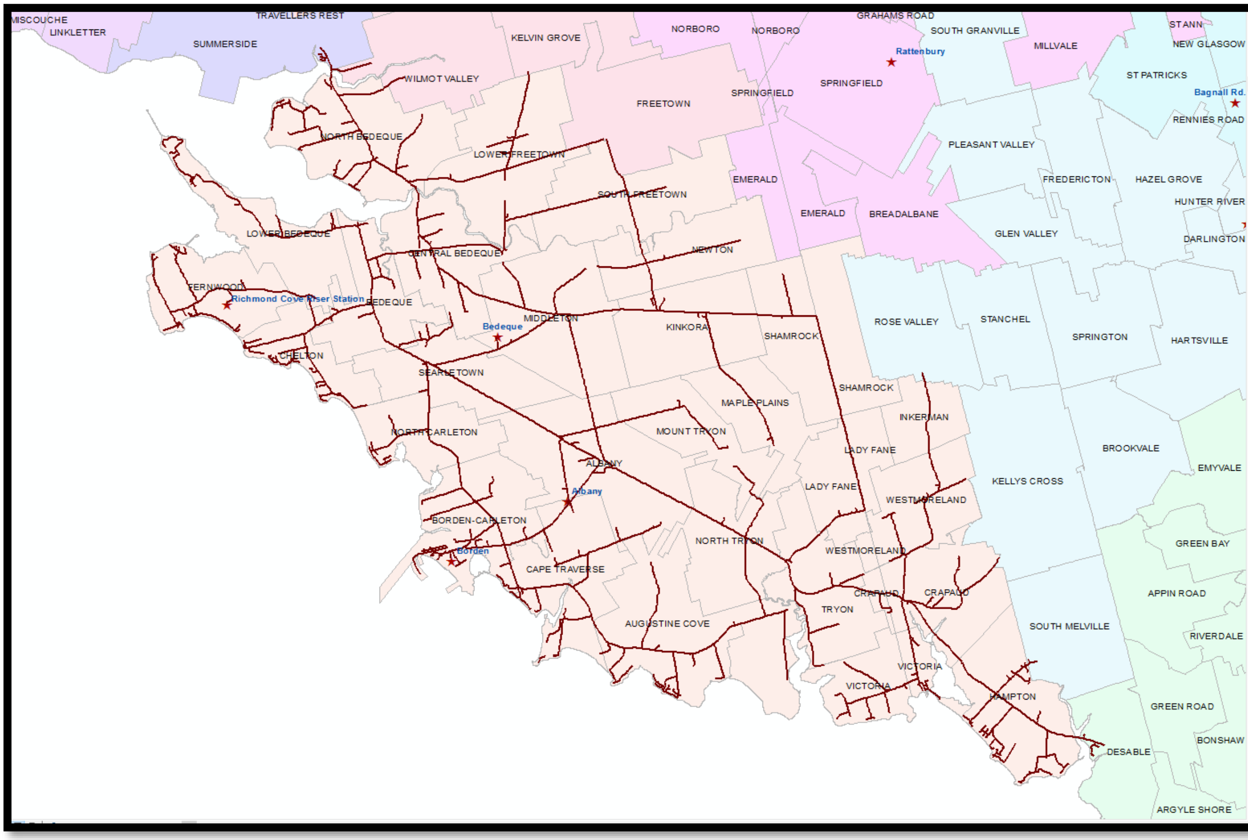

Figure 4: Service Area of Albany Substation

The Albany Substation ("AB") is located at 5 Train Station Road in Albany. The substation is fed from 69 kV transmission line T-3 out of the Borden Substation. The substation has four circuits, Augustine Cove, Crapaud, Borden Industrial Park and Bedeque. There are two substation transformers (7.5/10 MVA each: [Co.# 43, 2007 vintage, 69 kV – 12.5 kV] and [Co.# 82, 2019 vintage, 69 kV – 25 kV/12.5 kV]) that are paralleled. The substation has two sets of voltage regulators (rated 437 Amperes ["A"]) and two metering tanks. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. The summer and winter peak load is 11.22 MVA and 14.14 MVA respectively. The winter peak load represents 94 per cent of the combined ONAN rating and 71 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Kensington in order to reduce the impact of a potential outage.

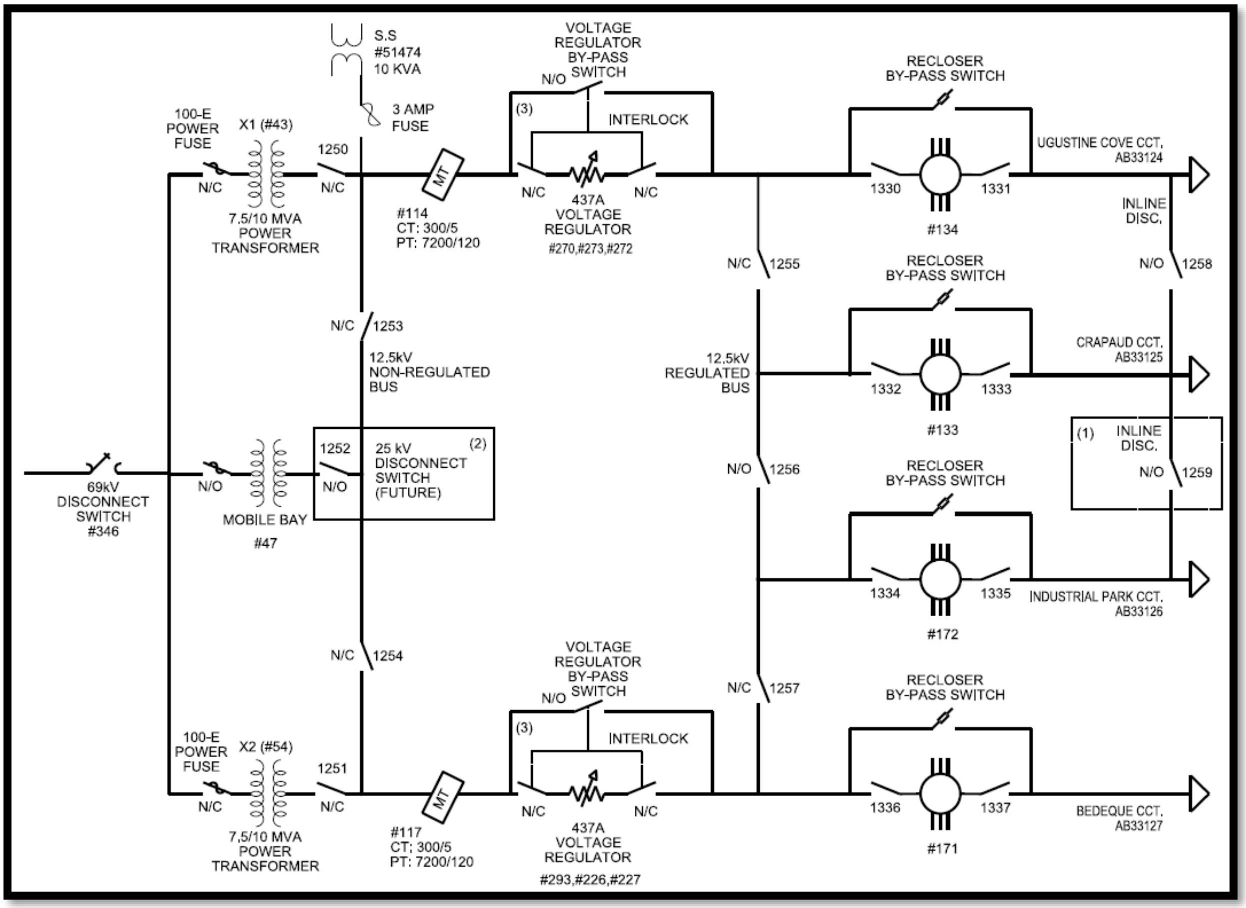

Figure 5: Single-Line Diagram of Albany Substation

2.1c Alberton Distribution System

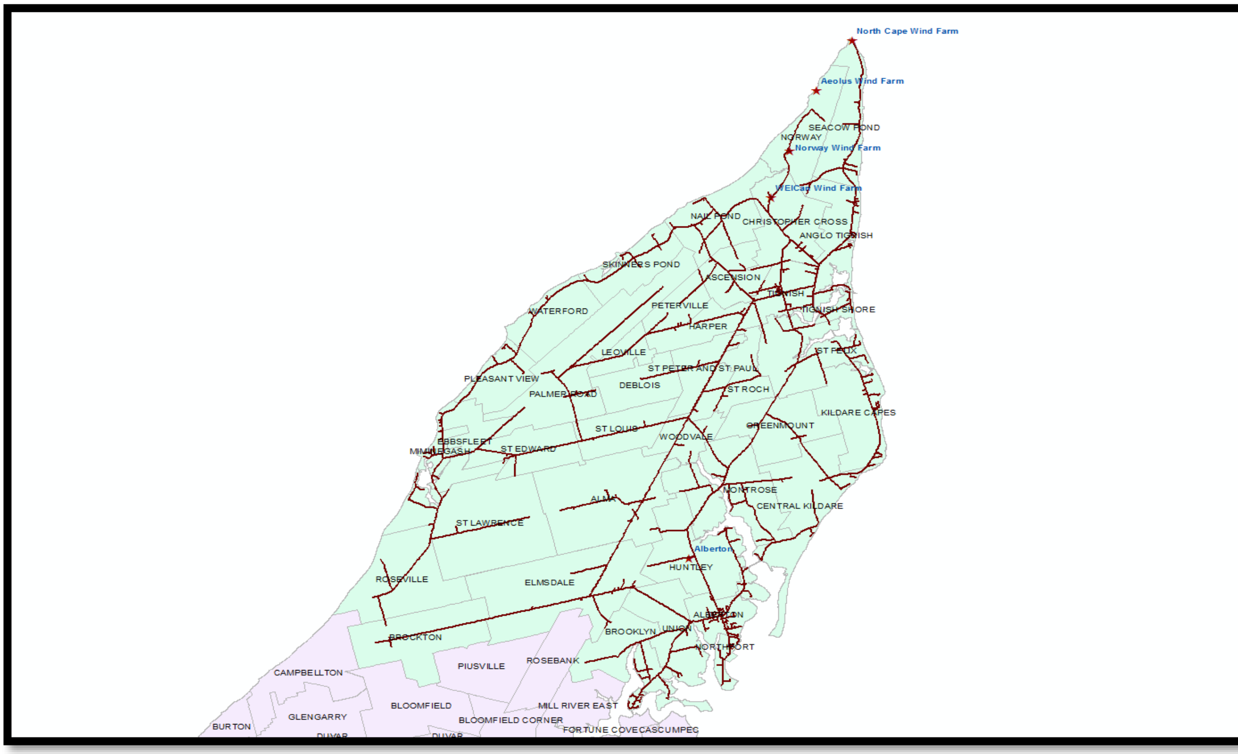

Figure 6: Service Area of Alberton Substation

The Alberton Substation ("AL") is located at 53 Oliver Road in Huntley. The substation is fed from 69 kV transmission line T-21 out of the Wellington Substation. The substation has two circuits, Tignish and Town of Alberton. There are two substation transformers ([Tignish - 7.5/10 MVA, Co.# 46, 1979 vintage, 69 kV – 12.5 kV] and [Alberton - 4/5.3 MVA, Co.# 32, 1972 vintage, 69 kV – 25 kV/12.5 kV]) that are not paralleled. The substation has two sets of voltage regulators (rated 219 A and 437 A) and two metering tanks. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. On the Tignish transformer, the summer and winter peak load is 6.56 MVA and 7.94 MVA respectively, with the winter peak representing 106 per cent of it is ONAN rating and 79 per cent of its ONAF rating. On the Alberton transformer, the summer and winter peak load is 2.98 MVA and 4.28 MVA respectively, representing 107 per cent of it is ONAN rating and 80 per cent of its ONAF rating.

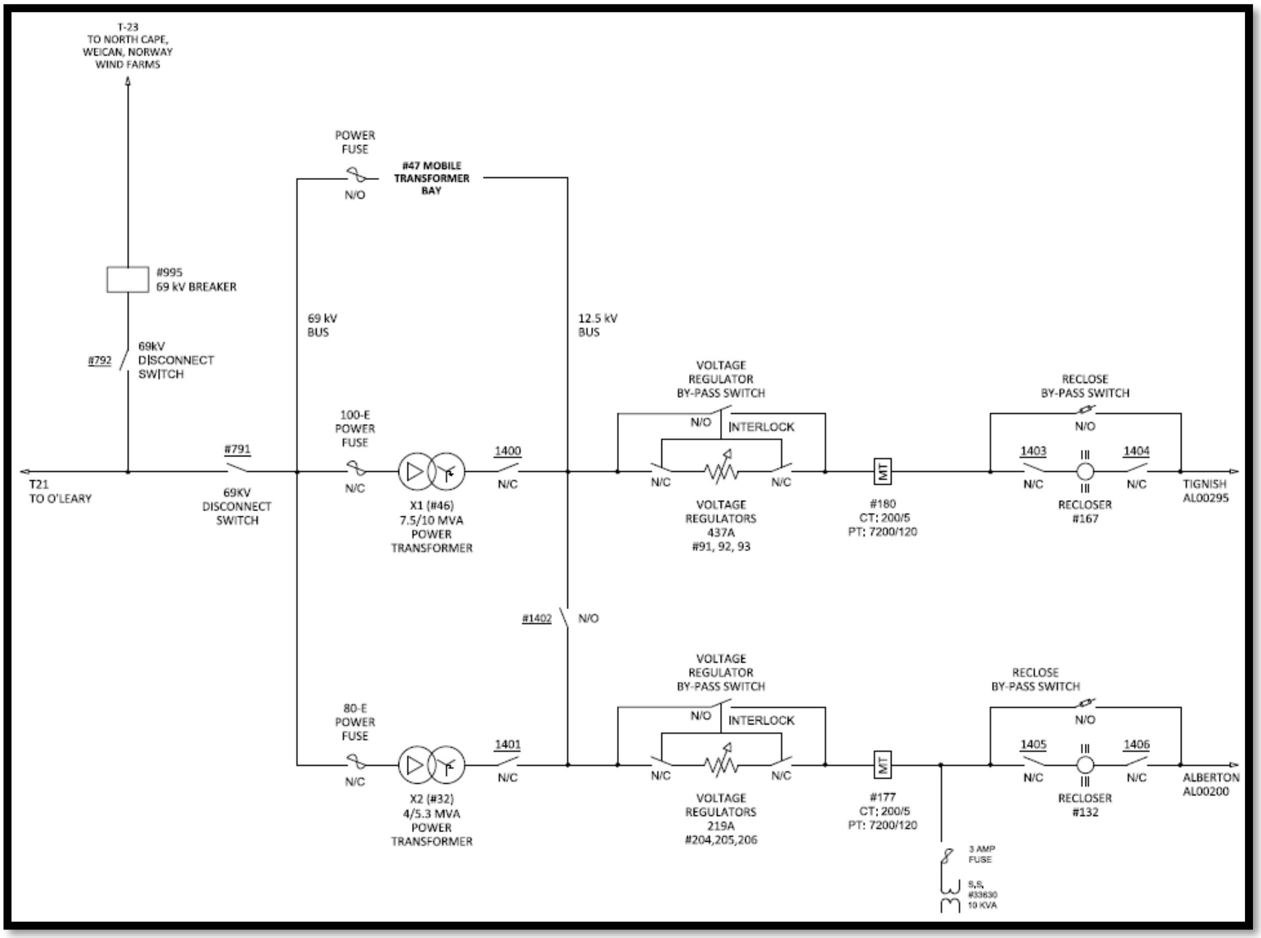

Figure 7: Single-Line Diagram of Alberton Substation

2.1d Bagnall Road Distribution System

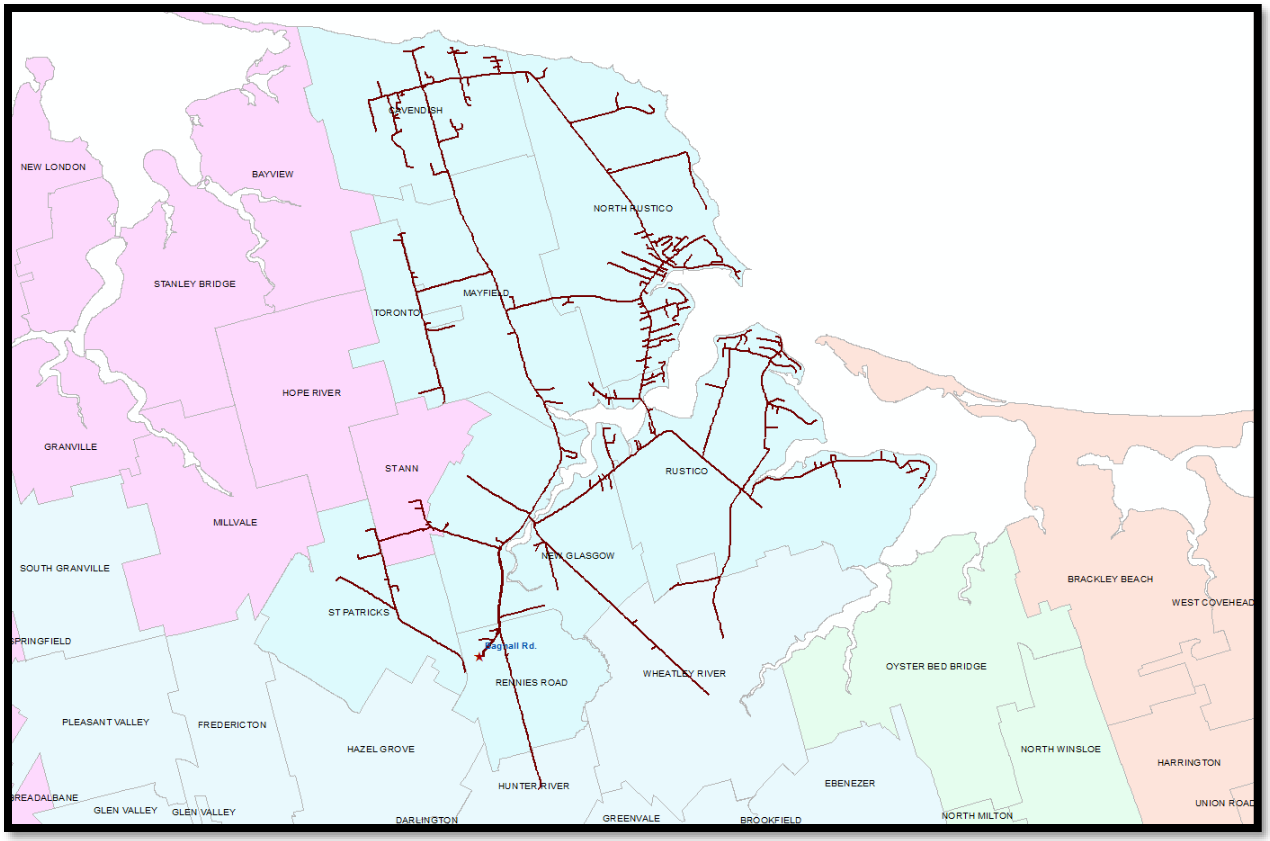

Figure 8: Service Area of Bagnall Road Substation

The Bagnall Road Substation ("BG") is located at 23 Bagnall Road in Rennies Road. The substation is fed from 69 kV transmission line T-1 out of the West Royalty Substation or the Sherbrooke Switching Station[1]. The substation has three circuits, Bayview, Cymbria and Cavendish. A transfer bus is present, which allows for any recloser to be taken out of service for maintenance without causing any customer outages. There is one substation transformer (7.5/10 MVA, Co.# 78, 2016 vintage, 69 kV – 12.5 kV). The substation has an on load tap changer for voltage regulation and uses bus potential transformers/transformer current transformers for metering. The substation is equipped with mobile transformer bay, and can accept mobile transformer Co.# 79. The summer and winter peak load is 7.71 MVA and 4.99 MVA respectively. The summer peak represents 103 per cent of the ONAN

1 Maritime Electric differentiates a switching station from a substation on the basis that transformer conversion to a distribution voltage must occur for a facility to be called a "substation".

rating and 77 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Hunter River and/or Rattenbury in order to reduce the impact of a potential outage.

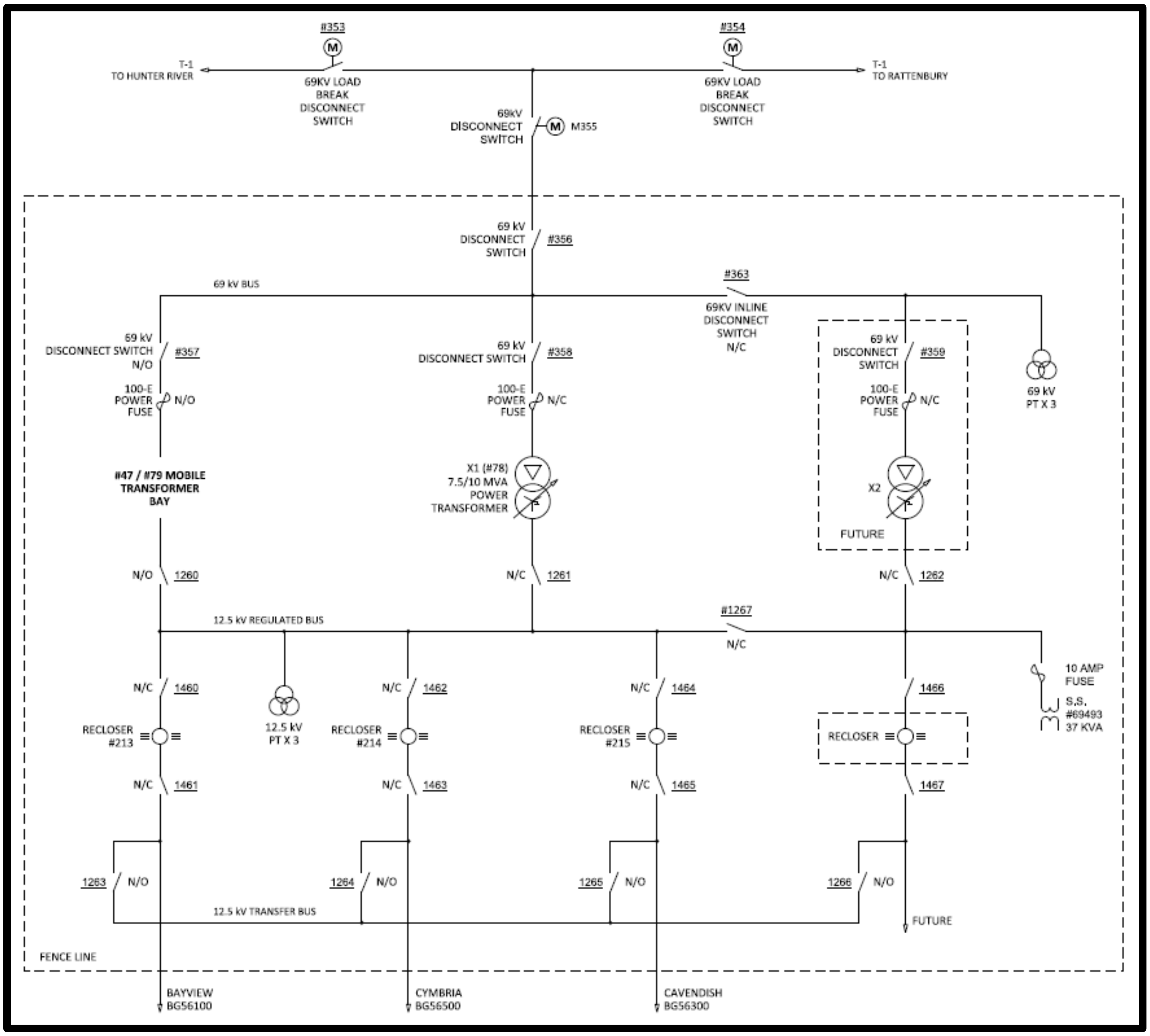

Figure 9: Single-Line Diagram of Bagnall Road Substation

2.1e **Charlottetown Distribution System**

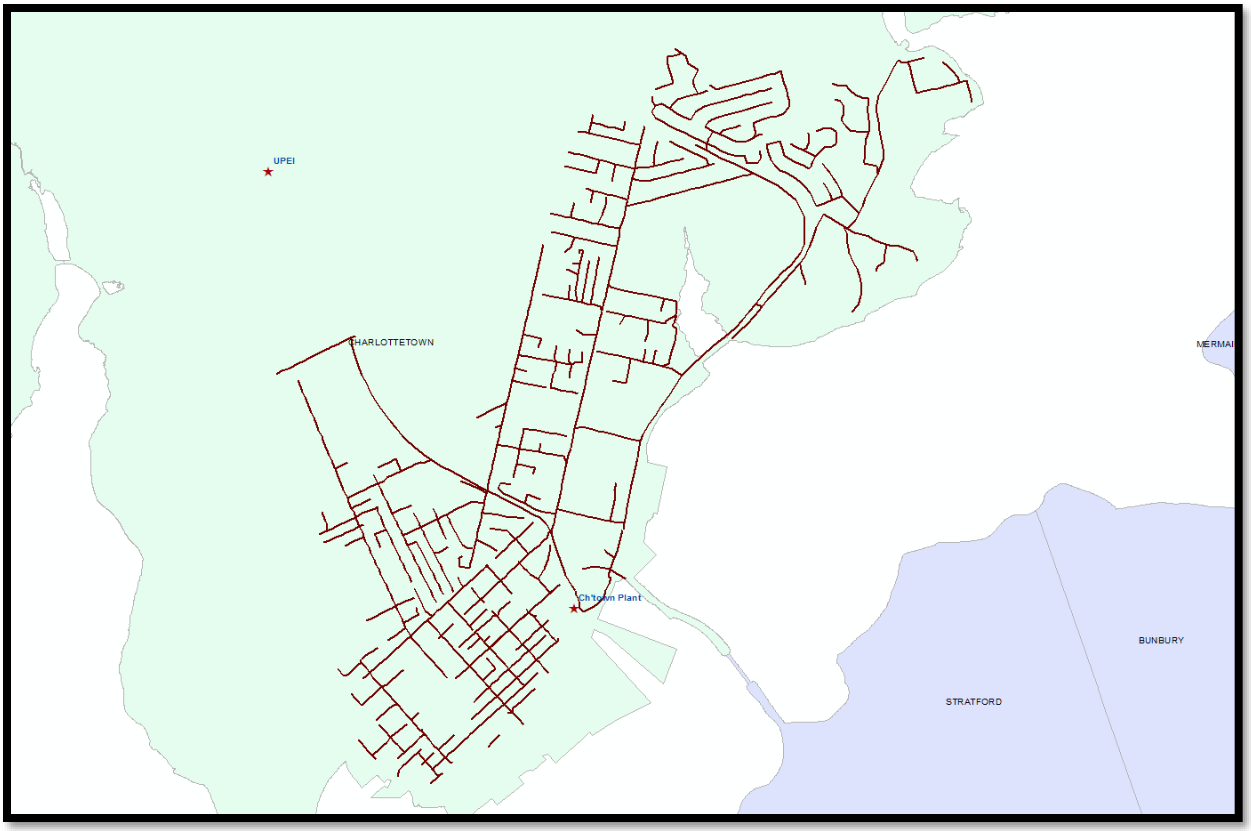

Figure 10: Service Area of Charlottetown Plant Substation

The Charlottetown Plant Substation ("CP") is located at 50 Cumberland Street in Charlottetown. The substation is fed from two 69 kV transmission lines (T-13 and T-15) out of the West Royalty Substation. The Charlottetown Plant Substation in turn feeds one 69 kV transmission line (T-2) which terminates at the Lorne Valley Switching Station.

The Charlottetown Plant Substation is unique in that it has two distribution voltages 13.8 kV and 4.16 kV and the bus work for these distribution feeders is housed within metal clad switchgear which is also used to supply station service and large motor feeds to the adjacent Charlottetown Thermal Generating Station.

One 45/60 MVA substation transformer (X4, Co.# 63, 2005 vintage, 69 kV – 13.8 kV) supplies five 13.8 kV Charlottetown area distribution circuits, Euston Street, Riverside Drive, King Street, Prince Street and Confederation. The substation has an on load tap changer for voltage regulation and the metal clad switchgear is equipped with CTs and PTs to provide individual feeder metering. The substation does not have a mobile transformer bay. If needed customers can be supplied from an adjacent substation (UPEI or West Royalty) or from CT3 directly. The summer and winter peak load for the 13.8 kV distribution is 29.9 MVA and 29.9 MVA respectively. The peak load represents 66 per cent of the ONAN rating and 50 per cent of the ONAF rating.

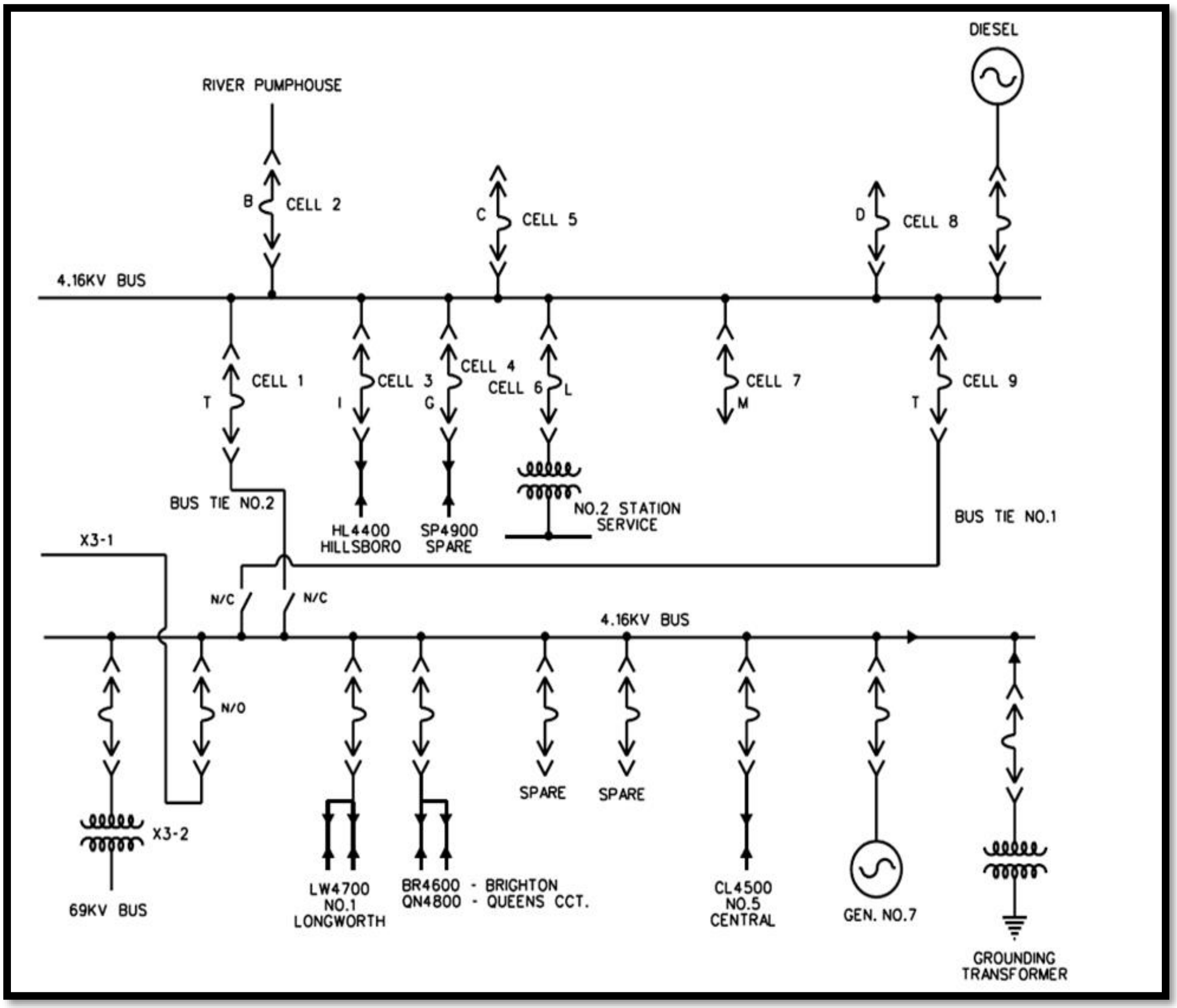

Figure 11: Single-Line Diagram of Charlottetown Plant Substation 4.16 kV Distribution System

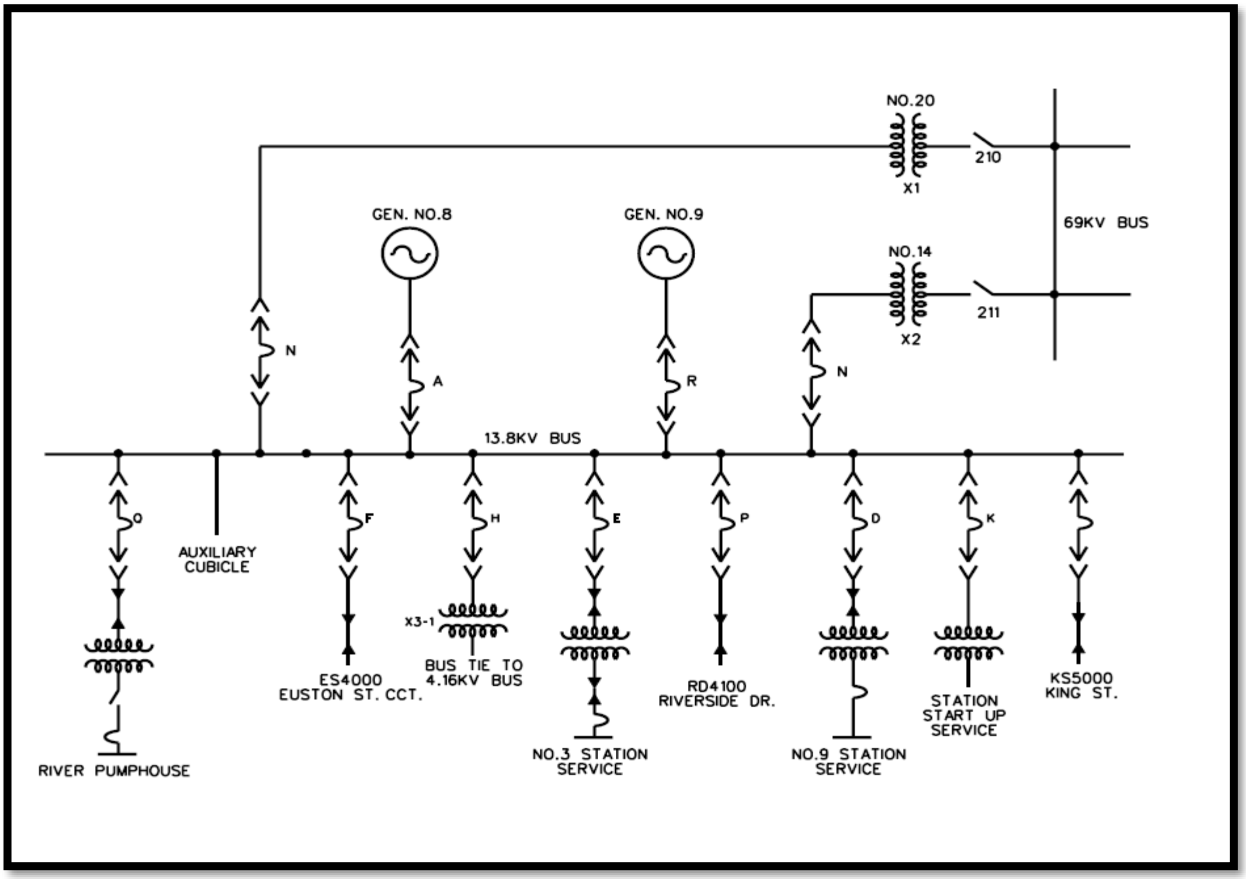

Figure 12: Single-Line Diagram of Charlottetown Plant Substation 13.8 kV Distribution System

2.1f Crossroads Distribution System

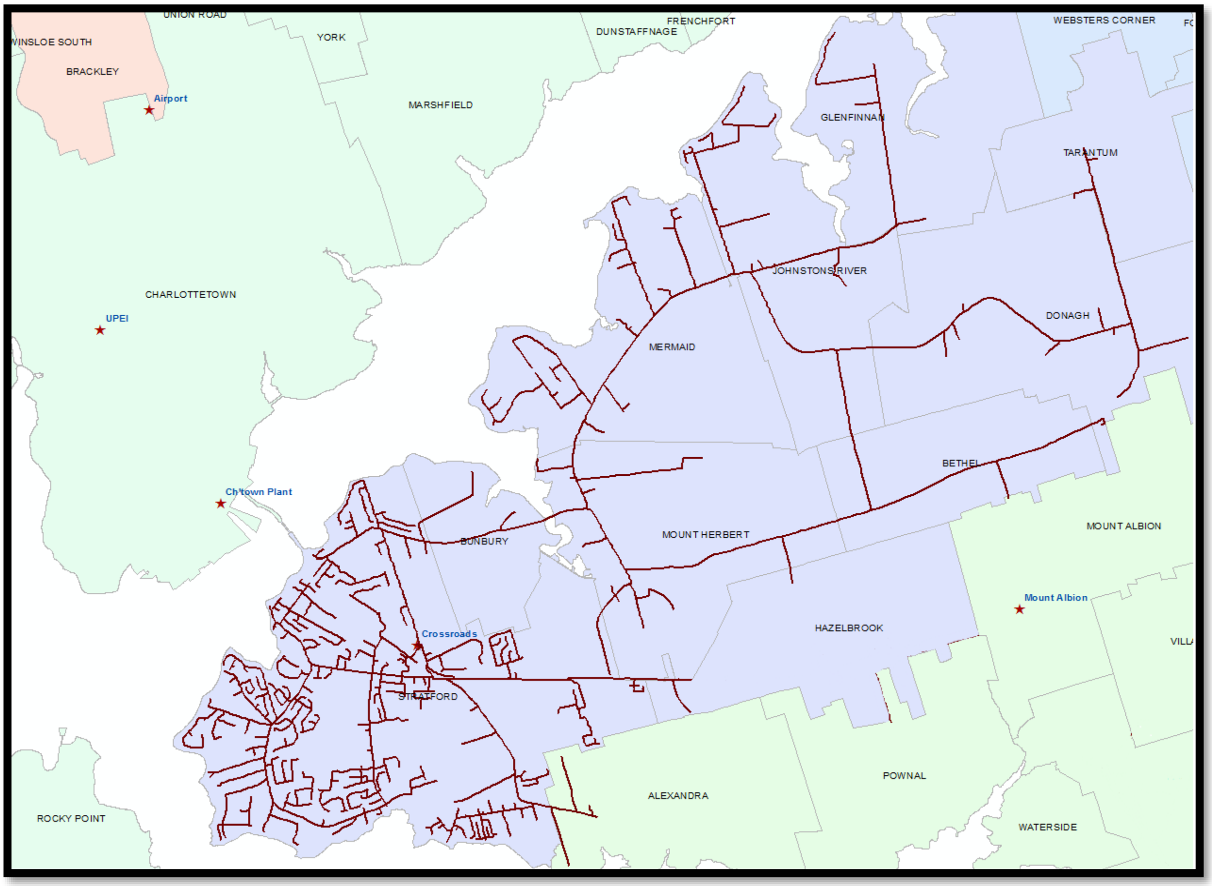

Figure 13: Service Area of Crossroads Substation

The Crossroads Substation ("CR") is located at 110 Mason Road in Stratford. The substation is fed from 69 kV transmission line T-2 out of the Charlottetown Plant Substation and the Lorne Valley Switching Station. The substation has four circuits, Kinlock, Bunbury, Tea Hill/Pownal and Southport. There are two 7.5/10 MVA substation transformers that are paralleled ([Co.# 64, 2005 vintage, 69 kV – 12.5 kV] and [Co.# 66, 2007 vintage, 69 kV – 12.5 kV]). The substation has four sets of voltage regulators (three sets are 437 A, one set is 328 A) and a metering tank. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. The summer and winter peak load is 10.0 MVA and 17.2 MVA respectively. The winter peak represents 115 per cent of the combined ONAN rating and 86 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Mount Albion in order to reduce the impact of a potential outage.

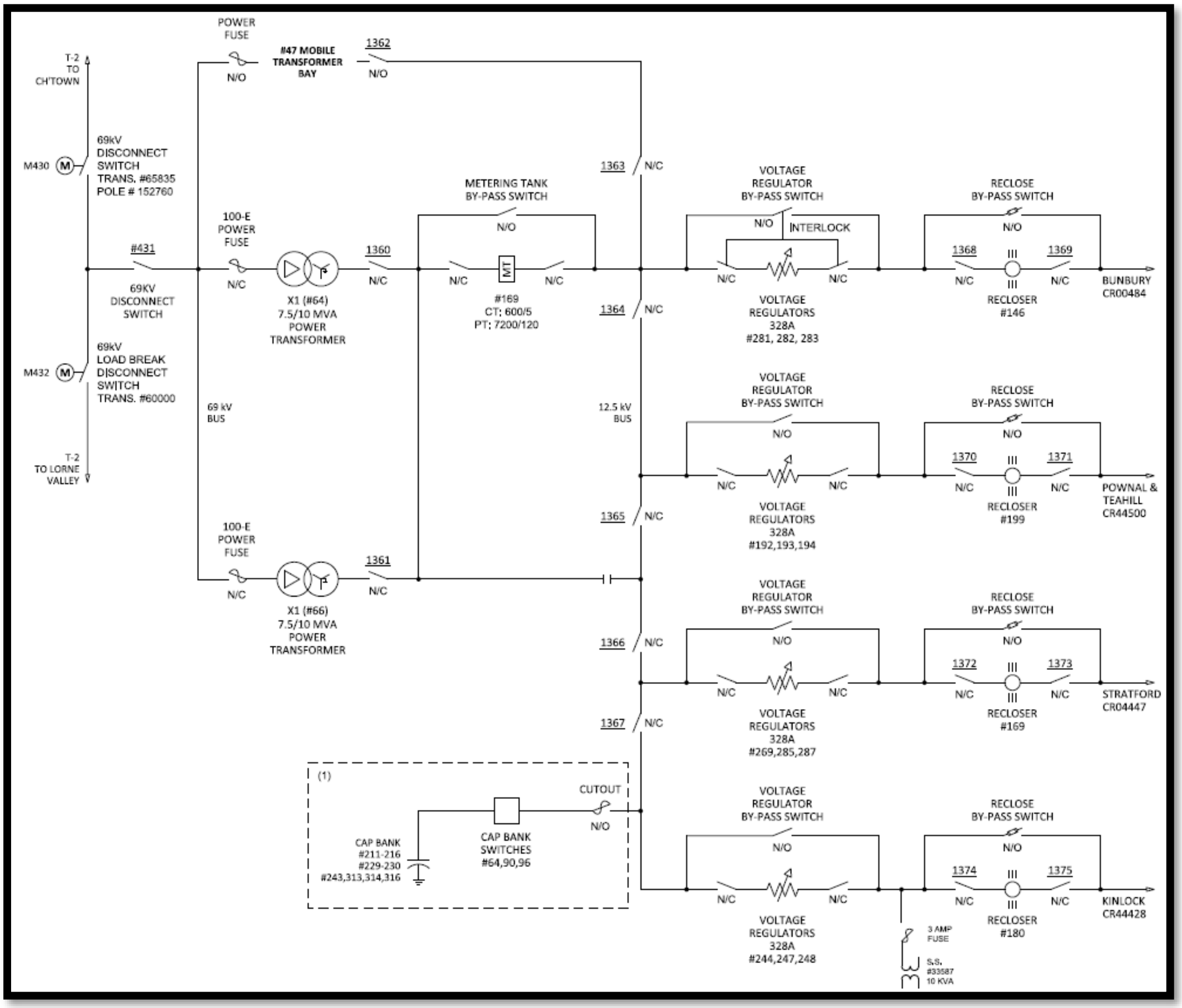

Figure 14: Single-Line Diagram of Crossroads Substation

2.1g Dingwells Mills Distribution System

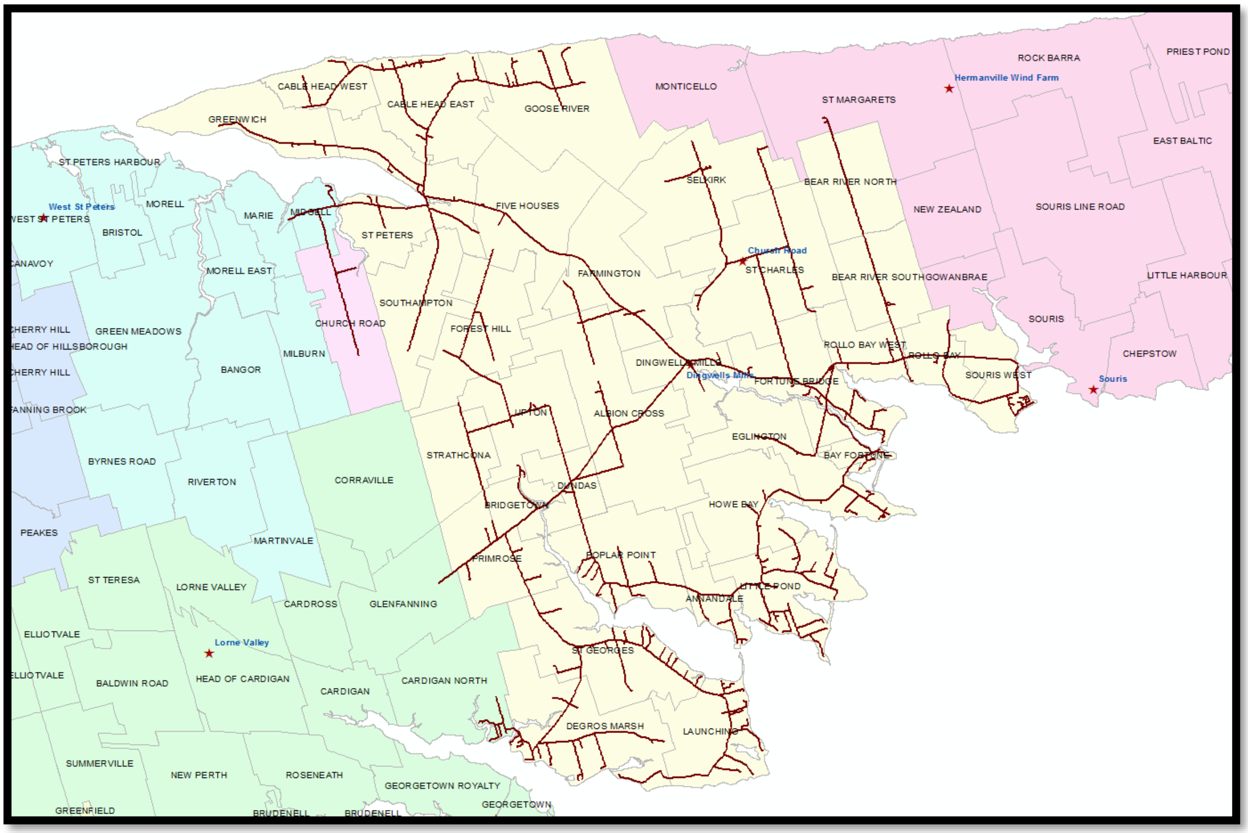

Figure 15: Service Area of Dingwells Mills Substation

The Dingwells Mills Substation ("DM") is located at 1740 Fortune Road, Route 332 in Dingwells Mills. The substation is fed from 69 kV transmission line T-8 out of the Church Road and Lorne Valley Switching Stations. The substation has three circuits, Souris, Dundas and St. Peters. The substation has one set of voltage regulators (rated 328 A) and one metering tank. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. There is one substation transformer (rated 5/6.7 MVA, Co.# 35, 1973 vintage, 69 kV – 12.5 kV) that has a summer peak load of 3.8 MVA and winter peak load of 5.2 MVA. This represents 104 per cent of the ONAN rating and 78 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with West St. Peters in order to reduce the impact of a potential outage.

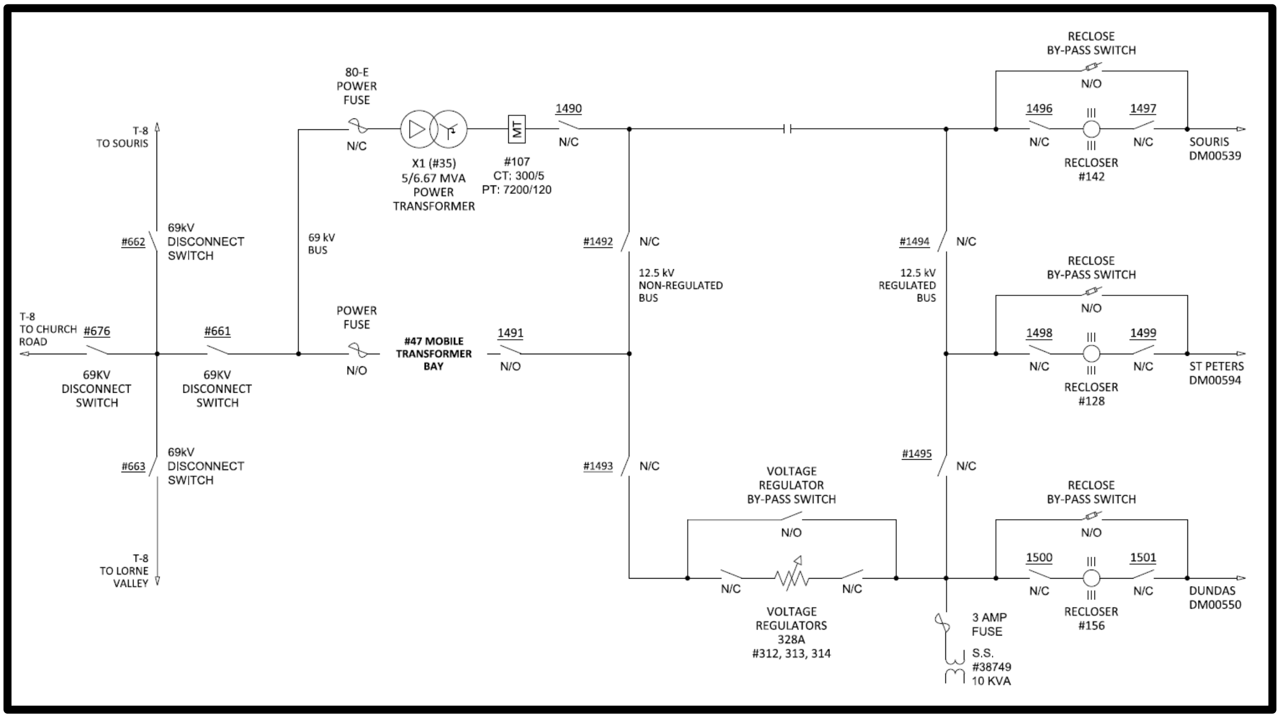

Figure 16: Single-Line Diagram of Dingwells Mills Substation

2.1h Dover Distribution System

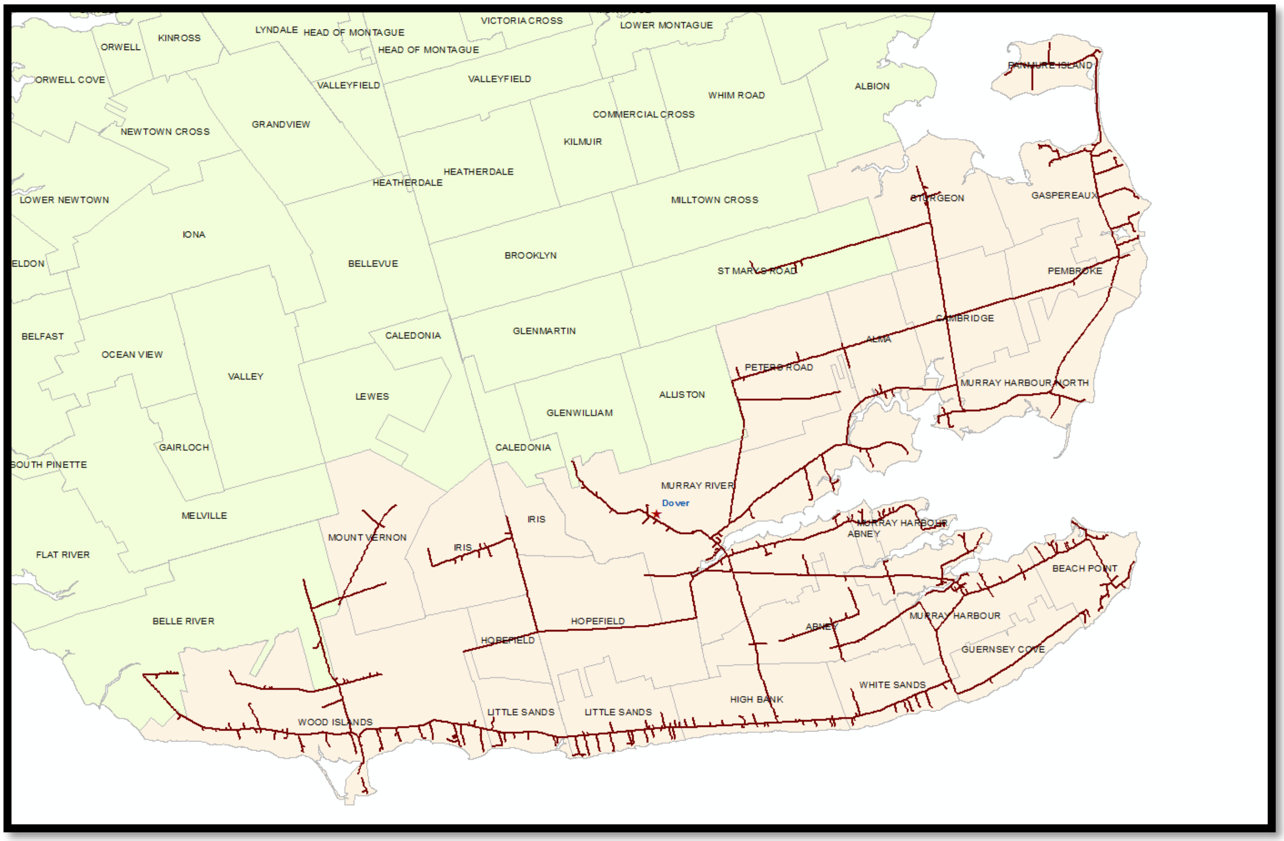

Figure 17: Service Area of Dover Substation

The Dover Substation ("DV") is located at 374 Dover Road, along Route 24 in Dover. The substation is fed from 69 kV transmission line T-10 out of the Lorne Valley Switching Station. The substation has two circuits, Wood Islands and Greek River. There is one 5/6.67 MVA (Co.# 25, 1967 vintage, 69 kV – 25 kV / 12.5 kV) substation transformer, one set of voltage regulators (rated 219 A) and a metering tank. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. The summer and winter peak load is 3.7 MVA and 4.5 MVA respectively. The winter peak represents 90 per cent of the ONAN rating and 67 per cent of the ONAF rating.

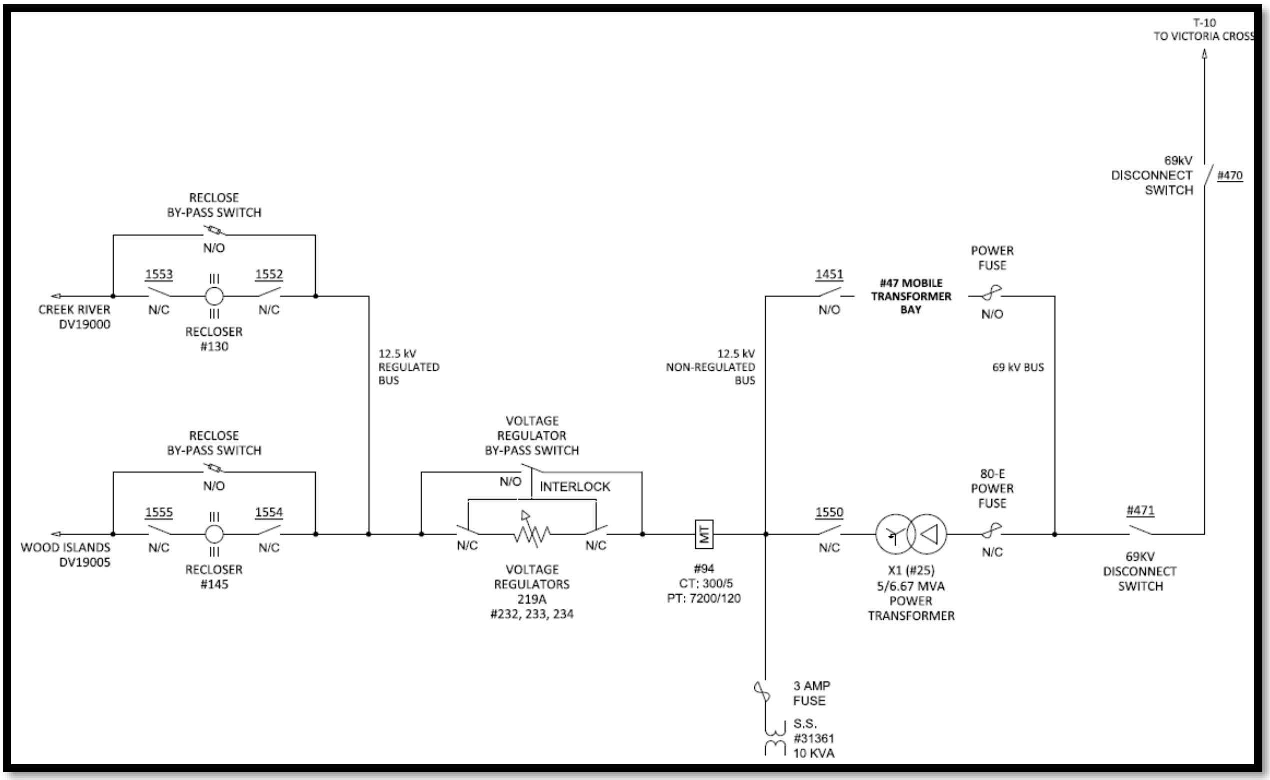

Figure 18: Single-Line Diagram of Dover Substation

2.1i Georgetown Distribution System

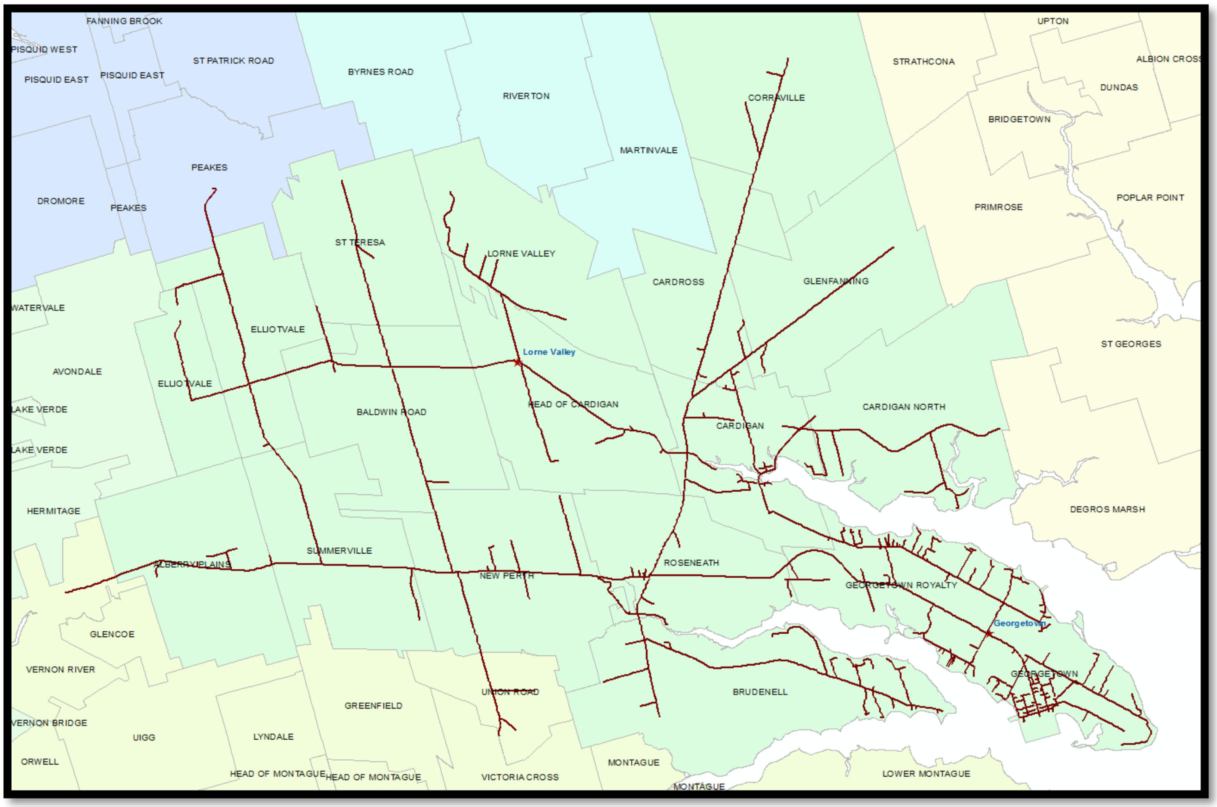

Figure 19: Service Area of Georgetown Substation

The Georgetown Substation ("GT") is located at 8 Morrisons Beach Road in Georgetown. The substation is fed from 69 kV transmission line T-8 out of the Church Road and Lorne Valley Switching Stations. The substation has two distribution circuits, Georgetown and Poole's Corner. There is one transformer (7.5/10 MVA, Co.# 60, 2000 vintage, 69 kV – 12.5 kV) in the substation. The substation has one set of voltage regulators (rated 328 A) and one metering tank. The summer and winter peak loads of 4.8 MVA and 5.7 MVA respectively are lower than historical highs due to the closure of some industrial customers in the area including a fish plant, a saw mill and a shipbuilding facility. The Georgetown Substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The winter peak load represents 76 per cent of the ONAN rating and 57 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Mount Albion and/or Victoria Cross in order to reduce the impact of a potential outage.

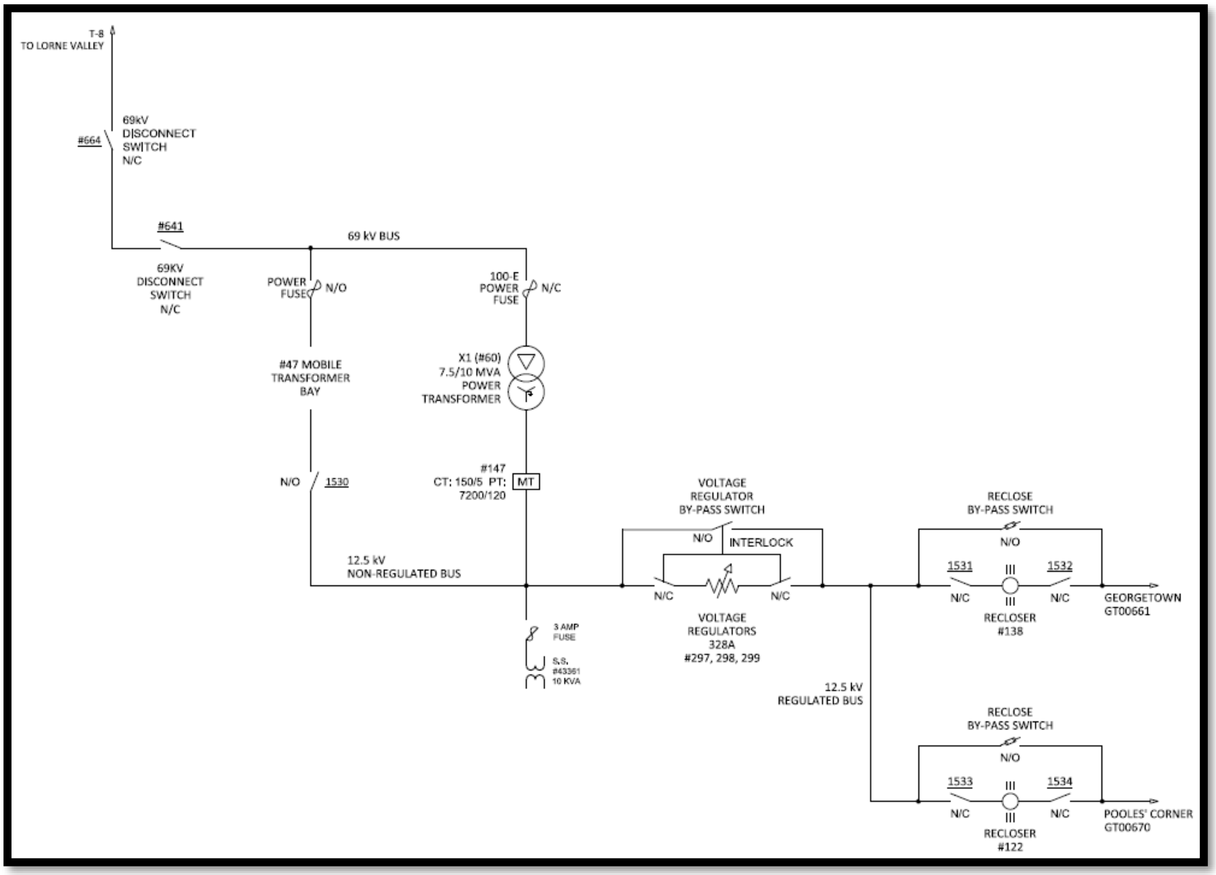

Figure 20: Single-Line Diagram of Georgetown Substation

2.1j **Hunter River Distribution System**

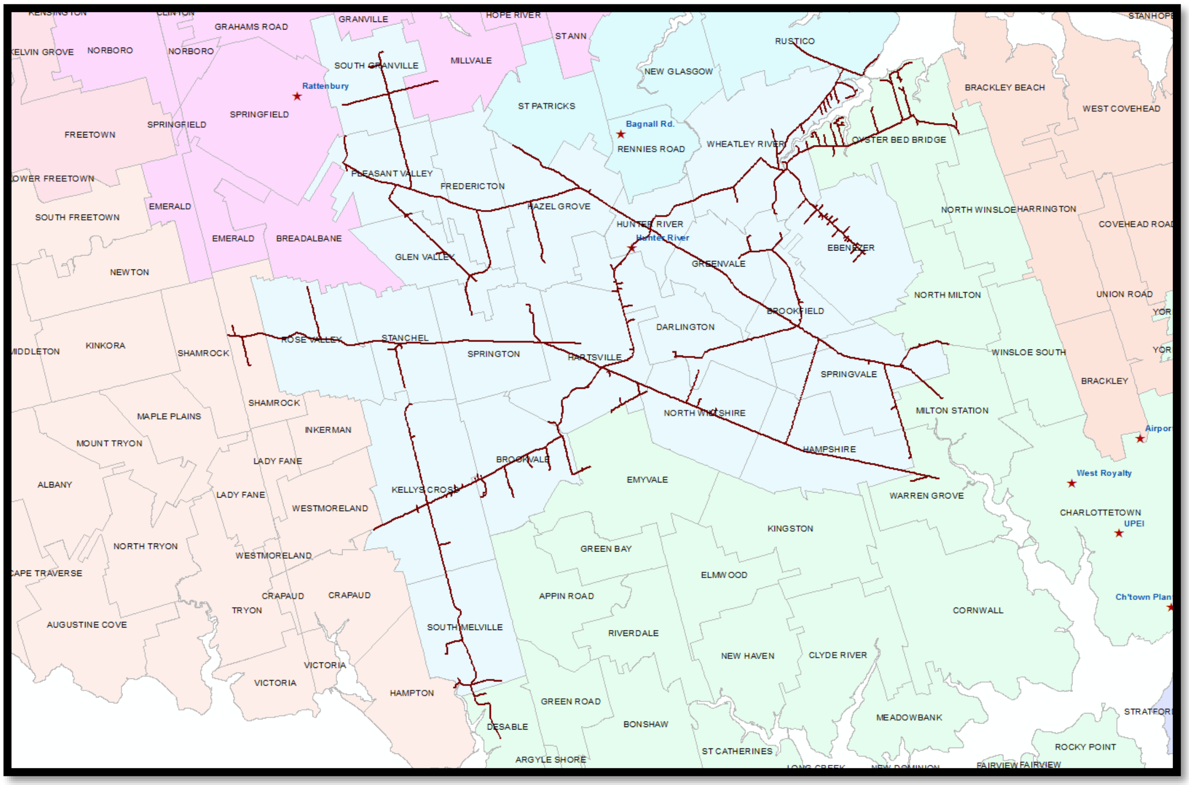

Figure 21: Service Area of Hunter River Substation

The Hunter River Substation (“HR”) is located at 4090 Hopedale Road, Route 13, Hunter River. The substation is normally fed from 69 kV transmission line T-1 out of the West Royalty Substation but it can also be fed from the Sherbrooke Switching Station. The substation has two distribution circuits, Malpeque and Rennies Road. There is one substation transformer (7.5/10 MVA, Co.# 58, 1998 vintage, 69 kV – 12.5 kV), one set of voltage regulators (rated 437 A) and one metering tank. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer and winter peak loads are 4.4 MVA and 6.6 MVA respectively. The winter peak load represents 88 per cent of the ONAN rating and 66 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Bagnall Road in order to reduce the impact of a potential outage.

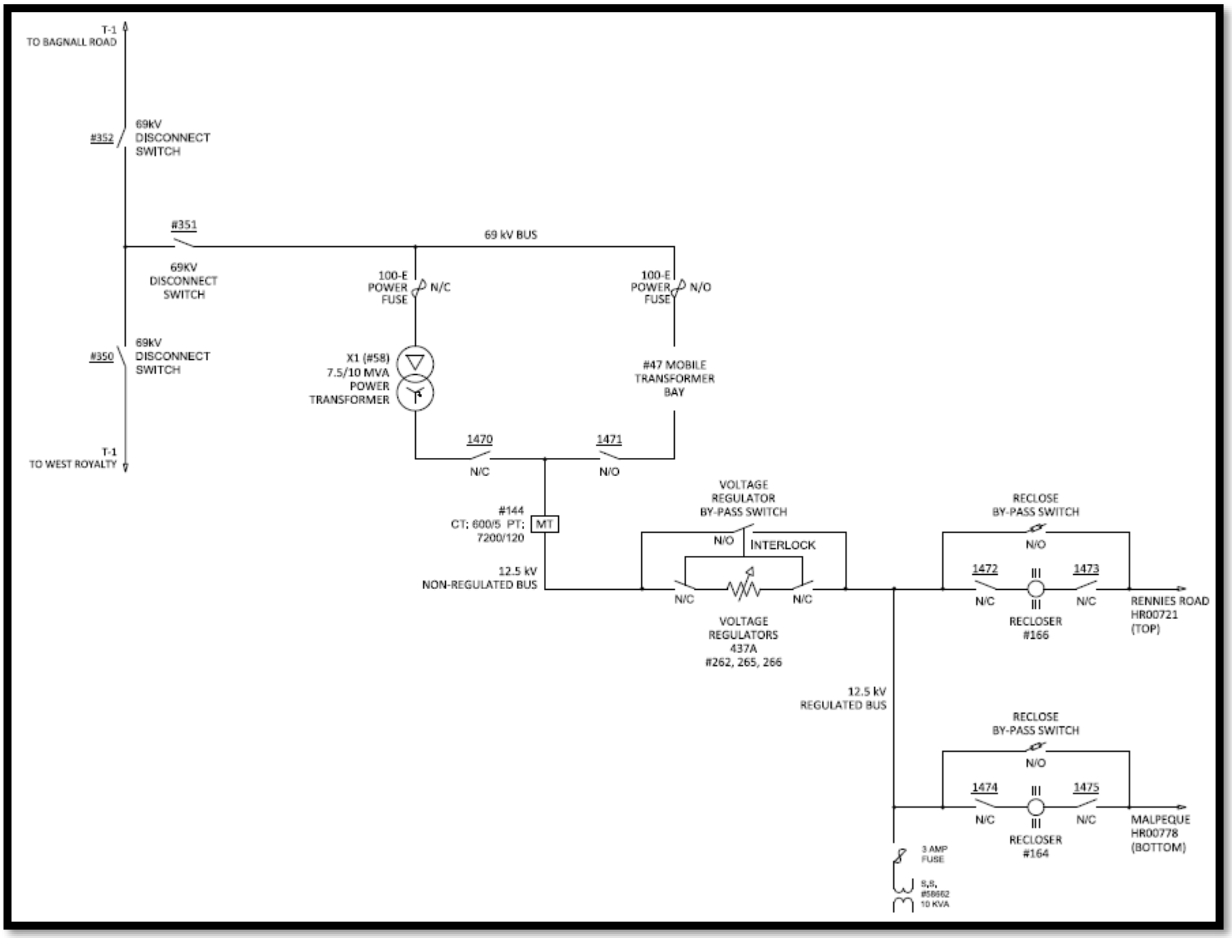

Figure 22: Single-Line Diagram of Hunter River Substation

2.1k Kensington Distribution System

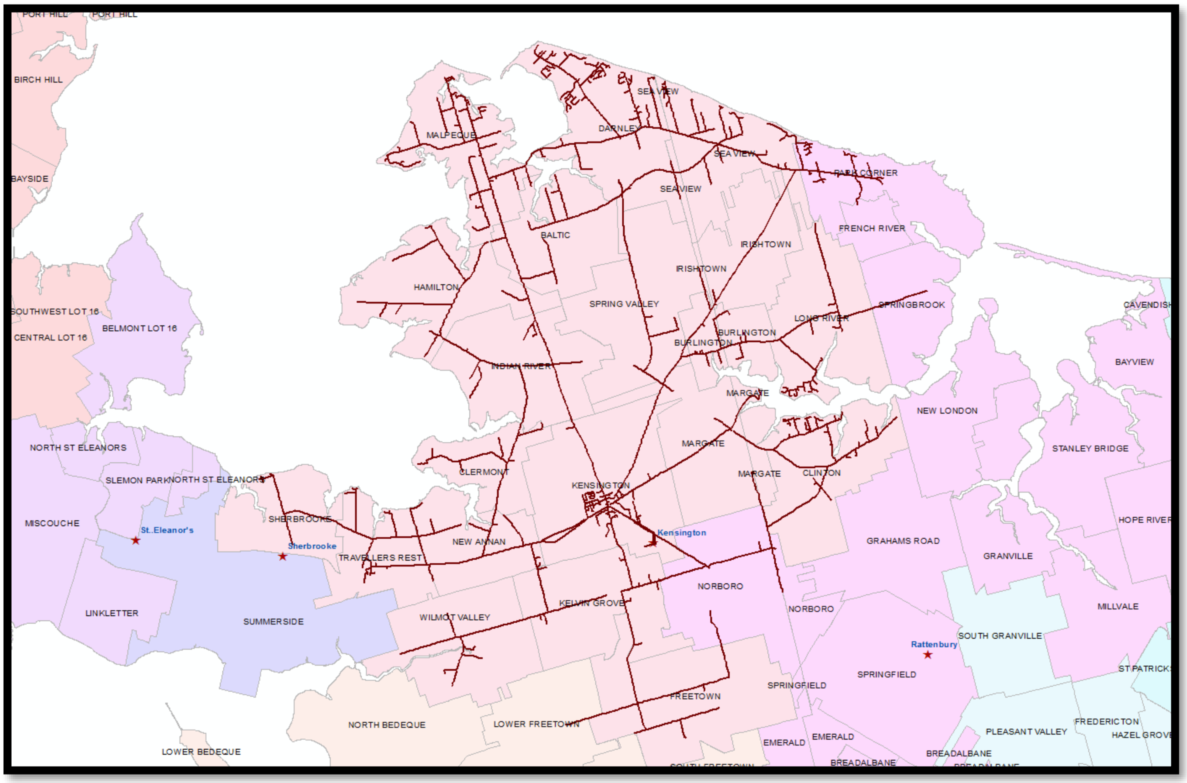

Figure 23: Service Area of Kensington Substation

The Kensington Substation ("KN") is located at 24412 Route #2, Kensington. The substation is fed from 69 kV transmission line T-1 that is normally fed out of Sherbrooke Switching Station but can also be fed out of the West Royalty Substation. The substation has three circuits, Norboro, Irishtown and New Annan. There are two substation transformers ([5/6.7 MVA, Co.# 39, 1977 vintage, 69 kV – 12.5 kV] and [7.5/10 MVA, Co.# 72, 2012 vintage, 69 kV – 12.5 kV]) which are paralleled. The substation has two sets of voltage regulators (both rated 437 A). The substation uses feeder recloser data for metering. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer and winter peak load is 8.8 MVA and 12.3 MVA respectively. The winter peak is 98 per cent of the combined ONAN rating and 74 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Albany and/or Rattenbury in order to reduce the impact of a potential outage.

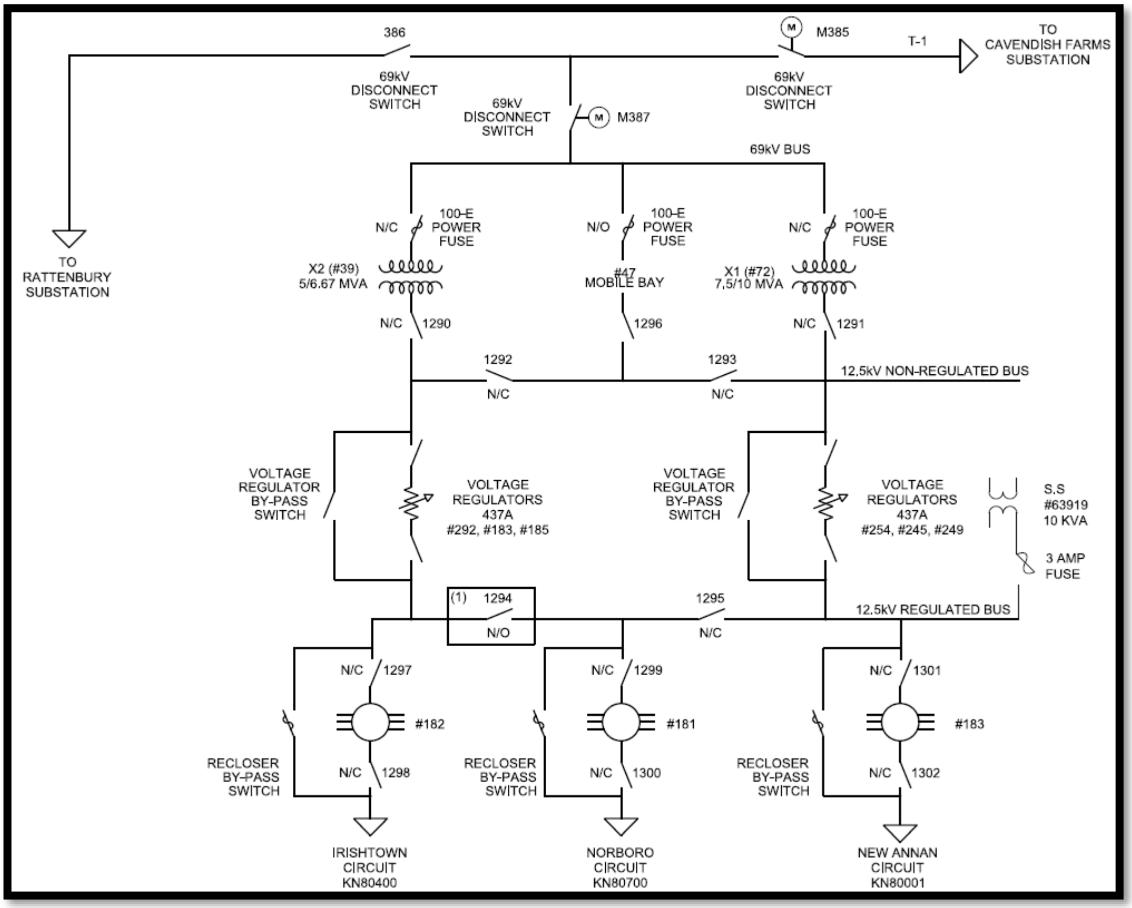

Figure 24: Single-Line Diagram of Kensington Substation

2.1l Mount Albion Distribution System

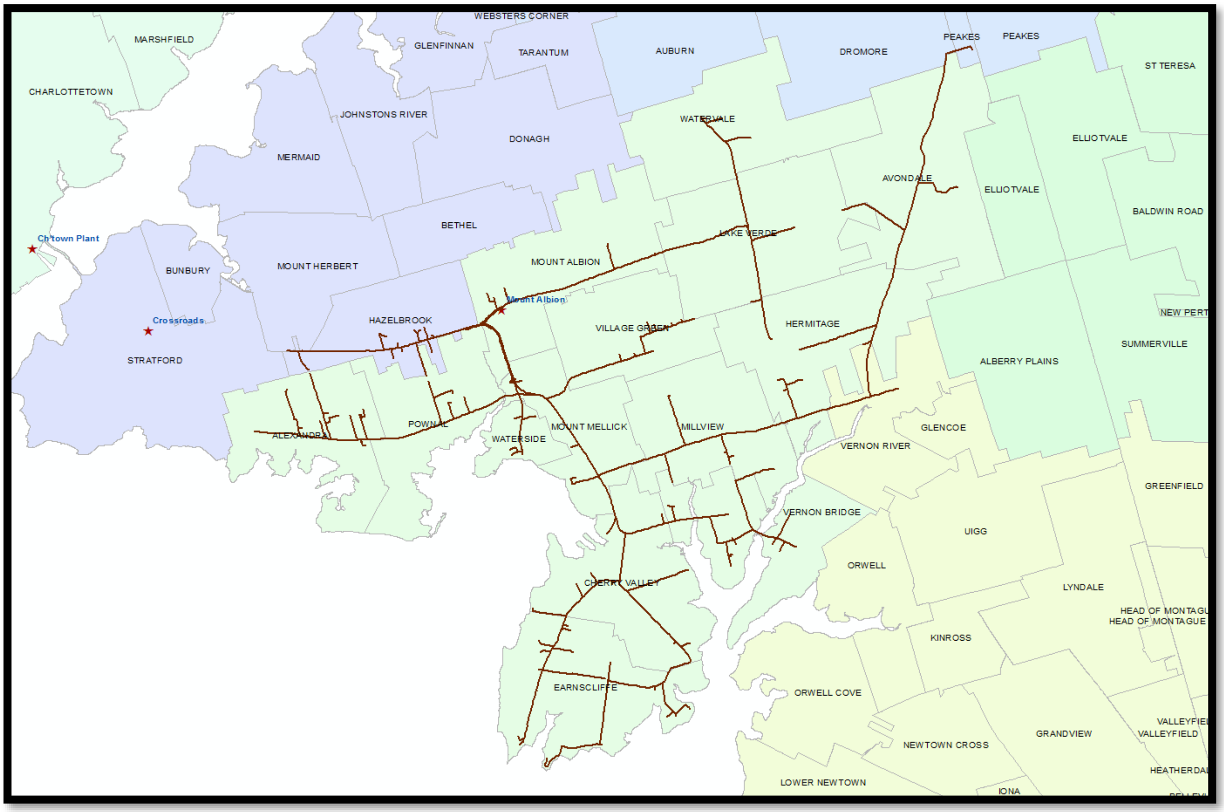

Figure 25: Service Area of Mount Albion Substation

The Mount Albion Substation ("MA") is located at 124 48 Road, Route 5, Mount Albion. The substation is fed from 69 kV transmission line T-2 fed out of the Charlottetown Plant and Lorne Valley Switching Station. The substation has three distribution circuits, Hazelbrook, Alexandra and Vernon River. A transfer bus is present, which allows for any recloser to be taken out of service for maintenance, without causing any customer outages. There is one substation transformer (7.5/10 MVA, Co.# 81, 2018 vintage, 69 kV – 12.5 kV) in the substation. The substation has an on load tap changer for voltage regulation and uses bus PT's and transformers CT's for metering. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 79. The summer and winter peak load is 2.5 MVA and 3.6 MVA respectively. The winter peak is 48 per cent of the ONAN rating and 36 per cent of ONAF rating. More load will be transferred from Crossroad Substation to Mount Albion Substation in the coming years. If needed, and depending on load condition, this substation can be paralleled with Crossroads and/or Georgetown in order to reduce the impact of a potential outage.

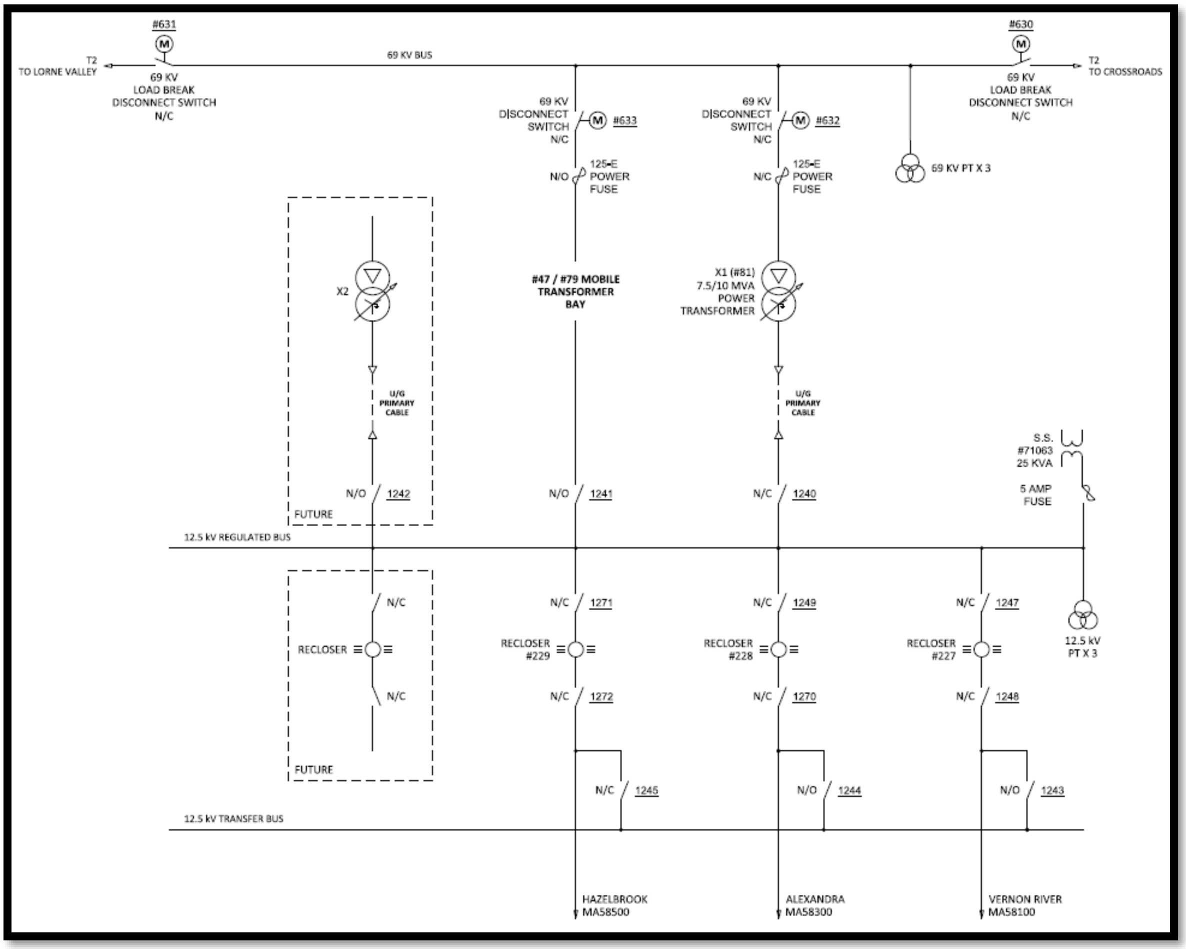

Figure 26: Single-Line Diagram of Mount Albion Substation

2.1m O'Leary Distribution System

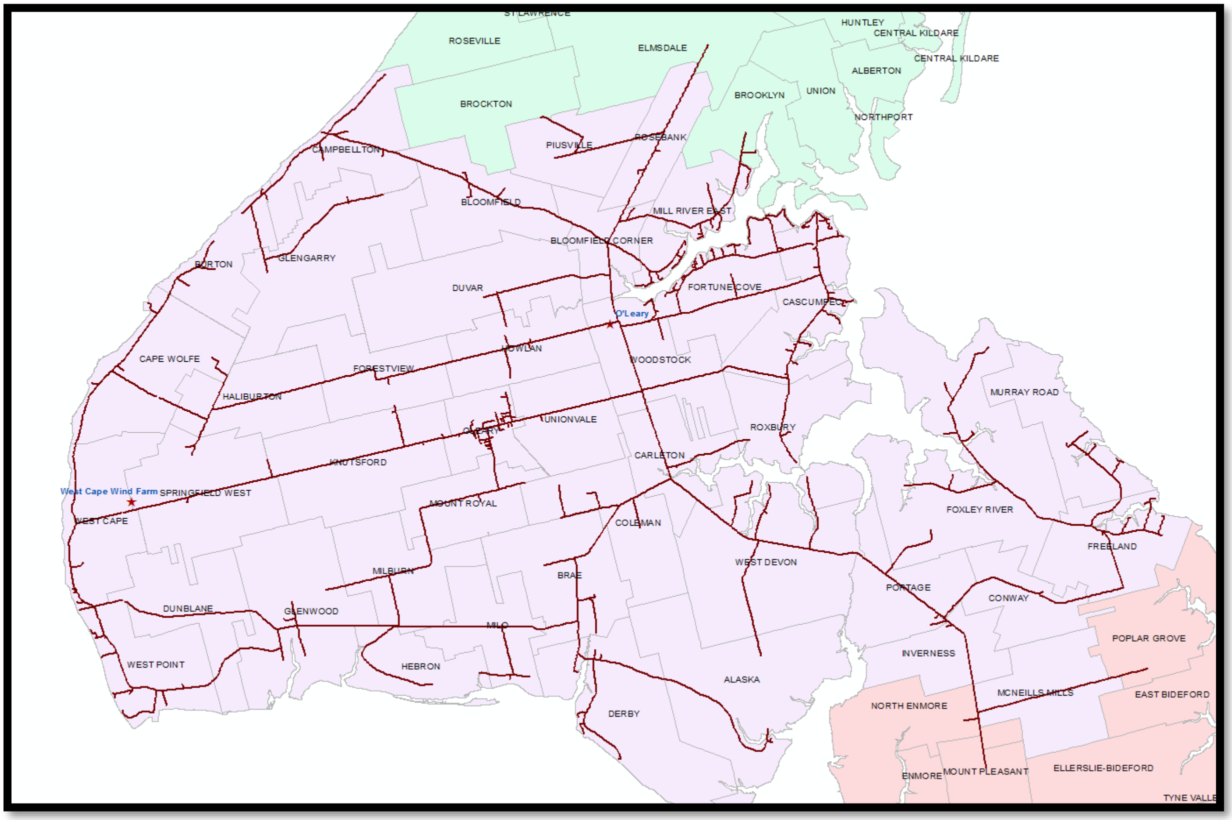

Figure 27: Service Area of O'Leary Substation

The O'Leary Substation ("OL") is located at 63 Howlan Road, Route 143, Woodstock. The substation is fed from the 69 kV transmission line T-21 out of Wellington. The substation has two distribution circuits O'Leary and Howlan Road. There are two substation transformers (7.5/10 MVA each: [Co.# 57, 1995 vintage, 69 kV – 25 kV/12.5 kV] and [Co.# 65, 2006 vintage, 69 kV – 12.5 kV]) which are paralleled. The substation has two sets of voltage regulators (each rated 437 A) and one metering tank for transformer #57. Transformer #65 is metered according to transformer CT's and the metering tank PT's. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer peak load is 7.4 MVA while the winter peak load is 10.1 MVA. The winter peak represents 67 per cent of the combined ONAN rating and 51 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Wellington in order to reduce the impact of a potential outage.

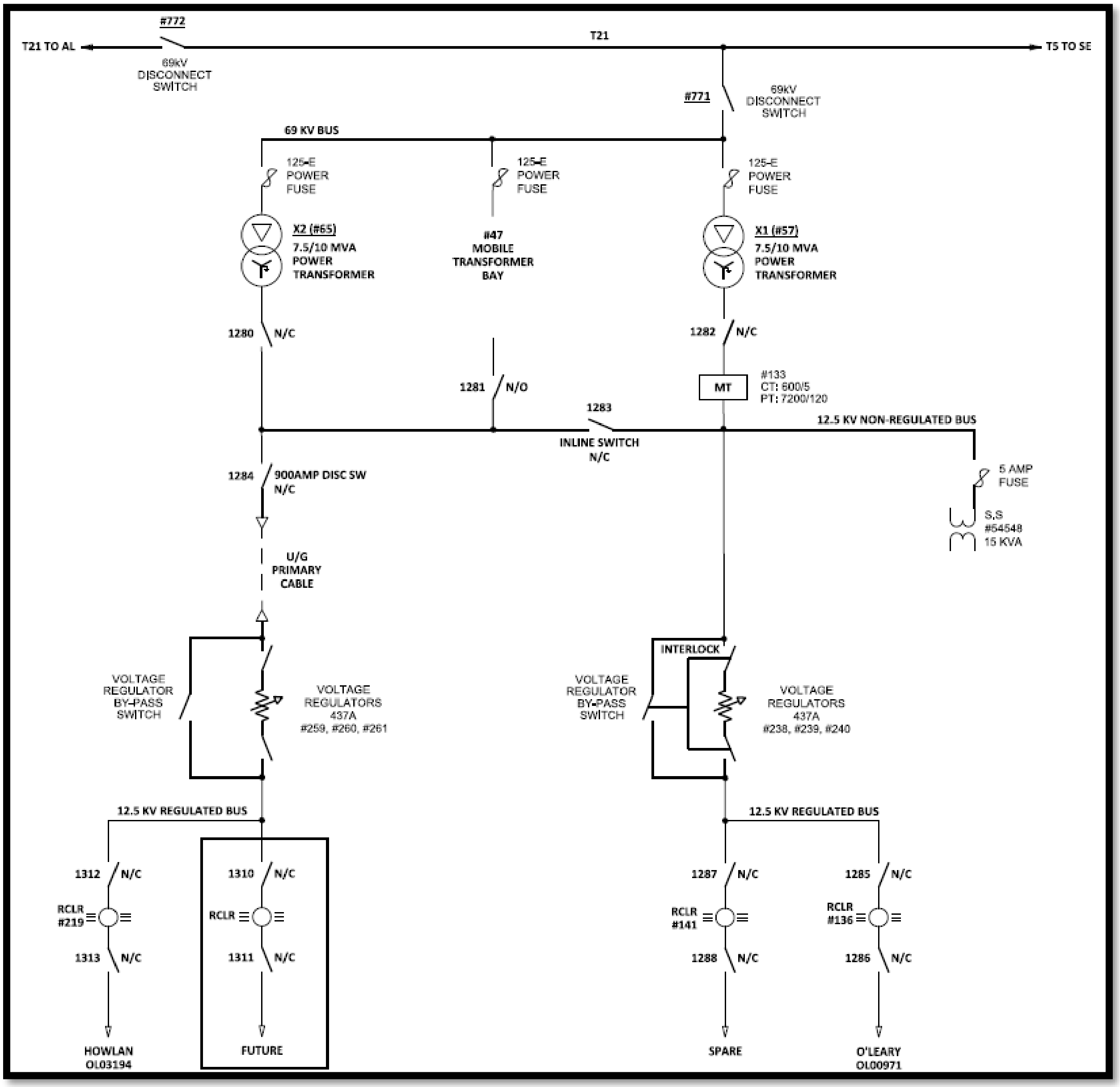

Figure 28: Single-Line Diagram of O'Leary Substation

2.1n Rattenbury Distribution System

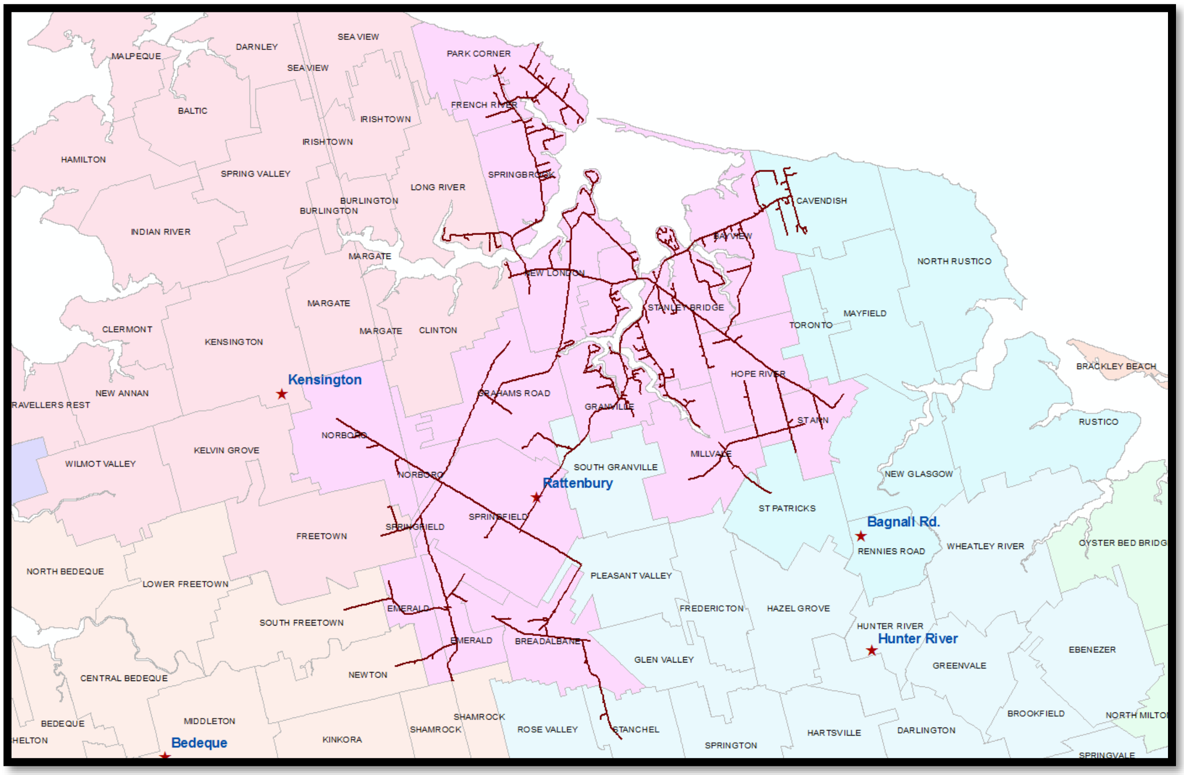

Figure 29: Service Area of Rattenbury Substation

The Rattenbury Substation ("RT") is located at 247 Rattenbury Road, Route 254, Springfield. The substation is normally fed from 69 kV transmission line T-1 out of Sherbrooke Switching Station but it can also be fed out of the West Royalty Substation. The substation has two distribution circuits, Stanley Bridge and Summerfield. The substation has set of voltage regulators (rated 328 A) and one metering tank. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. There is one substation transformer (5/6.7 MVA, Co.# 36, 1975 vintage, 69 kV – 12.5 kV) that has a summer peak load of 6.2 MVA and a winter peak load of 5.0 MVA. The summer peak load represents 124 per cent of the ONAN rating and 93 per cent of the ONAF rating. Since July 2020, the majority of Cavendish is being fed from the Bagnall Road Substation; however, to maintain reliability in the area, capacity should be available from both Bagnall Road and Rattenbury Substations. The electrical demand on the substation has increased by 39 per cent over a 10 year period and under current loading conditions, it is forecasted to surpass 6.7 MVA in 2021. A new 7.5/10 MVA transformer is planned for Rattenbury in 2021. If needed, and depending on load condition, this substation can be paralleled with Bagnall Road and/or Kensington in order to reduce the impact of a potential outage.

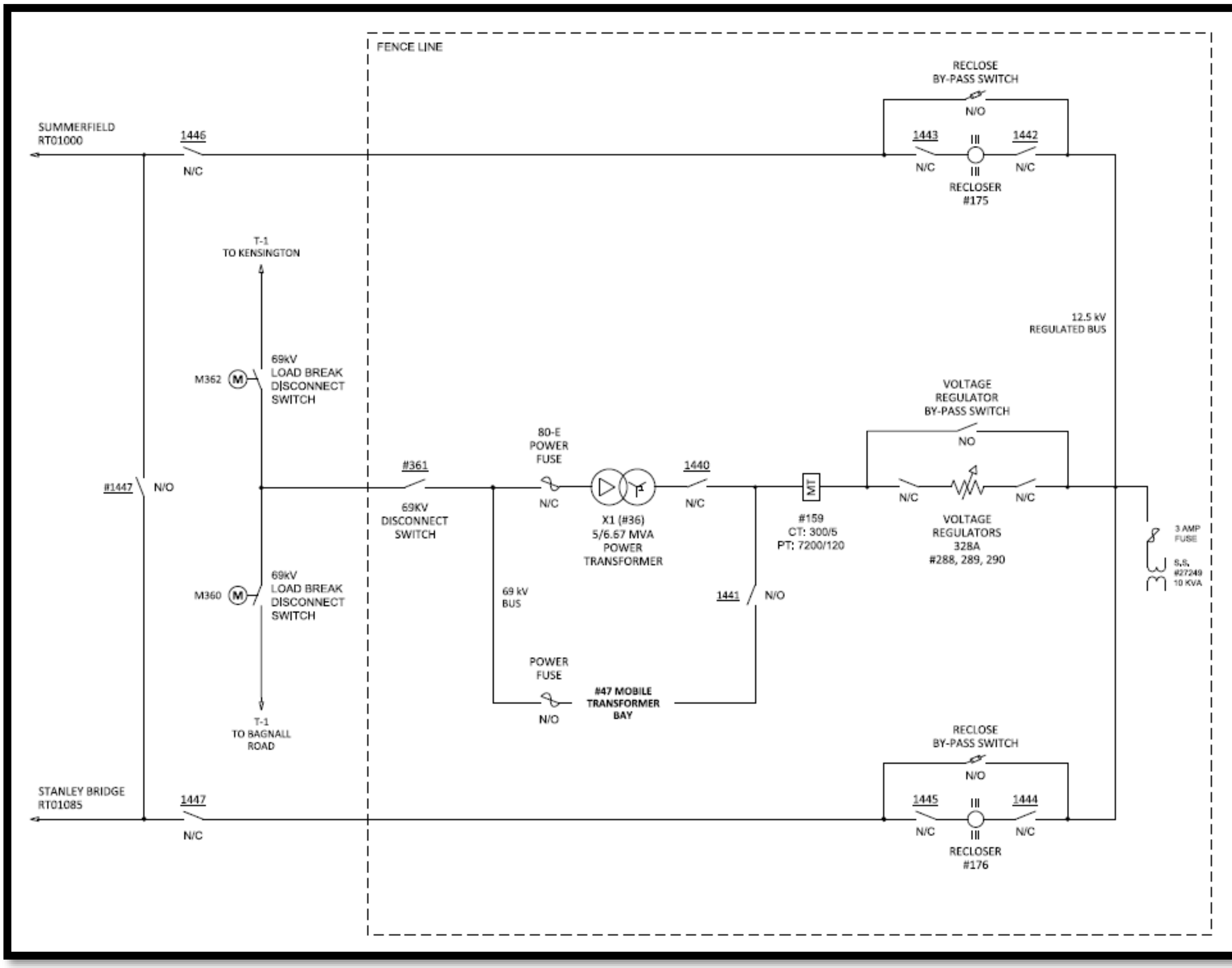

Figure 30: Single-Line Diagram of Rattenbury Substation

2.1o Scotchfort Distribution System

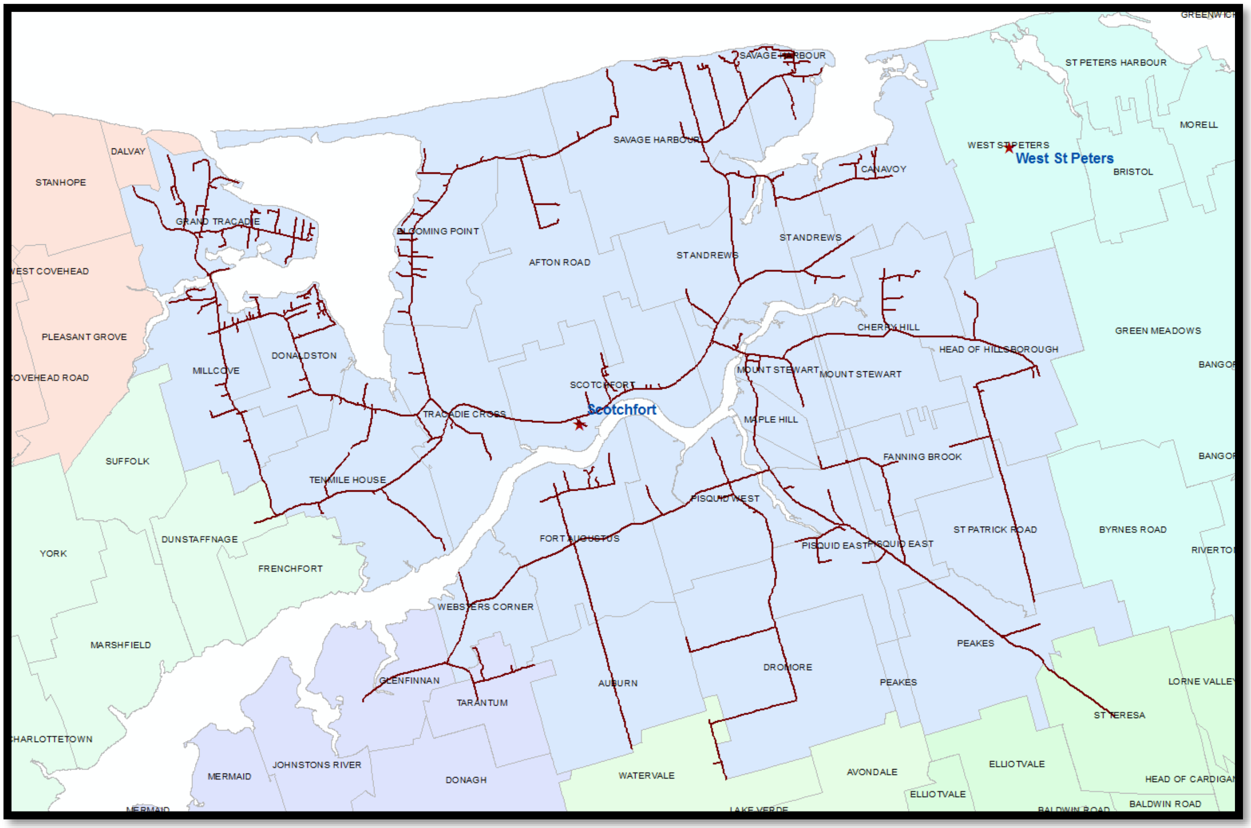

Figure 31: Service Area of Scotchfort Substation

The Scotchfort Substation ("SF") is located at 40 McBride Road in Scotchfort. The substation is fed from 69 kV transmission line T-4 out of the Lorne Valley Switching Station. The substation has two distribution circuits, Mount Stewart and Bedford. There is one substation transformer (7.5/10 MVA, Co.# 70, 2014 vintage, 69 kV – 12.5 kV). The substation has one set of voltage regulators (rated 437 A) and one metering tank. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer and winter peak load is 3.6 MVA and 5.4 MVA respectively. The winter peak load represents 72 per cent of the ONAN rating and 54 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with West St. Peters and/or UPEI in order to reduce the impact of a potential outage.

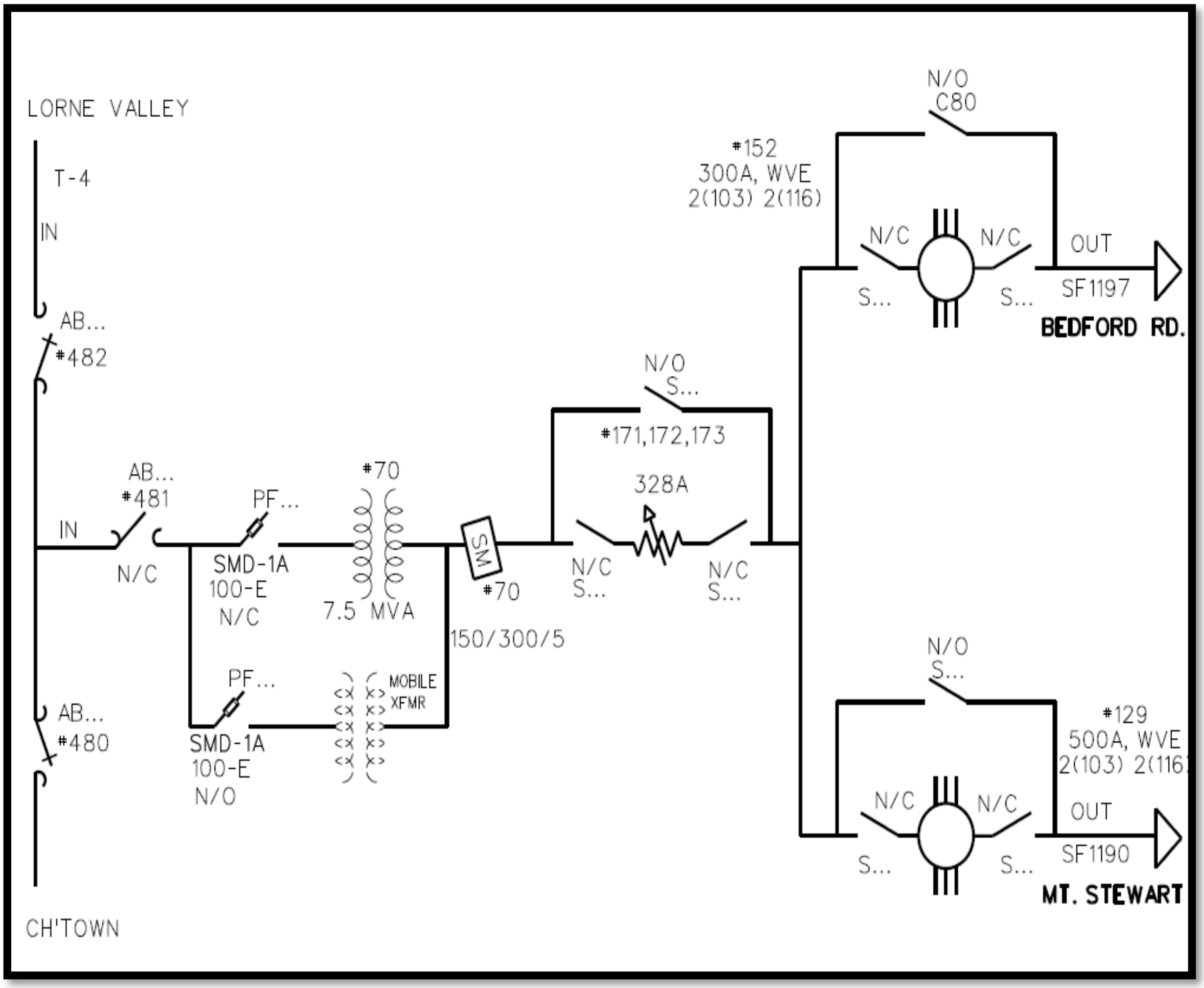

Figure 32: Single-Line Diagram of Scotchfort Substation

2.1p Souris Distribution System

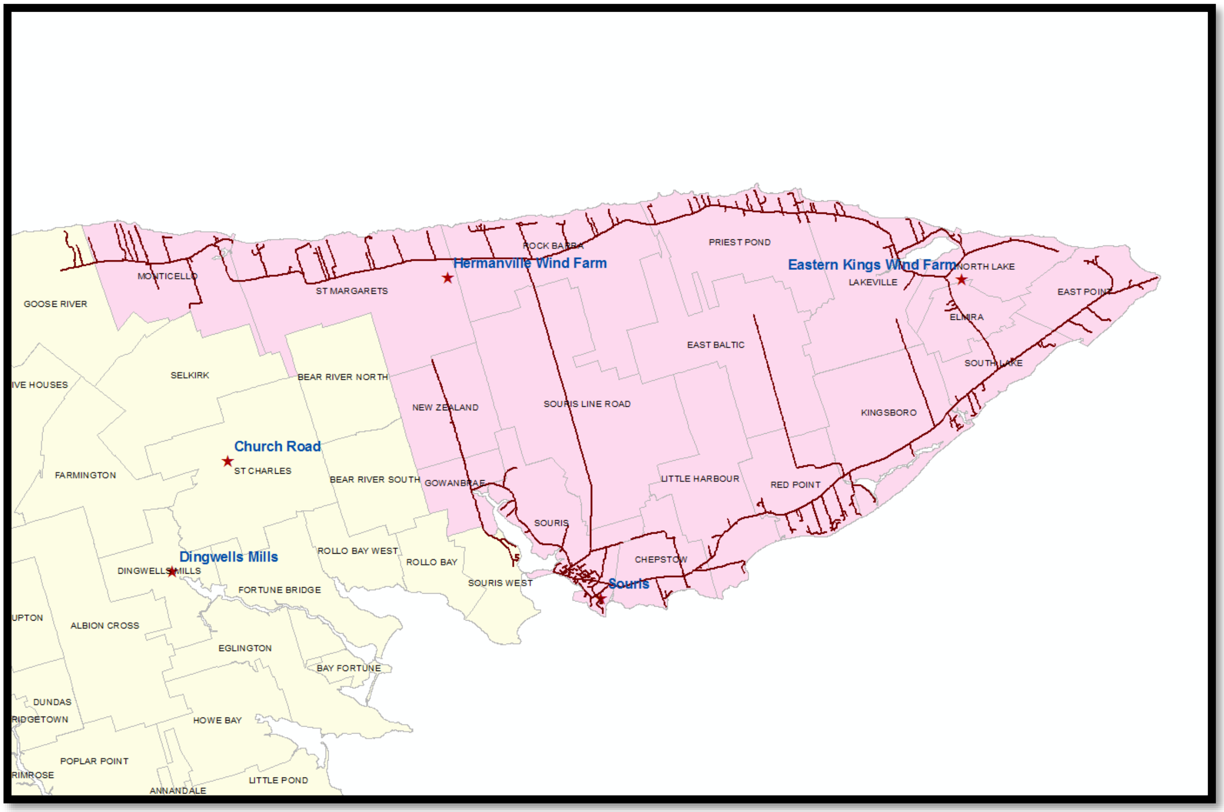

Figure 33: Service Area of Souris Substation

The Souris Substation ("SO") is located at 9 Hope Street in Souris. The substation is fed from 69 kV transmission line T-8 out of the Church Road and Lorne Valley Switching Stations. The substation has three distribution circuits, Town of Souris, Souris Food Industrial Park and East Point. There are two substation transformers ([4.0/5.97 MVA, Co.# 23, 1967 vintage, 66 kV/33 kV – 25 kV/12.5 kV] and [4.0/6.0 MVA, Co.# 28, 1971 vintage, 66 kV/33 kV – 25 kV/12.5 kV]) that are paralleled. The substation has one set of voltage regulators (rated 437 A) and two metering tanks. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer and winter peak load is 6.4 MVA and 7.5 MVA respectively. The winter peak represents 94 per cent of the combined ONAN rating and 63 per cent of the combined ONAF rating.

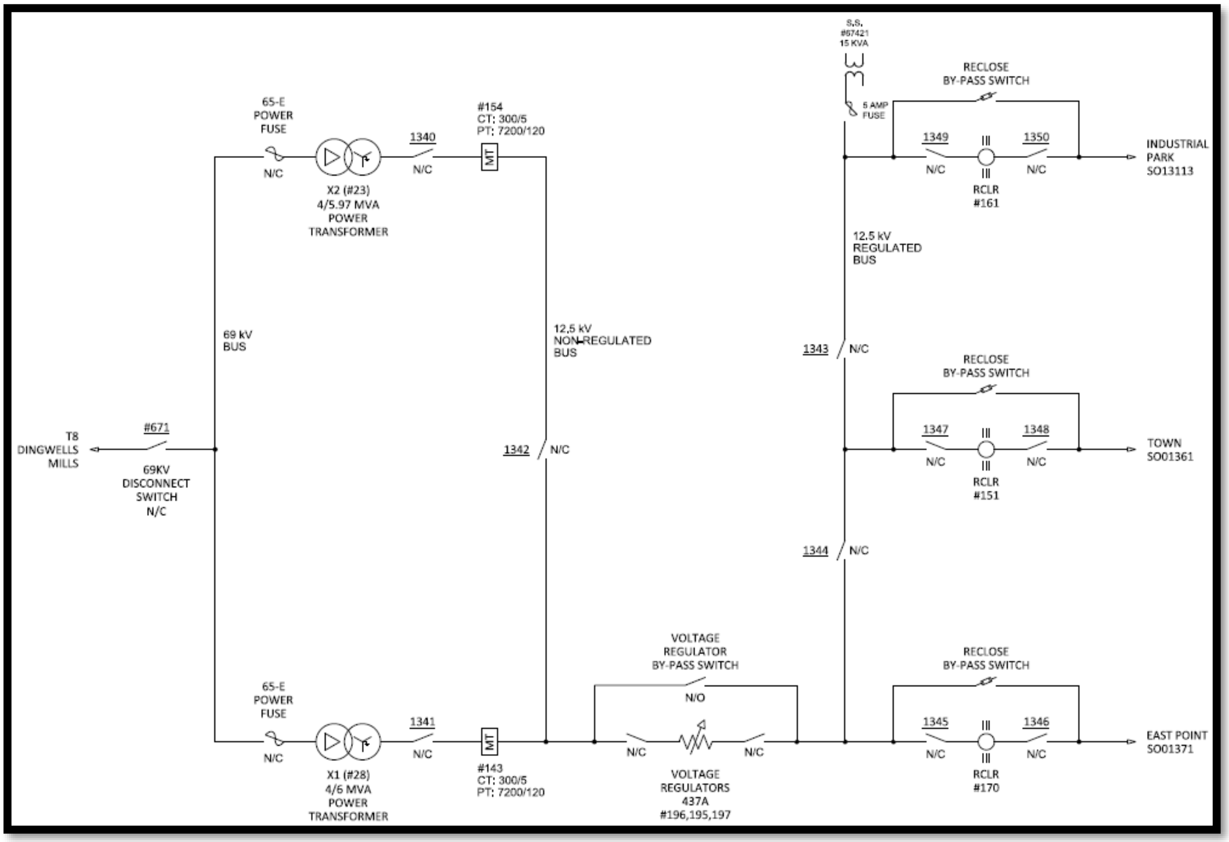

Figure 34: Single-Line Diagram of Souris Substation

2.1q St. Eleanors Distribution System

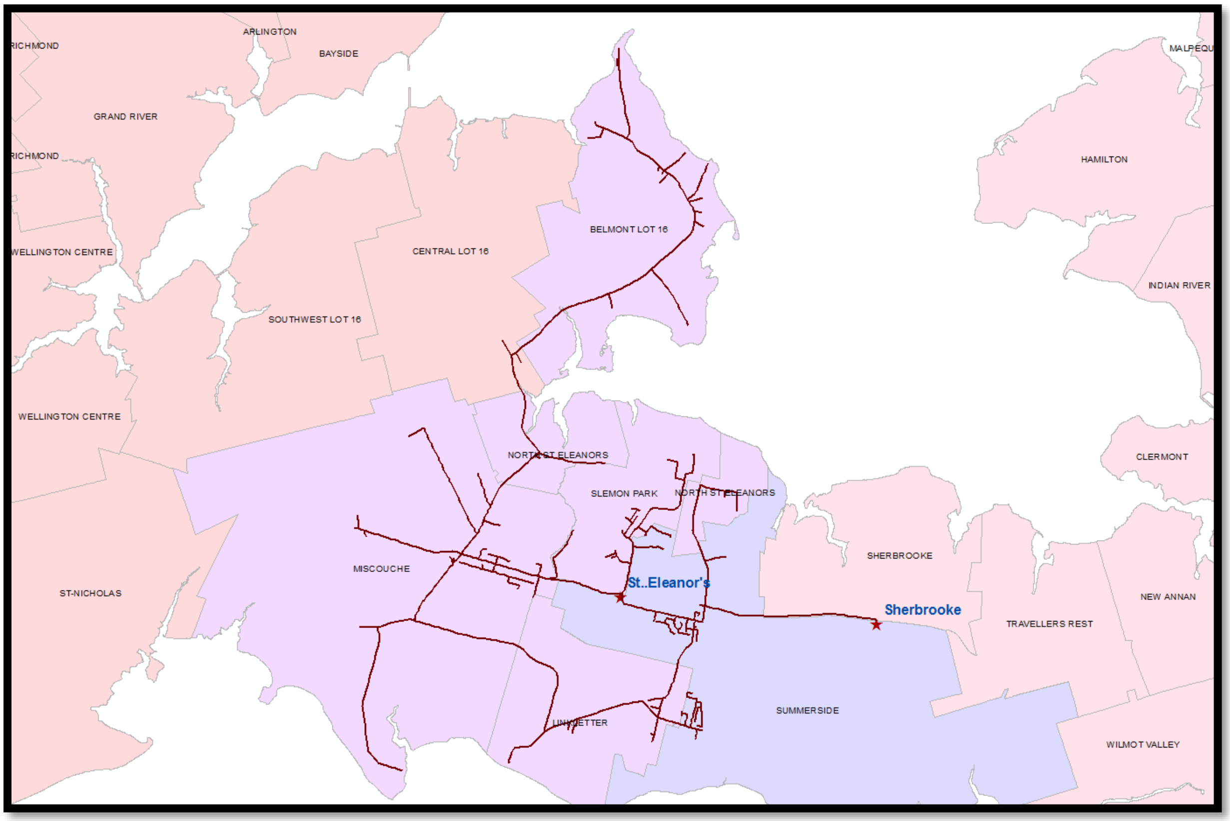

Figure 35: Service Area of St. Eleanors Substation

The St. Eleanors Substation ("SE") is located at 230 West Drive in St. Eleanors. The substation is fed from 69 kV transmission line T-5 out of the Sherbrooke Switching Station. The substation has three distribution circuits, Miscouche, Slemon Park and Sherbrooke. The Sherbrooke circuit feeds the Company's Sherbrooke Service Centre. There are two substation transformers (5/6.7 MVA each: [Co.# 37, 1975 vintage, 69 kV – 12.5 kV] and [Co.# 44, 1978 vintage, 69 kV – 12.5 kV]) that are paralleled. The substation has one set of voltage regulators and one metering tank. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 47. The summer peak load is 5.3 MVA while the winter peak load is 6.4 MVA. The winter peak represents 64 per cent of the combined ONAN rating and 48 per cent of the combined ONAF rating.

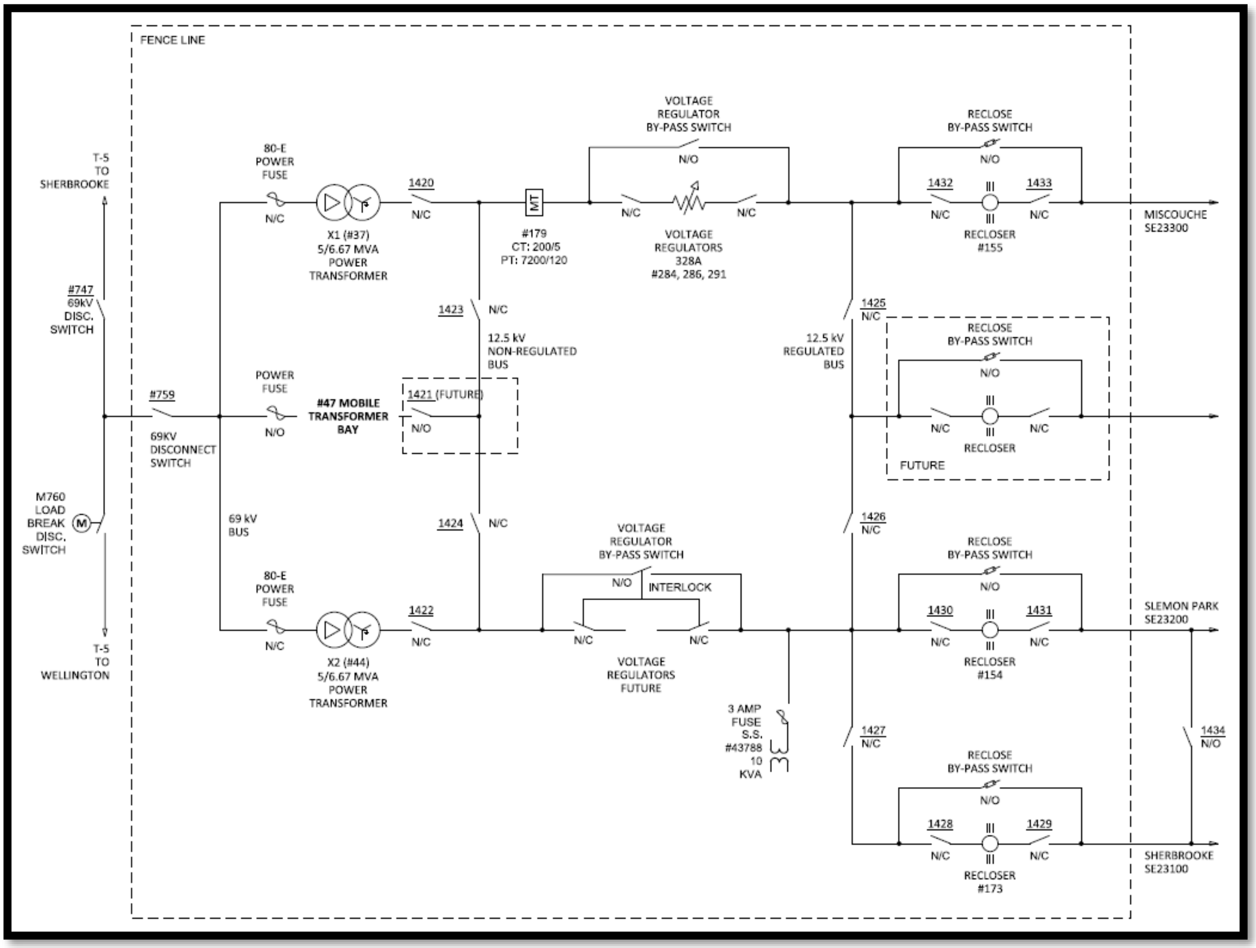

Figure 36: Single-Line Diagram of St. Eleanors Substation

2.1r UPEI Distribution System

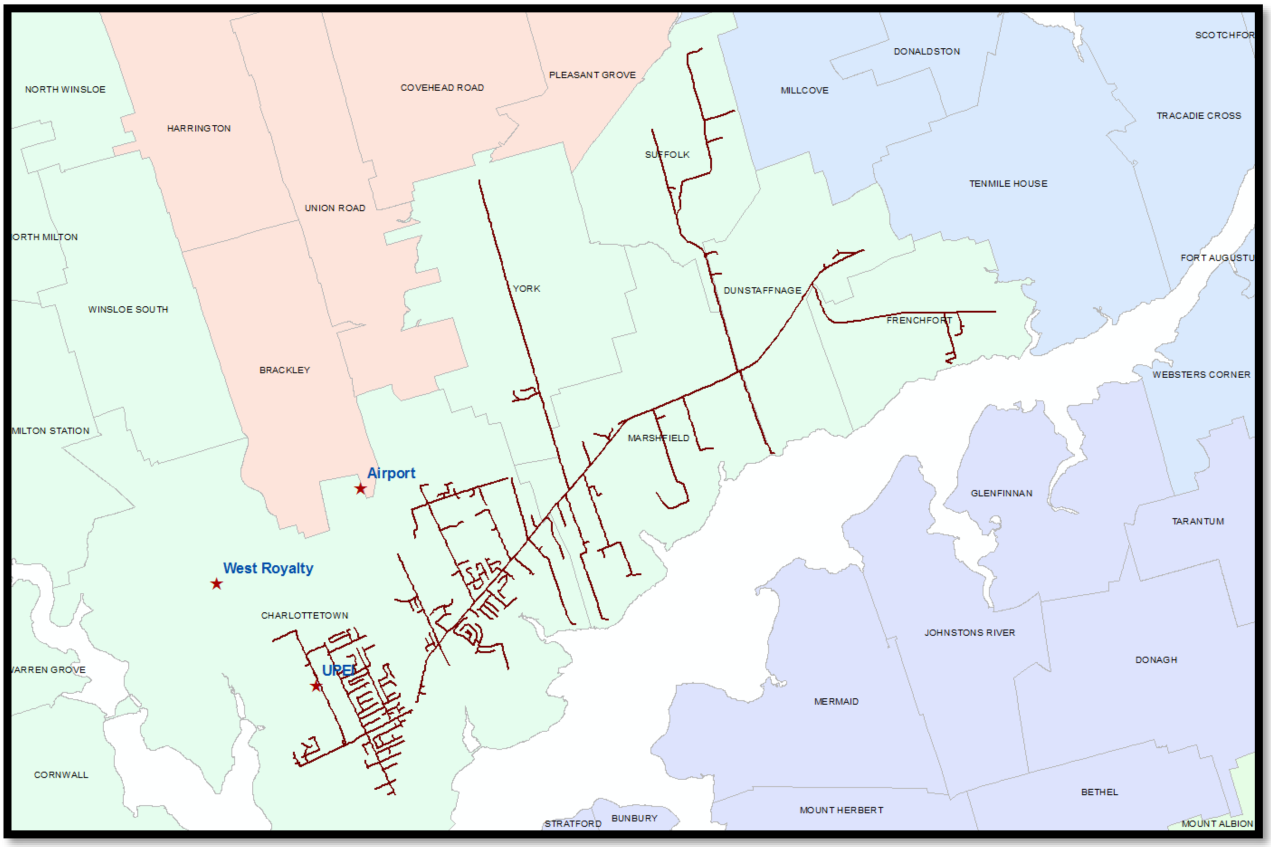

Figure 37: Service Area of UPEI Substation

The UPEI Substation ("UP") is located on the University of PEI ("UPEI") campus in Charlottetown. The substation is fed from 69 kV transmission line T-13 out of the West Royalty and Charlottetown Plant Substations. The substation has four distribution circuits, Pine Drive, Charlottetown Mall, Belvedere and UPEI. There is one substation transformer (15/20 MVA, Co.# 74, 2014 vintage, 69 kV – 13.8 kV) providing energy at 13.8 kV. The substation has an on load tap changer for voltage regulation and uses bus PT's and transformer CT's for metering. The substation is not equipped with a mobile transformer bay. The summer peak load is 12.8 MVA while the winter peak load is 14.7 MVA. The winter peak represents 98 per cent of the ONAN rating and 74 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Charlottetown Plant and/or West Royalty in order to reduce the impact of a potential outage.

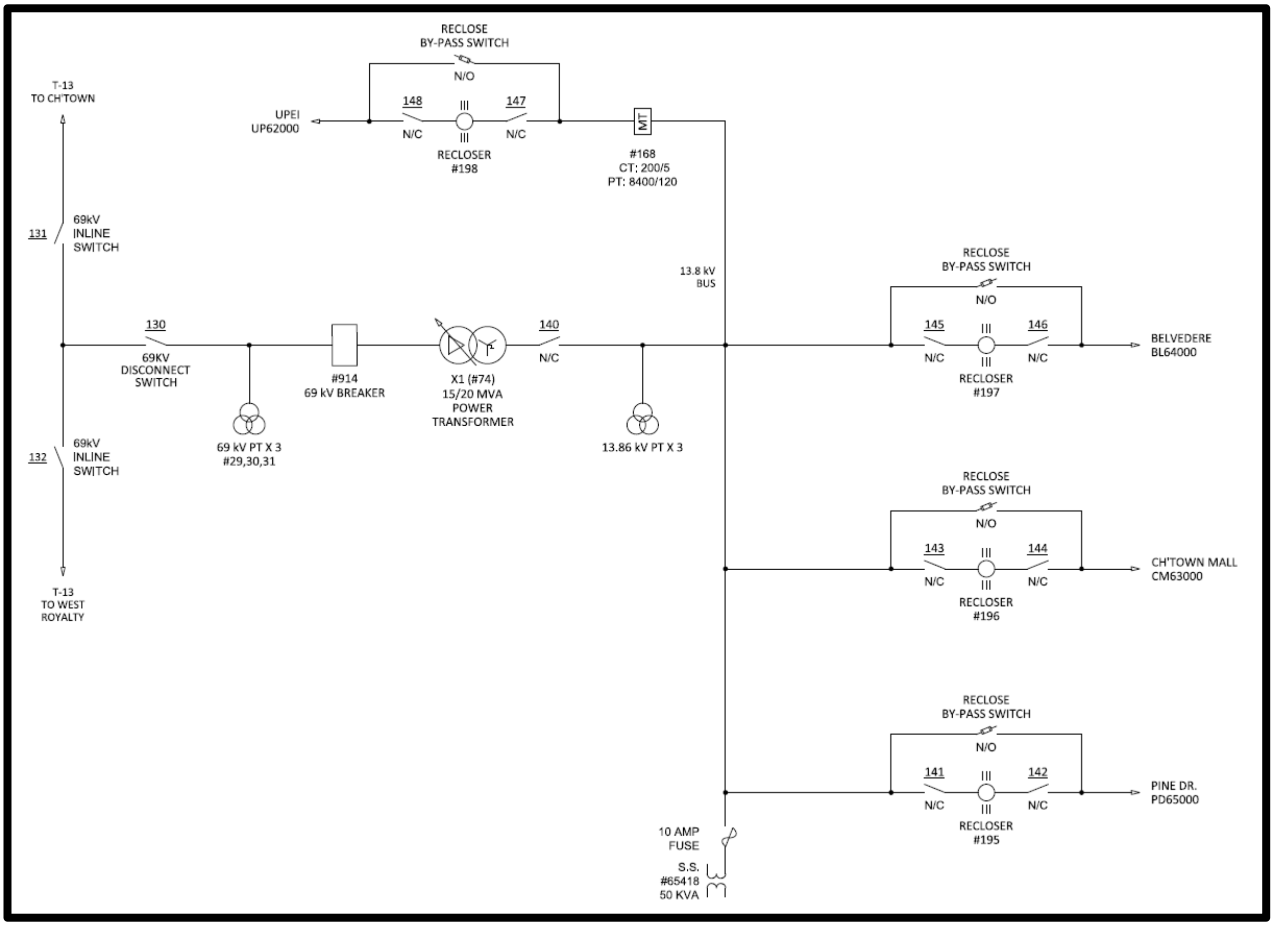

Figure 38: Single-Line Diagram of UPEI Substation

2.1s Victoria Cross Distribution System

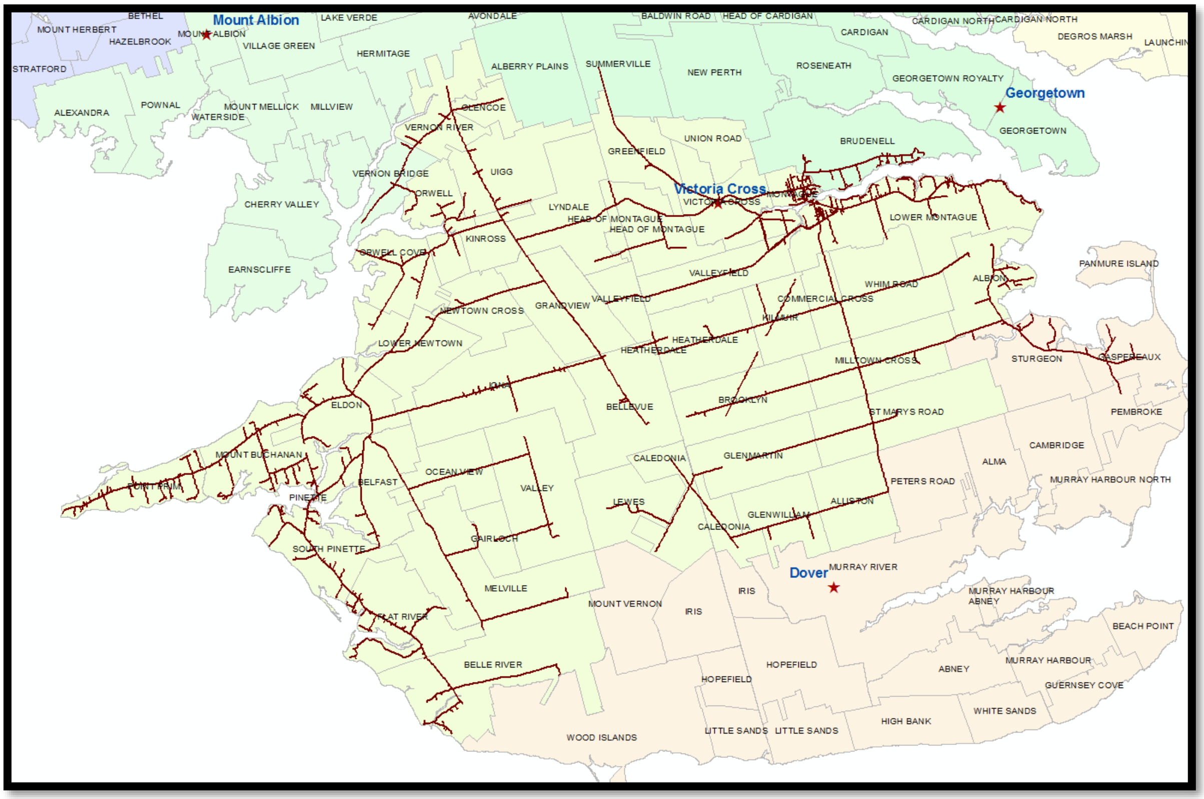

Figure 39: Service Area of Victoria Cross Substation

The Victoria Cross Substation ("VC") is located at 5400 Sparrows Road - Route 320 in Montague. The substation is fed from 69 kV transmission line T-10 out of the Lorne Valley Switching Station. Victoria Cross has two distribution voltages 12.5 kV and 25 kV. The substation has two 25 kV distribution circuits, Commercial Road and Eldon-Belfast, and two 12.5 kV distribution circuits, Montague and Valleyfield. There are two substation transformers (7.5/10 MVA each: [Co.# 52, 1981 vintage, 69 kV – 25 kV] and [Co.# 68, 2010 vintage, 69 kV – 12.5 kV]) that are not paralleled. The substation has two voltage regulators (one rated 300 A on the 25 kV side and one rated 437 A on the 12.5 kV side) and two metering tanks. The Victoria Cross Substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 47. The summer and winter peak load on the 69 kV - 12.5 kV transformer is 5.1 MVA and 6.2 MVA respectively. The winter peak represents 83 per cent of the ONAN rating and 62 per cent of the ONAF rating. The summer and winter peak load on the 69 kV - 25 kV transformer is 4.7 MVA and 6.5 MVA respectively. The winter peak represents 87 per cent of the ONAN rating and 65 per cent of the ONAF rating. If needed, and depending on load condition, the substation's 12.5 kV customers can be paralleled with Georgetown in order to reduce the impact of a potential outage.

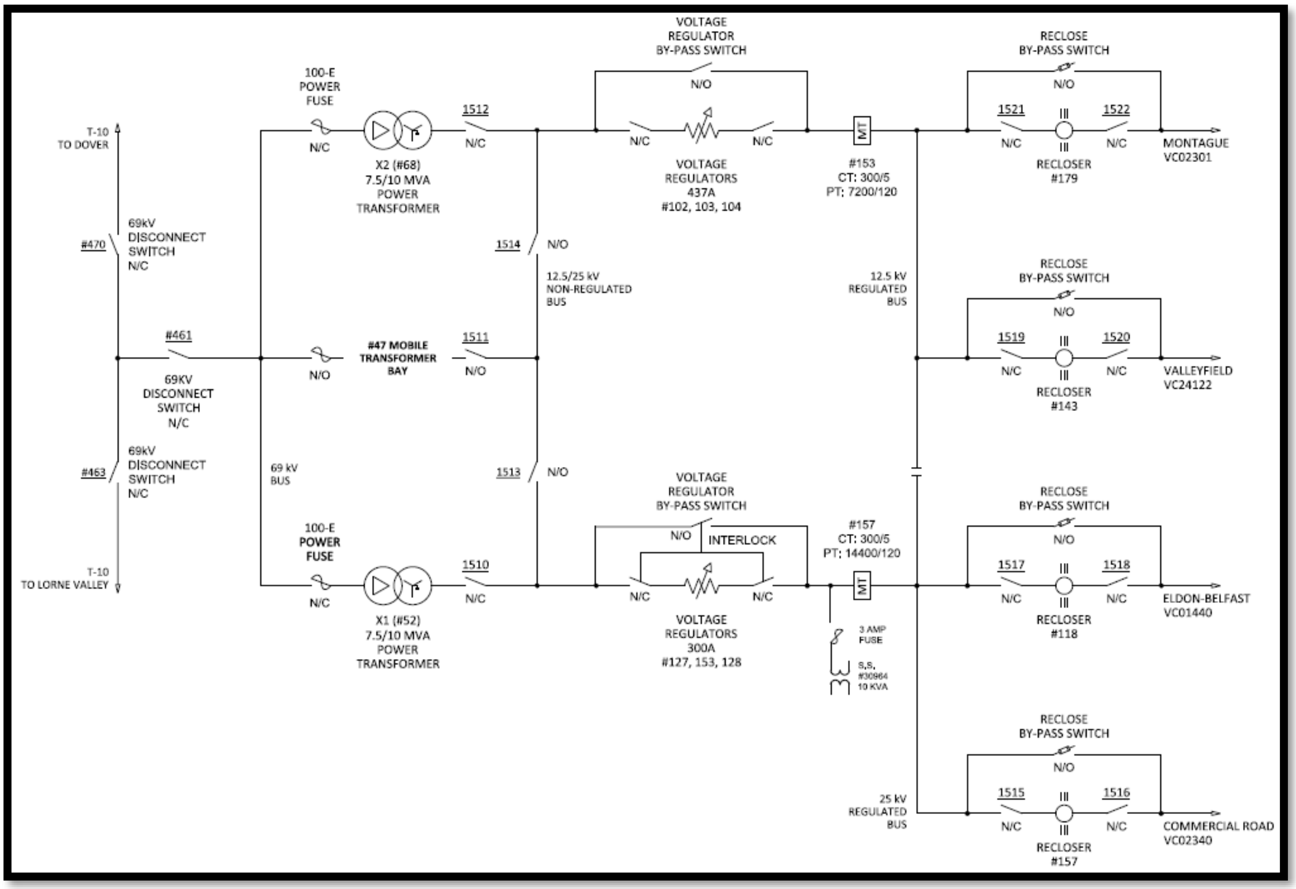

Figure 40: Single-Line Diagram of Victoria Cross Substation

2.1t Wellington Distribution System

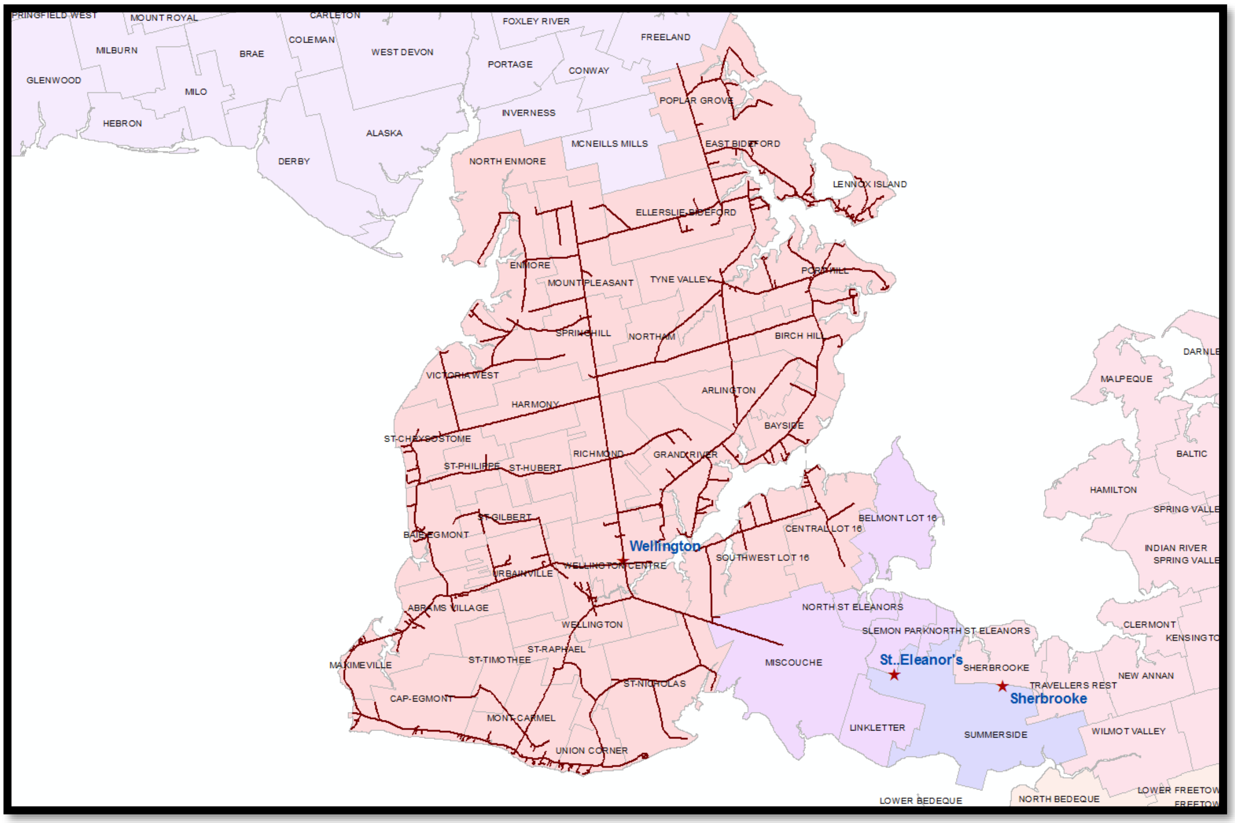

Figure 41: Service Area of Wellington Substation

This Wellington Substation ("WL") is located at 30567 Western Road, Route 2 in Wellington Centre. The substation is fed from 69 kV transmission line T-5 out of the Sherbrooke Switching Station. Transmission line T-21 originates from the Wellington Substation to feed further west. The substation has three circuits, St. Nicholas, Wellington West and Abrams Village, and was built with a provision for a fourth feeder. There is one substation transformer (7.5/10 MVA, Co.# 80, 2017 vintage, 69 kV – 12.5 kV). The substation has an on load tap changer for voltage regulation and uses bus PT's and transformer CT's for metering. The substation is equipped with a mobile transformer bay and can accept mobile transformer Co.# 79. The summer and winter peak load is 6.7 MVA and 8.9 MVA respectively. The winter peak is 119 per cent of the ONAN rating and 89 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with O'Leary in order to reduce the impact of a potential outage.

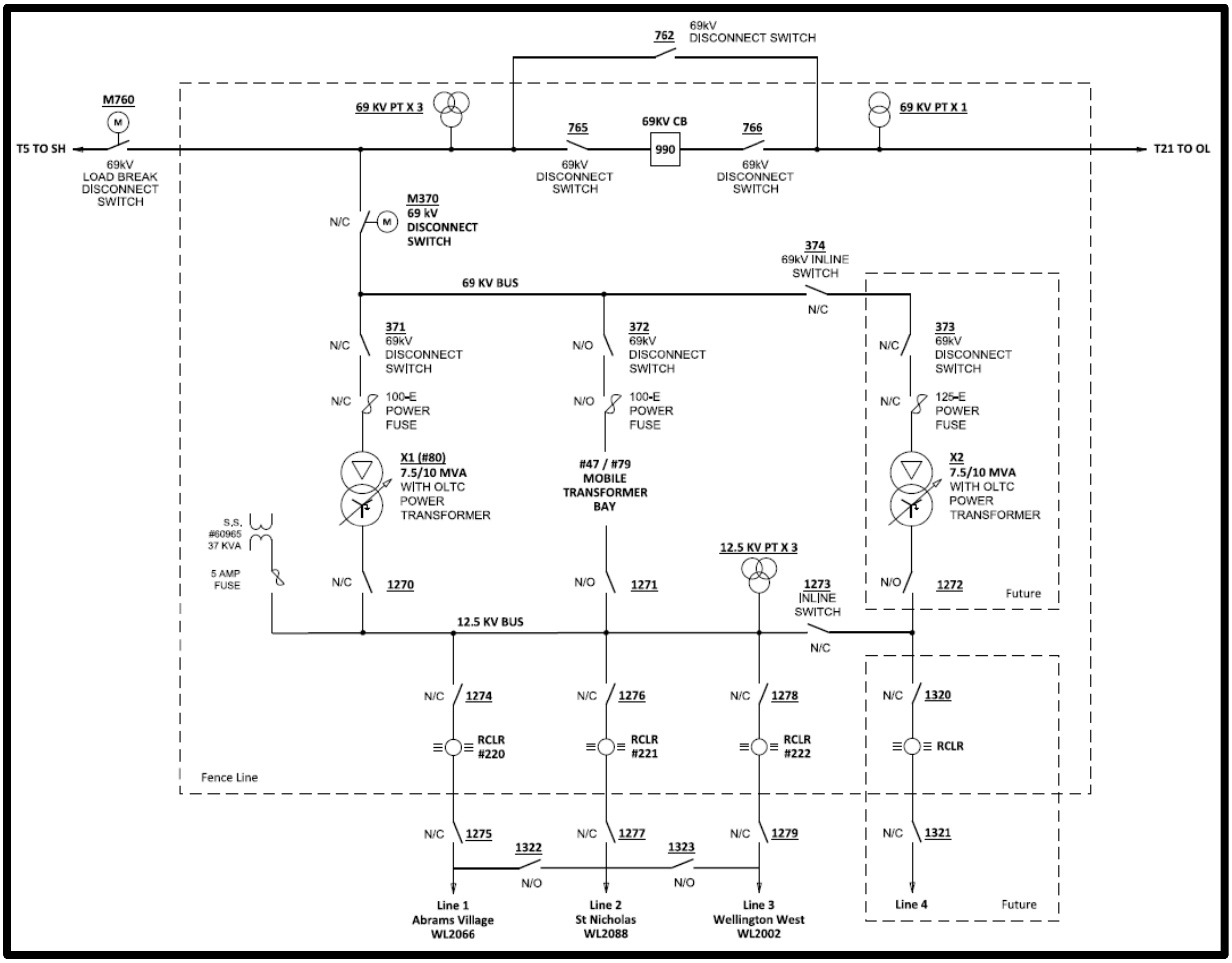

Figure 42: Single-Line Diagram of Wellington Substation

2.1u West Royalty City Distribution System

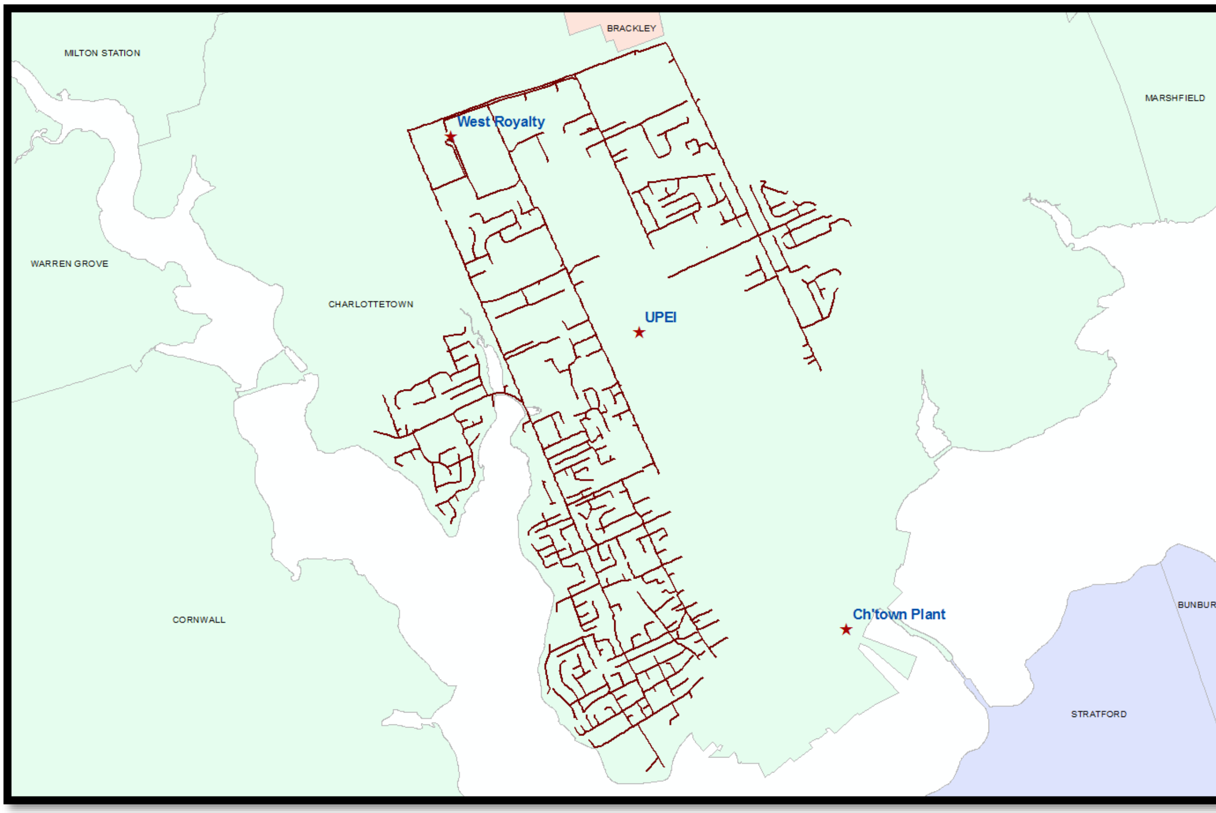

Figure 43: Service Area of West Royalty Substation

The West Royalty Substation ("WR") is located at 30 Sherwood Road in Charlottetown. The substation is fed from a 138 kV bus (supplied by Y-109/Y-111/Y-104) and a 69 kV bus (supplied by T-1/T-13/T-15). The substation has five 13.8 kV distribution circuits, Inkerman, Sherwood, Queens Arms, Mount Edward and University Avenue. There are two 13.8 kV substation transformers (15/20 MVA each: [Co.# 31, 1972 vintage, 69 kV – 13.8 kV] and [15/20 MVA, Co.# 42, 1976 vintage, 69 kV – 13.8 kV]) that are paralleled. The substation is not equipped with a mobile transformer bay. The summer and winter peak load is 19.8 MVA and 19.8 MVA respectively. The peak load represents 66 per cent of the combined ONAN rating and 50 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with UPEI and/or Charlottetown Plant Substations in order to reduce the impact of a potential outage.

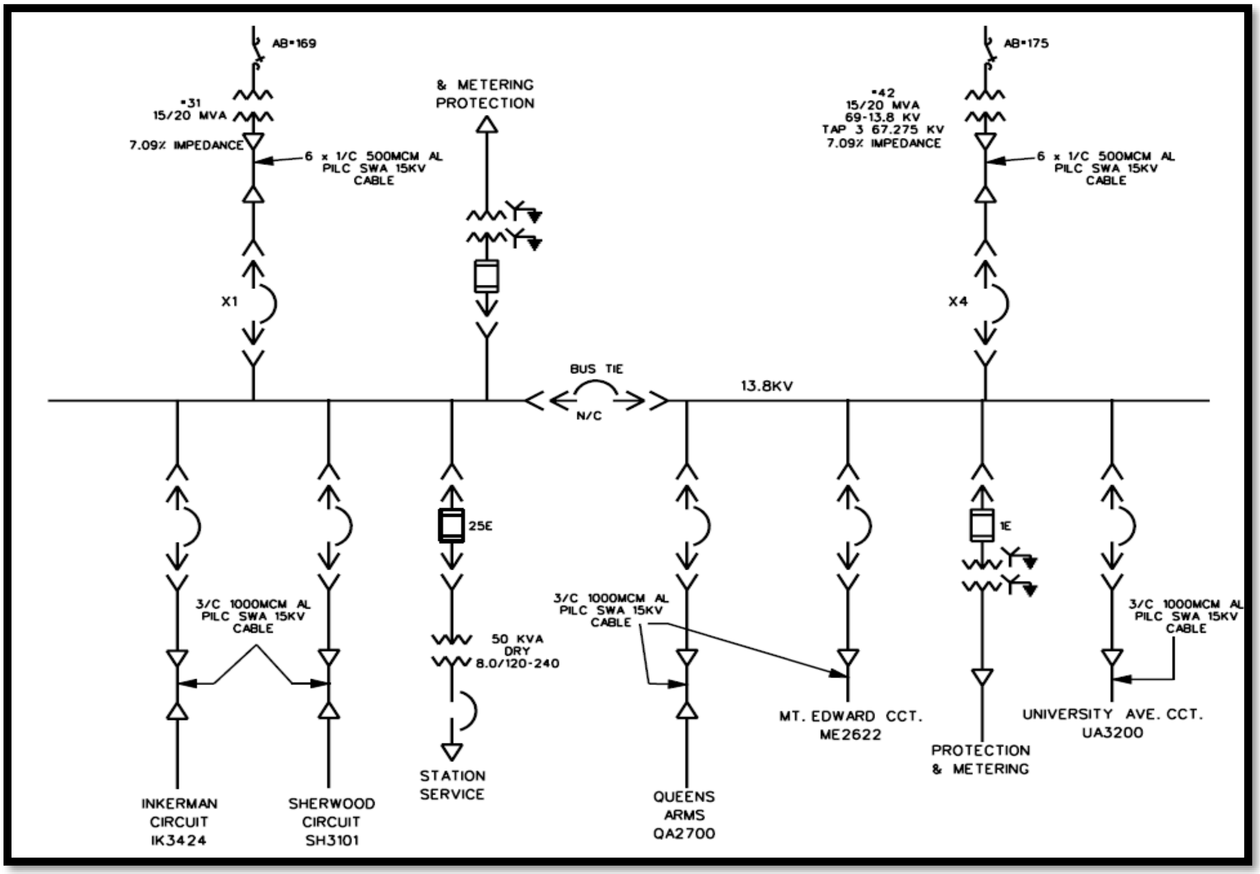

Figure 44: Single-Line Diagram of West Royalty Substation

2.1v West Royalty Rural Distribution System

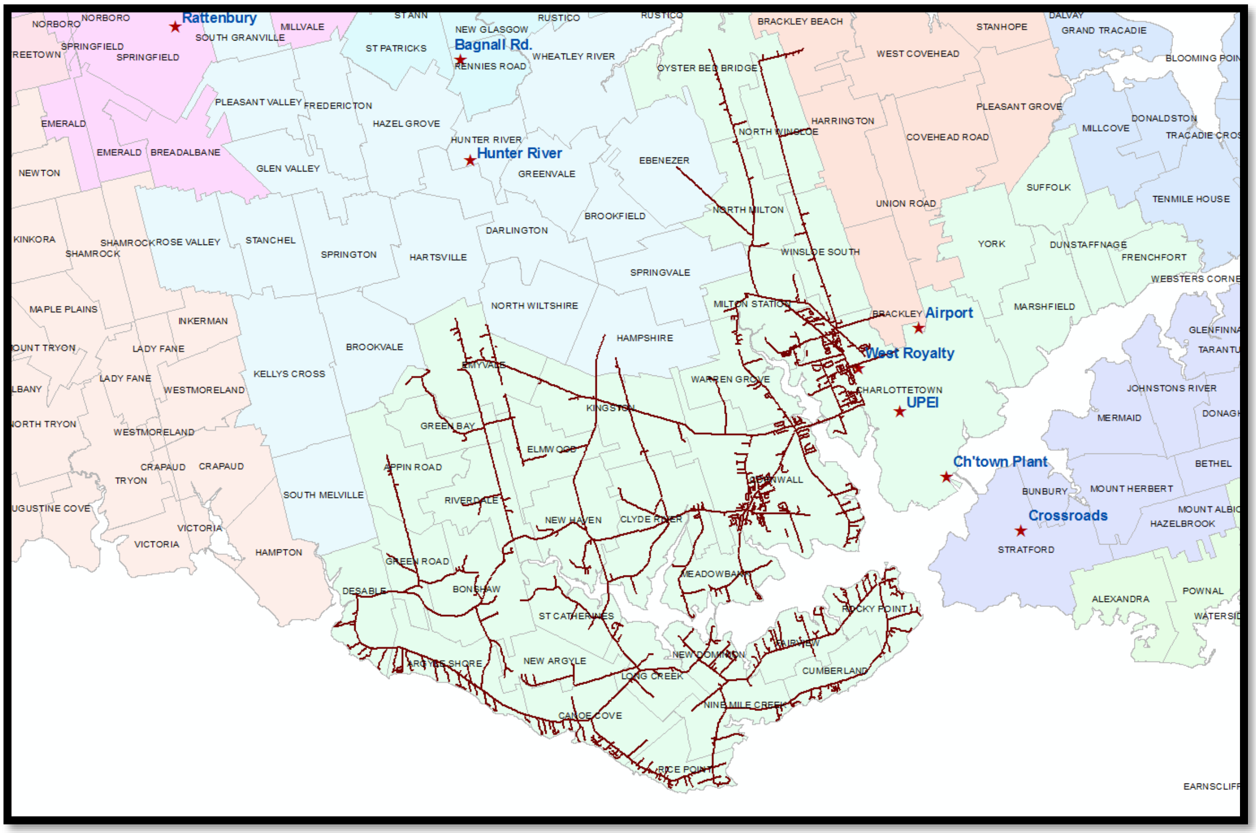

Figure 45: Service Area of West Royalty Rural Substation

The West Royalty Substation also has three 25 kV distribution circuits feeding Milton-Brackley, Bonshaw and the West Royalty Business Park. There are two substation transformers (15/20 MVA each: [Co.# 56, 1994 vintage, 69 kV – 25 kV/13.8 kV] and [Co.# 62, 1972 vintage, 69 kV – 25 kV/13.8 kV]) that are paralleled. There is no mobile transformer bay in the West Royalty Substation. The summer and winter peak load is 22.0 MVA and 31.7 MVA respectively. The winter peak is 106 per cent of the combined ONAN rating and 79 per cent of the combined ONAF rating. If needed, and depending on load condition, this substation can be paralleled with the Airport Substation in order to reduce the impact of a potential outage.

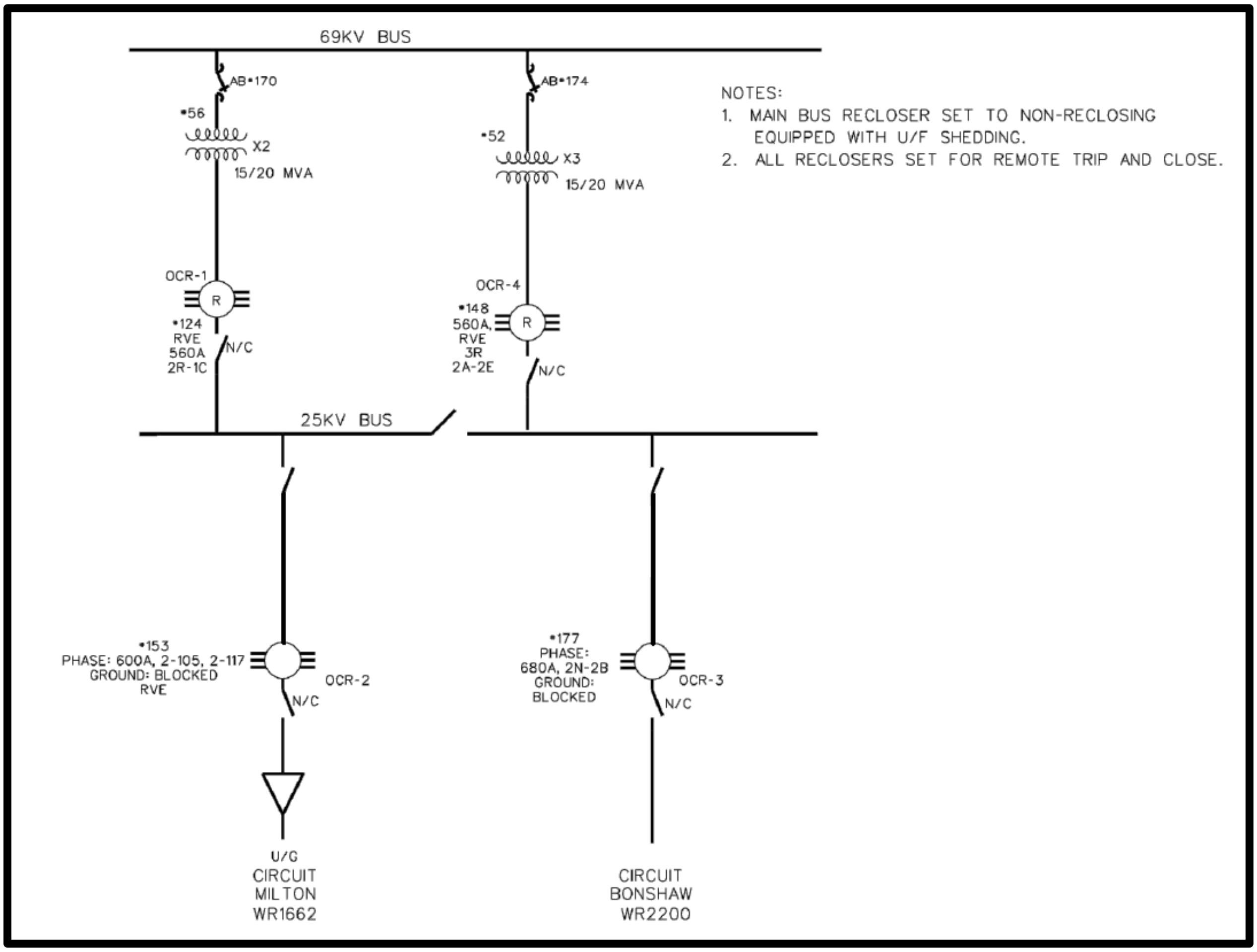

Figure 46: Single-Line Diagram of West Royalty Rural Substation

2.1w West St. Peters Distribution System

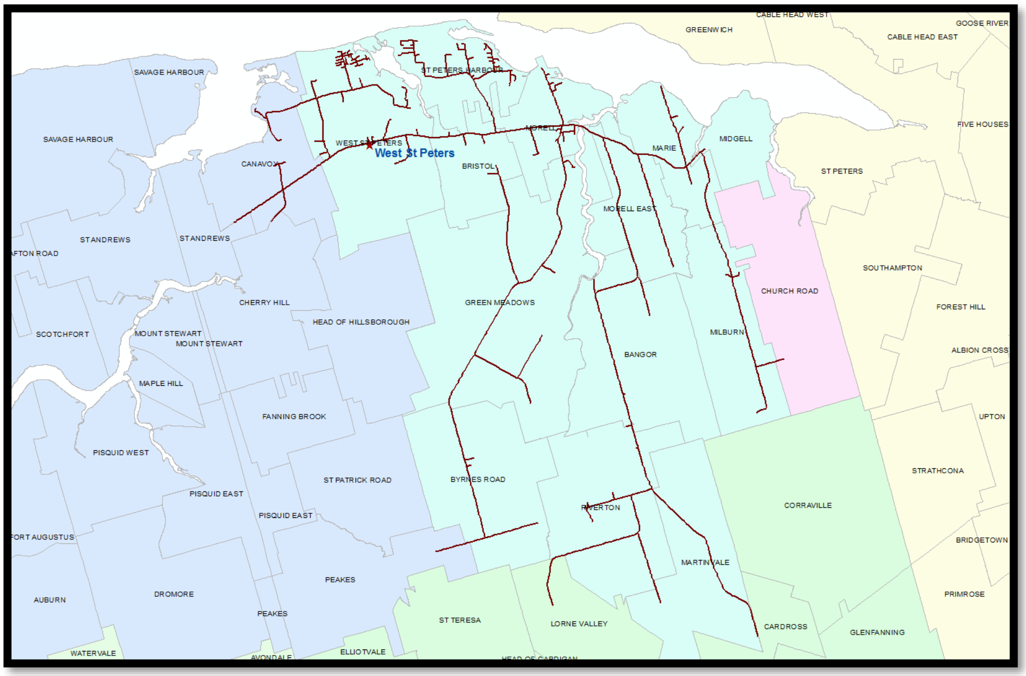

Figure 47: Service Area of West St. Peters Substation

The West St. Peters Substation ("WP") is located at 8807 St. Peters Road, West St. Peters. The substation is fed from 138 kV transmission line Y-104 that is out of the Church Road Switching Station and West Royalty Substation. The substation has three distribution circuits, Morell, St. Andrews and Wyman's. The substation has an on load tap changer for voltage regulation and uses bus PT's and transformer CT's for metering. The substation is equipped with a mobile transformer bay, and can accept mobile transformer Co.# 79. There is one substation transformer (7.5/10 MVA, Co.# 75, 2015 vintage, 13.8 kV – 12.5 kV) that has a summer peak load of 7.8 MVA and a winter peak load of 4.4 MVA. The summer peak load represents 104 per cent above the ONAN rating and 78 per cent of the ONAF rating. If needed, and depending on load condition, this substation can be paralleled with Dingwells Mills and/or Scotchfort in order to reduce the impact of a potential outage.

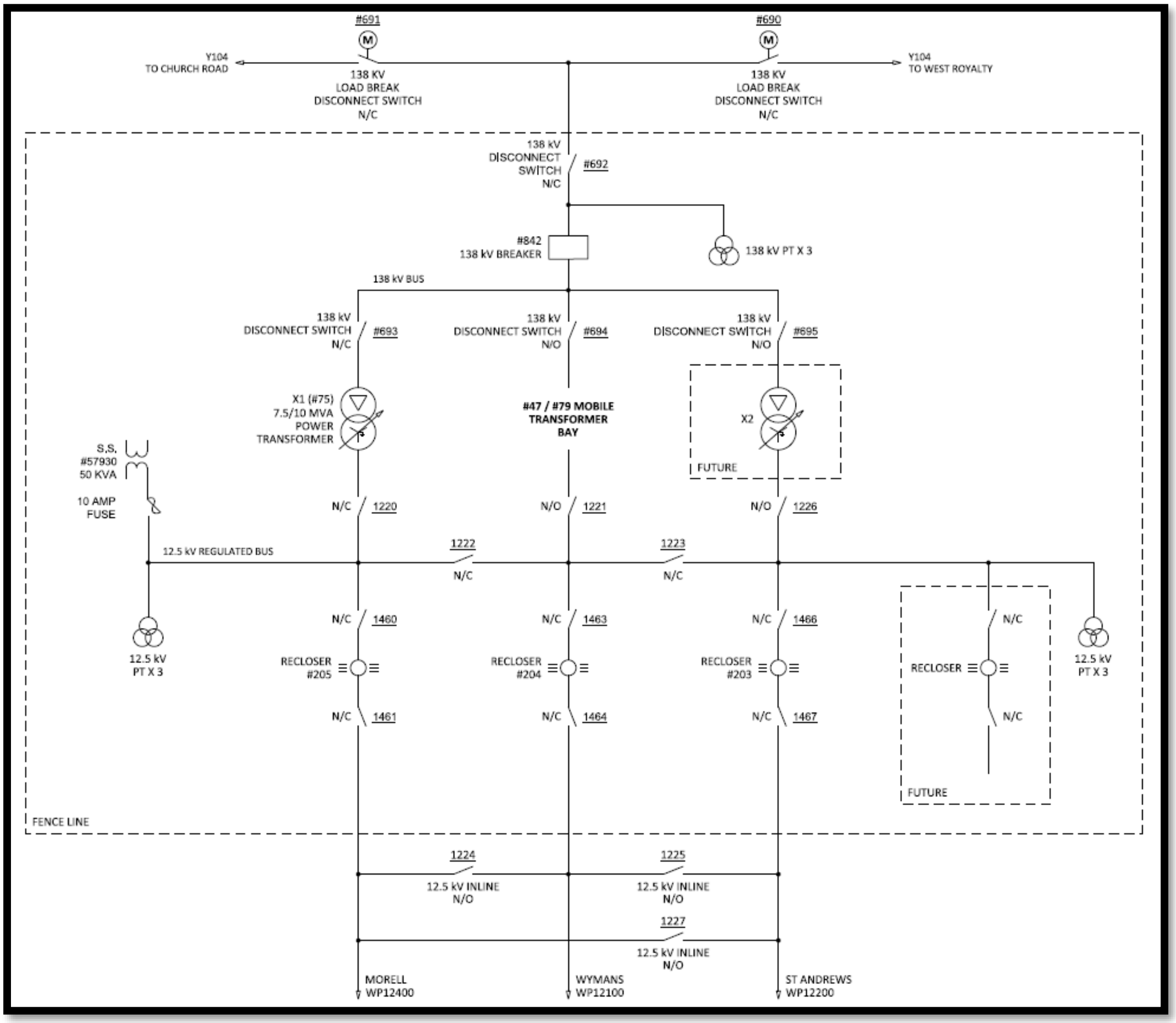

Figure 48: Single-Line Diagram of West St. Peters Substation

2.2 Summary of Distribution Managed Assets

The following is information that is accurate as of July 2020:

Table 1 Maritime Electric's Distribution Assets	
Customers	**79,497**
System Peak	**287 MW**
Distribution Lines	**5,372 km**
a. Overhead Lines	5,329 km
Three Phase	1,294 km
Single Phase	4,035 km
b. Underground Lines	43 km
Three Phase	11 km
Single Phase	32 km
Poles	144,900
Distribution Substations	**22**
Substation Transformers	32
Distribution Transformers	37,956
Padmounts	1,154
Polemounts	36,802
Reclosers	100
Voltage Regulators	142
Capacitor Banks	144
Metering Tanks	86

3.0 DISTRIBUTION ASSETS

3.1 Identification of Managed Assets

Maritime Electric has had a Maintenance and Asset Replacement Program underway for some time. The program includes the assessment of the condition of equipment and development of an asset maintenance and replacement cycle for distribution equipment. Asset inspection and maintenance cycles include four categories: visual inspections, mechanical operation inspections, electrical testing, and overhaul maintenance. Overhaul maintenance incorporates a scheduled shut down and de-energization of equipment.

3.2 Geographic Information Systems

For the most part, Maritime Electric's poles, transformers, meters, line connectivity and street lights are managed within a corporate Customer Information System ("CIS"). Employees access the data in various ways including CIS screens, reports and the Company's geographic information system ("GIS System"). The data is also used by other systems including the Outage Management and Work Management Systems, for power system planning and with AutoCAD design tools.

3.3 Overhead Distribution Managed Assets

The following is a listing and brief description of each type of Distribution Managed Asset ("DMA") at Maritime Electric:

<u>Overhead Conductor</u>

Conductors, also called wires or cables, run from pole to pole or pole to building, and carry the current from the source to the customers. Overhead conductor has several different characteristics:

- <u>Metal or Alloy</u>: Older conductors were mostly copper, but most modern applications use aluminum or aluminum alloys to save weight and cost;
- <u>Size/Gauge</u>: The size of the wire is selected based on power quality and reliability. Cost of losses calculations are also considered as losses are usually much more limiting than maximum current allowances. Larger conductors cost more, weigh more, and can take longer to install, but they can carry more current (i.e., they have a higher ampacity) and can have a longer useful life;
- <u>Insulation</u>: Some conductors have one or more layers of insulation on them. This is necessary if they are bundled together or are installed in a location where they can be expected to be contacted by vegetation or the public. The bundled cable has two insulated and one bare conductor, and is used for supplying a typical 'house service'. Most primary/high voltage conductors are bare, as this saves costs and weight; and

- Single or Bundled: At lower voltages, to save space and add strength, more than one conductor may be twisted or lashed into a 'bundle'. This is most common for secondary or service wires.

Poles

Constructed of wood, steel, and occasionally concrete or resin composites, poles form the backbone of the overhead distribution system. Wooden poles are used in over 99 per cent of all cases. For distribution purposes, these range in height from 25' (7.6 m) to 75' (22.8 m). The typical height for a single circuit three phase pole is 45' (13.7 m). Poles come in several standard strengths known as classes, as defined by Canadian Standards Association ("CSA") specifications. A new wooden pole can be expected to last 50 years from the time of installation before it reaches the end of its useful life through deterioration, although it may be removed or replaced before that time as needs change.

Framing Assemblies

Framing assemblies are assorted hardware components installed on a pole that provide mechanical support and clearances, and electrical isolation/insulation for the various conductors and equipment required on an overhead distribution line.

It can include cross arms, insulators, brackets, bolts, washers, nuts and other hardware. Framing assemblies also include guying and anchors as required.

It should be noted that the specific choice of some of these components, such as insulators, will vary depending on the required voltage of the system.

Substation Transformers

Substation transformers are used to transform electricity from a transmission voltage to a distribution voltage. Typically, this will be a 10 MVA transformer used to transform electricity from a primary voltage (such as 69 kV) to a secondary voltage (such as 12.5 kV, 13.8 kV or 25 kV) useful to supply thousands of customers. New transformers now have on load tap changers. These tap changers ensure safe voltages are supplied to customers, and replace voltage regulators in substations. Currently the following substations have transformers with on load tap changers: UPEI, Wellington, Bagnall Road, Mount Albion, Airport and West St. Peters.

Mobile Transformers

Mobile transformers are used to transform electricity from a transmission voltage to a distribution voltage. The transformer and related equipment are on a trailer and can be installed in a substation if the substations transformer fails. Maritime Electric owns two mobile transformers:

One 10 MVA, 69 kV – 25 kV/12.5 kV, Co.# 47; and
One 10 MVA, 138 kV/69 kV – 25 kV/12.5 kV, Co.# 79.

Distribution Transformers and Voltage Regulators

Distribution transformers are used to transform electricity from one voltage to another. Typically, this will be from a primary voltage (such as 12.5 kV, 13.8 kV or 25 kV) to a secondary voltage (such as 120/240 Volts [“V”]) useful to one or more customers.

Pole top transformers can be found in a variety of sizes, ranging from 3 kVA to 100 kVA. Most distribution transformers change a high voltage primary voltage (12.5 kV or 25 kV) to one of Maritime Electric’s three standard secondary voltages: 120/240 V single phase, 120/208 V three phase, and 347/600 V three phase.

Some specialized units, known as step downs, provide a smaller, yet still primary, voltage. The majority of step downs at Maritime Electric are used in the 25 kV system to supply electricity at 12.5 kV and vary in purchase year from 1971 to 2015. The Company is working to retire older step downs though voltage conversions or replacements.

Voltage regulators are a form of transformer that automatically maintains line voltages within a narrowly specified range and provides the ability to maintain CSA standard voltages at substations, on long feeders or on feeders with larger than typical loads.

Overhead Switches and Switchgear

This type of DMA allows for opening and closing of current carrying components, which either prevents or allows the flow of electricity. Switches can have different characteristics:

- Gang operated or single phase operated: A gang operated switch, generally a three phase device, allows all three phases of the switch to be opened or closed at once, often from the ground;
- Switchgear: Switchgear is a combination of electrical disconnect switches, fuses or circuit breakers used to control, protect and isolate electrical equipment;
- Load break or non load break: A load break switch allows for the interruption of power flow even when a significant amount of current is flowing;
- Remote controlled or locally operated; and
- Dielectric: The medium used by the switch to interrupt or insulate can vary; however, most use air while others use vacuum.

Protective and System Devices

Aggregated into this DMA group are:

- Reclosers and distribution circuit breakers;
- Capacitors of two types: Fixed (always 'on') or switched (only 'on' under specific conditions); and
- New system device evaluations: Maritime Electric is constantly evaluating new system devices in an effort to improve system reliability. Currently, fault indicators are being evaluated. Fault indications are devices hung on a distribution line to assist line crews with fault location. Maritime Electric is also evaluating using reclosers to tie two substation distribution systems together for minimizing recovery time in case of an outage. The "tie reclosers" are connected to Maritime Electric's communication network and therefore are visible to, and can be controlled by ECC operators.

Revenue Metering and Metering Tanks (CT's/PT's)

This item includes:

- Revenue meters that measure, store and report electricity usage;
- Primary (polemounted) instrument transformers (i.e., metering tanks) which include a combination of CT's and PT's; and
- Any communications or data aggregation equipment owned by Maritime Electric used to facilitate the revenue metering process.

4.0 INSPECTION AND MAINTENANCE PROGRAMS

4.1 Inspection and Maintenance (General)

Expenditures on inspection and maintenance programs are an integral aspect of any DAMP and good utility practice. Effectively maintaining existing line and substation equipment is necessary to keep equipment in good working condition, maximize equipment lifespan, and improve reliability by reducing the probability of failure. Maintenance programs optimize the value of capital investments. Maintaining equipment in proper working condition reduces the probability of equipment failure, enhances safety and increases reliability of supply to customers.

Maintenance activities at Maritime Electric are performed with a combination of internal personnel and qualified outside contractors and consultants. Inspection and maintenance activities can be subdivided into four basic categories:

Predictive Maintenance:

This is the identification of equipment deficiencies that may lead to failure. Examples of predictive maintenance activities are visual inspections, equipment testing, and substation transformer dissolved gas analysis. Thorough inspection is the primary mechanism used at Maritime Electric for predictive maintenance, although other methodologies are used, such as pole condition testing.

Corrective Maintenance:

This is the repair of equipment as a result of deficiencies identified through visual inspections or testing.

Preventive Maintenance:

Preventative maintenance is the routine servicing or repair of equipment on a regular schedule to ensure that equipment remains in good working condition. Preventative maintenance is undertaken at specific time intervals and is applied regardless of equipment condition. Examples of preventive maintenance activities are vegetation management, switch maintenance, protective device maintenance, and substation equipment maintenance.

Certification Maintenance:

Certain assets require periodic certification or recertification. This generally involves testing, calibration, and documentation (such as a 'seal' or 'sticker') by a third party accredited or industry accepted expert group, or by Maritime Electric personnel. Examples of managed assets requiring certification:

- Revenue meters and instrument transformers (residential, commercial/industrial, and bulk);
- Insulated booms on bucket trucks;
- Working grounds used by power line workers;
- Lifting capacity of material handler trucks; and
- Rubber cover up and rubber gloves.

Maritime Electric Equipment Maintenance and Asset Replacement Program:

The following guideline is used to aid with the goals and objectives of a formal equipment maintenance and asset replacement program. The following equipment maintenance guidelines are used to determine what level of maintenance is required:

a. Maintenance I: Procedures performed in the shop on new equipment.

b. Maintenance II: A detailed inspection consisting of diagnostic tests to determine if the equipment is functioning adequately. Some equipment does not require overhauls.

c. Maintenance III: Procedures performed at the end of a maintenance cycle as outlined below or as a result of a fault detected during inspections. The objective is to overhaul the equipment and prepare for another maintenance cycle.

d. Maintenance IV: Procedures performed during an unscheduled maintenance activity due to equipment malfunction. Where the malfunction had or could have caused an outage, a limited amount of maintenance will be done if the equipment cannot be taken out of service or there is no spare. If the option to use a spare is available, then Maintenance II will be performed on that equipment.

Table 2 Distribution Equipment Maintenance Cycles			
Equipment	**Visual Inspection Cycle (Maintenance I)**	**Electrical Testing Cycle (Maintenance II)**	**Scheduled Overhaul (Maintenance III)**
Underground			
Underground Vaults	1 year	N/A	NA
Underground Cables and Accessories	5 years	10 years (Hi-pot)	NA
Switches			
Padmount and Metal Clad Switchgears	N/A	5 years	10 years
Transformers			
Substation Transformers	2 month	10 years	10 years
Transformer Oil Sampling	NA	1 year (Analysis-DGA, color, dielectric, etc.)	NA
Voltage Regulators	3 month	5 years (Substation) 7 years (Feeder)	5 years (Substation) 7 years (Feeder) or 150,000 operations
Substation and Feeder Equipment			
Metering Tanks	2 month	10 years	10 years
Reclosers	3 month	5 years (Substation) 7 years (Feeder)	5 years (Substation) 7 years (Feeder) or 200 fault operations
Substation Equipment Oil Sampling	NA	5 years (Dielectric)	NA
Capacitors (with controllers)	1 month	5 years	5 years
Substation Miscellaneous Equipment (i.e., structures, buswork, insulators, lightning arresters, yard lighting, foundations, grounding, control cables, building, yard, station service)	2 month (thermoscan annually)	N/A	N/A

Equipment maintenance report forms are used to record information and data based on the equipment maintenance guidelines.

Equipment installation forms are used to record information on settings, location of equipment, installation checks, and all other necessary data required to update Maritime Electric's equipment database.

4.2 Line Maintenance Activities (General)

Maritime Electric establishes its various line maintenance cycles to achieve a number of objectives:

- Coordinating inspections;
- Inspecting critical assets more frequently and making use of more sophisticated inspection methods (e.g., thermographic scans at substations or in vaults or pole testing);
- Scheduling preventative maintenance activities on cycles that attempt to optimize the life cycle costs of equipment considering the equipment manufacturer's recommendations, good utility practice as well as Maritime Electric past experience;
- Scheduling preventive maintenance activities with cycles greater than one year in a way that levels expenditures from year to year; and
- To the extent possible, scheduling preventive maintenance activities with cycles greater than one year in a way that levels the amount of work assigned to each service centre from year to year. This ensures adequate resource availability to complete the planned program and minimizes travel costs associated with crews traveling between service centers.

The major types of line maintenance activity are described as follows:

<u>Predictive Maintenance</u>

Predictive maintenance on overhead and underground distribution systems generally takes the form of visual inspections and equipment testing.

In 2017, Maritime Electric initiated a Distribution Inspection Program as a proactive way to improve reliability through identifying components of the distribution system that are unsafe or at risk of failure. The program was designed to ensure that all overhead primary distribution lines are subject to a detailed ground inspection every six years. The inspections assess and document any deficiencies found with distribution assets such as poles, cross arms, guy wires, conductors and cables, insulators, arrestors, polemount transformers and switching devices (fused cutouts, load break and disconnect switches, etc.). Padmount transformers and civil facilities, such as transformer pads and cable conduits are inspected more frequently, on a three-year cycle. Assets such as reclosers, voltage regulators, and capacitor banks installed on poles are inspected every three months. Thermographic scans of critical distribution line components and transformers (in vaults or above ground in transformer rooms) are conducted on an annual basis. Deficiencies observed through the Distribution Inspection Program are recorded and prioritized for correction action.

The Company has a Field Asset Maintenance System ("FAMS") where all maintenance items identified through inspections are recorded for future assignment to Maritime Electric field staff. Maintenance items reported by customers are also collected and stored for assignment through the FAMS.

The maintenance items in FAMS are assessed on the basis of the potential for failure and consequential impact on safety or reliability. They are then prioritized for corrective action as follows:

- Major deficiencies, where repair or replacement is required to address a pending failure or safety hazard. Examples of major deficiencies would be broken poles and cross arms; and
- Minor deficiencies, where the deficiency is of a nature where action can be deferred for a time. An example would be a blown lightning arrestor. Repairs to less critical deficiencies are typically planned so that a group of deficiencies within a given area can be addressed by a single crew in a short timeframe.

Corrective Maintenance

Any deficiencies identified through unscheduled inspections are also recorded and prioritized as described above. Repairs or replacements are carried out accordingly and completion is tracked.

Preventive Maintenance

Three major preventive maintenance activities are conducted on distribution lines and equipment:

Vegetation Management

Maritime Electric's Vegetation Management Program is moving towards achieving a seven year cycle, which is believed to be necessary with regrowth rates experienced in recent history. In some areas, limbs and foliage are trimmed back to achieve separation from energized components in a manner that generally allows for good reliability with regrowth between control cycles. In other areas, ground cutting is used to clear the corridor with the line assets, to allow for longer periods between vegetation control efforts. Ground cutting is more cost effective over the long term.

Spot trimming or branch removal in any specific areas where faster than typical growth has occurred, or where one or more damaged branches have entered the minimum clearance zone from outside the vegetation control space, is done on an as needed basis.

Switch Maintenance

Maritime Electric has a formal Switch Maintenance Program for high voltage 69 kV and 138 kV gang operated switches. It does not, however, currently have a formal inspection and maintenance cycle for medium voltage distribution gang operated switches in the distribution system.

Protective Device and Voltage Regulator Maintenance

Maritime Electric performs routine inspection and maintenance of its reclosers and voltage regulators. Maintenance activities are typically performed on a five year cycle for substation reclosers and voltage regulators and a seven year cycle for distribution line reclosers and voltage regulators, and include the following main activities:

- Determination of number of operations since the date of last maintenance, to verify that existing maintenance intervals are adequate;
- Visual inspection of tanks, bushings, contacts, operating mechanisms, control boxes, etc., to identify any broken or deteriorated parts and evidence of surface tracking or corrosion;
- Testing of operations, both manually and using electrical test equipment to ensure proper operation; and
- Electrical testing (ratio, resistance, etc.) to verify electrical integrity of device and all components.

The results of any tests performed are documented on equipment test forms and kept on file for trending and comparison purposes.

4.3 Distribution Substation Maintenance Activities (General)

<u>Predictive Maintenance</u>

Predictive substation maintenance is integral to maintaining reliability and detecting potential equipment failure. Since substation equipment typically requires large investments for installation and since failure of substation components can affect large numbers of customers, detecting potential failures before they occur is very important. As described below, there are presently three key predictive maintenance activities conducted in Maritime Electric substations, with equipment specific methodologies provided in Section 4.4:

Visual Inspections

Visual inspections are essential for assessing the condition of substation components and identifying deterioration or areas where attention is required. Maritime Electric typically conducts detailed visual inspections on each of its distribution substations once every two months.

Substation buildings, fences, and electrical components (buswork, switches, insulators, transformers, ground conductors, reclosers, metering tanks, voltage regulators, etc.) are inspected and any deficiencies recorded. In addition, data such as relay targets, breaker counters, direct current system voltage, and substation transformer gauge readings are recorded. The condition of ancillary equipment such as lighting, eyewash stations, first aid kits, and oil spill kits is also inspected. During these bi-monthly inspections, the remainder of the substation is visually inspected at a high level and deficiencies requiring immediate correction are identified. Any deficiencies noted during inspections are recorded, reported, and are then prioritized for corrective action.

Transformer Dissolved Gas Analysis

Dissolved Gas Analysis ("DGA") is an effective tool for assessing the condition of substation power transformers and identifying deterioration in substation transformer oil or insulation. DGA can also identify whether arcing or acid build up is occurring inside the transformer. DGA tests for the presence of dissolved gas and water in transformer insulating oil, and based on the level of gas(es) or moisture present; assess the condition of the transformer. An important aspect of DGA is the trend analysis, which reviews the history of dissolved gas levels in the transformer.

DGA is performed annually on all transformers in Maritime Electric substations, whether in service or spare. Maritime Electric uses qualified personnel to perform the analysis, provide reports on transformer condition, and recommend any required actions if gassing is above normal levels or if acids are detected. Corrective action to deal with abnormalities is essential to prevent failure and extend the life of the transformer.

Thermographic Scanning

Thermographic (infra-red) scanning is scheduled annually for all distribution substations. Thermography captures the temperature of components compared to surrounding equipment and ambient temperature, and high relative temperatures can be indicative of overloaded or deteriorated components.

Corrective Maintenance

Corrective maintenance is a reactive activity that takes place when deficiencies in substation components are identified. Defective components are prioritized for repair or replacement on the basis of the severity of the condition, the criticality of the equipment, and the potential impact of failure on safety or service reliability.

Preventive Maintenance

Preventive maintenance on substation components is conducted on a regular basis and is integral to keeping equipment in good working condition. Substation components typically undergo preventive maintenance on a five year cycle, including inspecting, cleaning, lubricating, and testing. The major activities described below are included in this program, with specific equipment methodologies provided in Section 4.4.

- Transformers (Distribution and Instrument): Inspection and cleaning, DGA, Doble testing, on-line tap changer maintenance (including oil refurbishment and contact inspection and replacement as required), and inspection and cleaning of gauges, access ways, bushings and connections;

- Recloser Maintenance: Inspection, cleaning of bushings, connections, contacts and moving parts, contact resistance and insulation testing;
- Switch Maintenance: Inspection and cleaning of bushings, connections, contacts, arc horns, and operating mechanisms and insulation testing;
- Oil Renewal: Replacing insulating oil in substation transformers, and oil insulated circuit breakers and potential transformers as needed, to ensure insulating oil is clear of contaminants; and
- Accessories: Other equipment such as motor operators and heating elements are inspected, cleaned, and maintained.

4.4 Substation Equipment Maintenance Methodologies (Type Specific)

Predictive Maintenance Methodologies:

Predictive maintenance methodologies for specific types of substation equipment are as follows:

Overhead Switches

- Inspect the insulators for breaks, cracks, burns, or cement deterioration. If necessary, clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces;
- Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona;
- Check cutouts for damaged fuses and replace if necessary; and
- Scan the switch with an infrared scanner to check for further defects.

Underground Switches and Junction Units

- Scan the switch with an infrared scanner to check for defects.

Surge Arrestors

- Check for cracked, contaminated, or broken porcelain; loose connections to line or ground terminals; and corrosion on the cap or base; and
- Check for pitted or blackened exhaust parts or other evidence of pressure relief.

Buses and Shield Wire

- Inspect bus supports for damaged porcelain and loose bolts, clamps, or connections;
- Observe the condition of flexible buses and shield wires; and
- Inspect suspension insulators for damaged porcelain (include line entrances).

Structures

- Inspect all structures for loose or missing bolts and nuts;
- Observe any damaged paint for galvanizing or signs of corrosion; and
- Inspect for deterioration, buckling, and cracking.

Grounding System

- Check all above grade ground connections at equipment, structures, fences, etc.; and
- Observe the condition of any flexible braid type connections.

Control and Metering Equipment

- Check current and potential transformers for damage to cases, bushings, terminals, and fuses;
- Verify the integrity of the connections, both primary and secondary;
- Observe the condition of control, transfer, and other switch contacts; indicating lamps; test blocks; and other devices located in or on control cabinets, panels, switchgear, etc. Look for signs of condensation in these locations;
- Examine meters and instruments externally to check for loose connections and damage to cases and covers. Note whether the instruments are reading or registering;
- Open and close each potential switch on the test block to determine whether the speed of the meter disk changes. Repeat the process with the current switches. Changes of speed should be approximately the same for each meter element;
- Check the status of relay targets (where applicable);
- Make an external examination of relays, looking for damaged cases and covers or loose connections;
- Check the station battery for loose connections and battery cells for low level or low specific gravity of the electrolyte. Record the electrolyte temperature;

- Inspect the station battery charger. Check the charging current and voltage. Observe the ground detector lamps for an indication of an undesirable ground on the direct current ("DC") system; and
- Check the annunciator panel lights.

Metal Clad Switchgear

- Inspect for damage to enclosures, doors, latching mechanisms, etc.;
- Inspect bus supports for signs of cracking;
- Verify that all joints are tight;
- Check the alignment of all disconnect devices, both primary and secondary, including those for potential transformers;
- Inspect terminal connections and the condition of wiring;
- Check rails, guides, rollers, and the shutter mechanism;
- Inspect cell interlocks, cell switches, and auxiliary contacts;
- Inspect control, instrument, and transfer switches; and
- Inspect for broken instrument and relay cases, cover glass, etc., and check for burned out indicating lamps.

Cables

- Inspect exposed sections of cable for physical damage;
- Inspect the insulation or jacket for signs of deterioration;
- Check for cable displacement or movement;
- Check for loose connections; and
- Inspect shield grounding (where applicable), cable support, and termination.

Foundations

- Inspect for signs of settlement, cracks, spalling, honeycombing, exposed reinforcing steel, and anchor bolt corrosion.

Substation Area General

- Verify the existence of appropriate danger and informational warning signs;
- Check indoor and outdoor lighting systems for burned out lamps or other component failures;
- Verify that there is an adequate supply of spare parts and fuses;

- Observe the condition of hook sticks;
- Inspect the fire protection system and the provisions for drainage in the event of leaking oil;
- Check for bird nests or other foreign materials in the vicinity of energized equipment, buses, or fans;
- Observe the general condition of the substation yard, noting the overall cleanliness and the existence of low spots that may have developed;
- Observe the position of all circuit breakers in the auxiliary power system and verify the correctness of this position; and
- Inspect the area for weed growth, trash, and unauthorized equipment storage.

Substation Fence

- Check for minimal gap under the fence or under the gate. Ensure that all gaps are less than 50 mm at any point under the fence and less than 100 mm at any point under the gate;
- Ensure the fence fabric is intact and there is no rust;
- Check that the barbed wire is taut;
- Ensure the gate latches are operable;
- Ensure flexible braid type connections are intact; and
- Verify that no wire fences are tied directly to the substation fence.

Preventive Maintenance Methodologies:

Preventative maintenance methodologies for specific types of substation equipment are as follows:

Inline Switches (Non-Gang Operated)

- Open/Close the switch several times. Periodic operation of the switch is recommended as this ensures the hinge pivot point is operating smoothly and helps clean any oxide from the jaw contacts, which may have formed since the last maintenance;
- Check for simultaneous closing of all blades and for proper seating in the closed position;

- Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction;
- Inspect the insulators for breaks, cracks, burns, or cement deterioration. If necessary clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces;
- Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona;
- Where the switch blade has been left open for an extended period of time, if necessary, the jaw and blade contacts should be wiped clean of any dirt particles to ensure that there will be no plating damage to the contacts and that they will properly mate. If necessary, thinners or acetone may be used to clean the contacts and if the contacts are heavily coated use a fine Scotch-Brite® pad;
- Scan the switch with an infrared scanner to check for further defects; and
- In addition to the above, perform the switch maintenance that is specified in the Maritime Electric maintenance report.

Gang Operated Switches

- The switch should be disconnected from all electric power sources before servicing;
- Ground leads or their equivalent should be attached to both sides of the switch;
- Inspect the insulators for breaks, cracks, burns, or cement deterioration. Clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces;
- Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction. Replace damaged or badly eroded components. If contact pitting is of a minor nature, smooth the surface with clean, fine sandpaper (not emery) or as the manufacturer recommends. If recommended by the manufacturer, lubricate the contacts;
- Inspect arcing horns for signs of excessive arc damage and replace if necessary;

- For all S&C Alduti-Rupter brand switches, perform the outlined continuity check and additional maintenance as outlined in the Alduti-Rupter Switch, General Maintenance Outline;
- Check the blade lock or latch for adjustment;
- Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona. Check corona balls and rings for damage that could impair their effectiveness;
- Inspect inter-phase linkages, operating rods, levers, bearings, etc., to assure that adjustments are correct, all joints are tight, and pipes are not bent. Clean and lubricate the switch parts only when recommended by the manufacturer. Check for simultaneous closing of all blades and for proper seating in the closed position. Check gear boxes for moisture that could cause damage due to corrosion or ice formation. Inspect the flexible braids or slip ring contacts used for grounding the operating handle. Replace braids showing signs of corrosion, wear, or having broken strands;
- Power operating mechanisms for switches are usually of the motor driven, spring, hydraulic, or pneumatic type. The particular manufacturer's instructions for each mechanism should be followed. Check the limit switch adjustment and associated relay equipment for poor contacts, burned out coils, adequacy of supply voltage, and any other conditions that might prevent the proper functioning of the complete switch assembly;
- Inspect overall switch and working condition of operating mechanism. Check that the bolts, nuts, washers, cotter pins, and terminal connectors are in place and in good condition. Replace items showing excessive wear or corrosion. Inspect all bus cable connections for signs of overheating or looseness; and
- Inspect and check all safety interlocks while testing for proper operation.

Substation Transformers

- Inspect the control cabinet, control relays, contactors, indicators, and the operating mechanism;
- Look for loose, contaminated, or damaged bushings; loose terminals; and oil leaks;
- Check oil levels in main tanks, tap changer compartment, and bushings;
- Inspect the inert gas system (when applicable) for leakage, proper pressure, etc.;

- Read and record the operations counter indicator reading associated with the load tap changer;
- Observe oil temperature. Oil temperature should not exceed the sum of the maximum winding temperature as stated on the nameplate plus the ambient temperature (not to exceed 40 degrees Celsius [ºC]) plus 10ºC. Generally, oil temperature does not exceed 95ºC and 105ºC for 55ºC and 65ºC winding temperature rise units, respectively; since the ambient temperature rarely exceeds 30ºC for periods long enough to cause an oil temperature rise above these points;
- Perform the power factor test;
- Perform the turns ratio test;
- Perform the winding resistance test;
- Perform the excitation current test;
- Perform the insulation resistance test;
- Send sample to lab for DGA; and
- In addition to the above perform the transformer maintenance that is specified in the Maritime Electric maintenance report.

4.5 Revenue Metering and Instrument Transformer Maintenance

Revenue metering and instrument transformer assets require certification maintenance in addition to the typical 'physical' maintenance (predictive, corrective, and preventative) required by most other types of DMA. Typically, each class of revenue meter and instrument transformer (current transformers and potential/voltage transformers) must be recertified by an accredited testing organization on a recurring basis.

The frequency and nature of these recertifications are dictated by regulations enforced by Measurement Canada (Industry Canada), a Federal Government regulator. In the past, these regulations have allowed for sample testing and 'family' testing of entire groups of revenue meters rather than full testing of each and every individual meter. Whatever method is used to recertify a group of meters, meticulous and detailed records must be maintained for every individual meter and retained throughout the life of the meter.

5.0 SYSTEM PERFORMANCE AND RELIABILITY

5.1 General

Maritime Electric does not rely solely on regulation as the impetus to maintain a high level of service and believes that meeting customer expectations for system performance is part of its mission as a corporation. As part of managing system performance, Maritime Electric prepares reports on a monthly, quarterly, and annual basis for all service quality indicators.

Maritime Electric monitors system performance metrics to determine what trends, if any, are developing. The reliability indicators assist in developing the programs within the DAMP through root cause analysis. Capital investments made over the past few years are yielding favourable results, as reliability has improved. Significant work has taken place in specific areas where the infrastructure was visibly aging, or where trend analysis indicated deficiencies.

5.2 Reliability Analysis

A key objective of the DAMP is to maintain a high level of distribution system reliability. Capital investments are aimed at improving or maintaining reliability by proactively upgrading deteriorating facilities and adding system capacity to avoid overloads. Investments are also made to ensure that sufficient system redundancy exists so that customers can be supplied from alternate paths in emergency or planned outage situations. Investments in technology such as supervisory control and data acquisition ("SCADA") provides real time system information that facilitates the rapid identification of system problems and remote switching to improve the efficiency of outage response.

In addition to the capital investments, maintenance programs and operational practices are also aimed at reliability. For example, in its service territories Maritime Electric maintains systematic vegetation management programs to maintain clearances between power lines and surrounding vegetation. In forced outage situations, outage response efforts focus on locating and isolated faulted areas promptly so that most affected customers can be restored from alternate paths. When system components must be taken out of service for planned maintenance, switching is carried out so as to minimize disruption to customers.

The application of SCADA technology allied to control room oversight is a key component of Maritime Electric operations, and also impacts reliability performance. Maritime Electric's Energy Control Centre ("ECC") is currently staffed on a 7 day/24 hour basis. The ECC provides efficient identification of system problems during normal workdays and after hours, which is an essential component of effective outage response.

Maritime Electric maintains databases of all outages that occur on its distribution system. This allows for the tracking and analysis of reliability performance. The two key indices are defined by CEA as follows:

- *System Average Interruption Duration Index* ("SAIDI") – reflects the total outage time to the average customer over a period of one year.
- *System Average Interruption Frequency Index* ("SAIFI") – reflects the number of interruptions to the average customer over a one year period.

Indices are computed on a monthly and annual basis. Data is submitted to IRAC in accordance with regulatory requirements. In addition, data is also analysed internally by Maritime Electric to identify reliability trends and potential areas for reliability improvement.

As an example of the data produced, SAIDI and SAIFI reliability indices for Maritime Electric's transmission and distribution over the five year time period 2016 to 2020 are shown in the following table:

Table 3
Maritime Electric CEA Reliability Indices for Years 2016 to 2020

Year	2016	2017	2018[2]	2019[3]	2020
SAIDI (hours)	11.13	3.96	23.83	40.19	4.98
SAIFI	3.69	2.61	6.75	5.50	2.19

2 November 29, 2018 – snow, ice and wind storm.
3 September 7, 2019 – post-tropical storm Dorian.

IEEE 2.5 Beta Method

An Institute of Electrical and Electronics Engineers (“IEEE”) working group has developed a statistical approach to the problem to define a Major Event Day (“MED”). Their recommendation, known as the 2.5 Beta Method, works as follows:

- A MED is any day that exceeds a daily SAIDI threshold called the Major Event Threshold (“T_{MED}”);
- Daily SAIDI values for the past five years are used to calculate T_{MED};
- The natural log ($\log_e$) of each SAIDI value is calculated and the $\log_e$-average (α) is calculated; and
- The standard deviation of the natural logarithms is calculated (β). Using an Excel spreadsheet and the standard deviation function (“STDEV”) the $\log_e$-standard deviation is calculated.

From this data, T_{MED} is,

$$\mathbf{T_{MED} = e^{(\alpha + 2.5 * \beta)}}$$

Where,

T_{MED} = Major Event Threshold, minutes

e = Euler’s number, 2.718

α = Log_e-average of the data

β = Log_e-standard deviation of the data

Below is a comparison between SAIDI (CEA) and SAIDI (IEEE MED Excluded).

Table 4 Comparison of SAIDI (CEA) and SAIDI (IEEE MED excluded)		
Year	**SAIDI (CEA)**	**SAIDI (IEEE MED Excluded)**
2016	11.13	2.46
2017	3.96	2.25
2018	23.83	3.25
2019	40.19	2.98
2020	4.98	2.57

One of the reasons to factor out major events is to normalize the SAIDI information. This helps to ensure that the utility is responding to real changes in its reliability indices and is not chasing variances caused by major events such as hurricanes, ice/sleet, storms and other such disturbances. Understanding how to correctly apply the IEEE standard reliability indices is the first step in measuring the reliability of an electric utility's distribution system. Major events are removed from the base data so that reliability measures are not distorted and to help the utility track improvements to the electric system.

6.0 DISTRIBUTION PLANNING

Prudent and timely planning lies at the core of any sustainable asset management program. At Maritime Electric, planning is a continuous and evolving process designed to meet the present and changing needs of a variety of stakeholders. This is accomplished through the general categories of planning described below, with ongoing interaction between all three types:

6.1 Long Term Planning (Forecast Horizon Typically 10 Years)

Long range distribution planning is generally performed through the preparation and periodic review of long term system planning studies for the organization. System planning studies analyze the existing transmission and distribution systems and anticipated customer load and generation changes over a planning horizon of 10 years. While system planning studies separately analyze the existing transmission and distribution systems, neither is done in isolation of the other given the interdependency of transmission on distribution and vice versa.

A long-term load (and generation) forecast is prepared, using the best information available at the time of the study. The load forecast is based on an econometric model using inputs such as load, number of customers, population growth, gross domestic product ("GDP") and consumer price index ("CPI"). The Company compiles future economic projections for the Island and incorporates these into the regression analysis.

Technical issues like component capacities, ability to operate within voltage requirements, and basic contingency analysis are reviewed, and system deficiencies (present and predicted through the load forecast period) are identified. Various alternatives and solutions are proposed and then analysed to ensure that they address all predicted deficiencies.

Maritime Electric is monitoring the adoption of electric vehicles ("EV's") on PEI. In 2020 Maritime Electric purchased an electric vehicle to operate within its fleet. This project will allow the Company to evaluate an electric vehicle in terms of operating and maintenance costs, practicalities of use, and overall value.

Widespread EV (either plug in hybrid or battery electric) adoption on PEI will require upgrades to various distribution system components including, but not limited to, protection devices, line and service conductor, distribution and substation transformers, and power quality equipment. Currently early adoption on PEI is low (under 100 EV's); however, as more EV's are purchased/imported to the Island, Maritime Electric will continue to monitor the impact to the grid and determine where and when upgrades are required. More details on the transmission and supply requirements of EV's can be found in the Company's Integrated System Plan ("ISP").

Generally, a complete long term system planning study for Maritime Electric will be performed at regular intervals of several years, with periodic reviews to ensure that the information and conclusions in each study are still reasonably accurate and valid as more recent data becomes available.

6.2 Medium Term Planning (Five Year Planning Horizon)

Maritime Electric uses results from its strategic planning and other reports, such as asset condition reports, to perform 'tactical' planning which covers a five-year period. Changes to the regulatory environment must be taken into account as well.

Medium term planning is performed each year, to incorporate new information that may arise, such as new regulations, increased load growth, longer term individual customer needs or updated asset condition reports. Typical inputs to medium term planning include:

- Customer driven needs;
- Municipal driven needs;
- Regulatory requirements;
- Reliability analysis;
- Asset evaluation and renewal requirements;
- Expansion requirements identified through long term planning; and
- Extraordinary initiatives, such as the electrification of transportation.

The results of this medium term planning set priorities, goals and targets to define optimal and sustainable levels of activity in all areas. The outcomes of tactical planning contribute directly to the corporate five year fiscal plan.

Heat pumps have become popular in recent years in addition to the increase in the percentage of customers using electric resistance heating as their primary source of heat. Heat pumps are being installed mainly by residential customers and some general service customers looking to displace a portion of their furnace oil usage with the added benefit of having air conditioning available in the summer. The shift to heat pumps has resulted in an increased peak load for both winter and summer.

In order to supply new load and decrease losses, a new 138/25 kV Clyde River Substation is being constructed. The new substation at Clyde River will serve load growth in residential and general service load in the area. Also, in the short term, a new substation at East Royalty will replace the aging Scotchfort Substation and serve residential growth in the area, which includes York and Suffolk. In the long term, Scotchfort Substation will be rebuilt and fed at 138 kV. Maritime Electric has identified the need for a new distribution substation in the Tignish area in the near future. A long term identification of needs is provided in the ISP, including information on Cavendish, Crapaud, Mount Pleasant, and Bedeque areas. In other areas, additional feeders may also be required to accommodate growth and decrease losses. The plan for these new substations and associated feeders is based on a projected residential and general service load growth that takes in consideration residential and general service electric heat load increase experienced in the last few years plus any additional industrial loads. Maritime Electric continuously monitors the load growth and adjust its plan depending on the pace and location of the load growth.

Maritime Electric is planning to replace a distribution substation power transformer each year for the next five years. These replacements are due to load growth and age/reliability and the first is scheduled for Rattenbury in 2021. The substations receiving a new transformer in 2022 and beyond will be determined based on load growth and age/reliability.

6.3 Short Term Planning (One Year Planning Horizon)

Short term or operational planning involves detailing the tasks required to complete current year projects as well as operate the distribution system in a safe and reliable manner. It also addresses short term needs, such as connection of a customer or development that was not identified previously during medium term planning, or reaction to external events such as a severe ice storm.

7.0 <u>ASSESSMENT OF ASSET CONDITION</u>

7.1 Distribution Substations

The nature of distribution substation equipment does not lend itself to purely quantitative evaluation of its condition. In addition, the relatively low quantity of each type of substation asset ensures that each item can receive regular inspection, maintenance, and qualitative assessment. Since each piece of substation equipment is also relatively expensive to replace, it is generally cost effective to perform regular maintenance on it rather than relying on run to failure techniques which make more sense for low value items like line insulators or cross arms. The following sections provide a summary of the condition of Maritime Electric’s distribution substation equipment:

7.2 Poles

A wooden utility pole generally remains useful until:

- It fails (breaks or collapses) due to severe weather, vehicle impact, or loss of strength associated with advanced aging;
- New requirements necessitate a pole change out. These needs might be for a taller or stronger pole to support more equipment;
- The pole is no longer required at its legacy location; and
- Though a gradual process of loss of wood fibre and loss of fibre strength, the strength of the pole decreases until it reaches the point where it no longer satisfies required safety factors under worst case conditions. At this point, inspections and/or testing will identify the need to replace this pole.

Like many other types of distribution assets, distribution poles are expected to last for a long time. A service life of 50 years is expected and when used under typical conditions, the maintenance free Mean Time Between Failures ("MTBF") is in the order of 400,000 hours.

It should be noted that the actual mean service life of utility poles is usually less than 50 years, as many are removed or upgraded due to such factors as road realignments or a need to upgrade to a taller or stronger pole as part of a distribution line upgrade.

Individually, the replacement value of these assets range from $1,000 to over $15,000. Maritime Electric has roughly 145,000 poles in service.

Because of the high MTBF value, relatively low installed cost, and large installed base of poles, it would be extremely impractical or impossible to closely monitor and maintain each pole in the same fashion as a substation steel structure, and the expense of such a program would far exceed its utility.

Instead, Maritime Electric manages its pole assets through a combination of:

- Industry standard purchasing specifications;

- Review of manufacturer's' quality assurance ("QA") and quality control ("QC") efforts;
- Inspection of new distribution poles as they are received;
- Periodic inspection and testing of poles while they are retained in stores as spares;
- In-situ inspections and periodic testing of poles whenever they are installed and/or visited during fieldwork; and
- Intake inspection whenever a previously used pole is returned to storage from the field. Occasionally, a pole in near perfect condition is reissued to the field.

7.3 Distribution Transformers

Defining Asset Condition

Like many other types of distribution assets, distribution transformers are expected to last for 40 years under typical conditions. The maintenance free MTBF of a distribution transformer is in the order of 300,000 hours. Individually, the replacement value of these assets range from $2,000 to over $53,000. Maritime Electric has roughly 38,000 in-service transformers.

Because of the high MTBF value, relatively low cost, and large installed base of distribution transformers, it would be extremely impractical or impossible to closely monitor and maintain each transformer in the same fashion as a substation power transformer, and the expense of such a program would far exceed its utility.

Instead, Maritime Electric manages its distribution transformer assets through a combination of:

- Industry standard purchasing specifications;
- Review of manufacturer's QA and QC efforts;
- Examination of the manufacturer's technical drawings and data for each distribution transformer order placed;
- Inspection and testing of new distribution transformer as they are received;
- Periodic inspection and technical testing of distribution transformers while they are retained in Maritime Electric's Stores department as spares;

- In-situ inspections and monitoring of transformers whenever they are installed and/or visited during fieldwork;
- Inspection whenever a previously used distribution transformer is returned to storage from the field. This is particularly important if the distribution transformer was removed from service because it is suspected to be not in good working order; and
- Exceptional programs may be initiated if an unforeseen issue arises. For example, the entire Maritime Electric inventory was tested for Polychlorinated Biphenyl (PCB) content in the mid-1980's once concerns were raised about environmental issues associated with these chemicals.

Maritime Electric has transitioned to using more efficient amorphous core transformers for polemount and padmount units. There are two types of losses associated with each transformer in the system; no-load losses and load losses. The no-load loss on a transformer is the energy used to keep the transformer energized with little or no load and the load loss is the energy required when the transformer is under load. Typically, a transformer is not fully loaded 100 per cent of the time so both of these factors affect the amount of energy required to operate a transformer. The amorphous core transformers have a core made of amorphous metal which significantly reduces the no-load losses. With this improved efficiency, the system's power factor will improve and less current flow is required to energize the transformer resulting in lower demand and energy costs. Amorphous core transformers are more expensive than traditional crystalline core transformers; however, the increased cost is more than offset by the savings received from lower system losses over the life of the transformer.

<u>In-Situ Testing of Pre-1982 Distribution Transformers for PCB</u>

In 2019, Maritime Electric engaged Emera Utility Services ("EUS") to carry out live testing of in-service polemount transformers what were manufactured prior to 1982 ("pre-1982"), to determine if the transformer oil contained PCB compounds.

The testing was required for Maritime Electric to be able to ensure that all equipment with PCB concentrations equal to or greater than 50 parts per million ("PPM" or "mg/kg") is removed from service before December 31, 2025, as required by Federal regulation.

In total, 2,571 pre-1982 polemount transformers were tested by EUS with the results provided in Table 5 below.

Table 5 Pre-1982 Transformer In-Situ PCB Testing Results		
PCB In-Situ Live Transformer Sample Results	**Count**	**Percentage**
<2 mg/kg PCB	2135	83%
≥2 to <50 mg/kg PCB	340	13%
≥50mg/kg PCB	46	2%
Transformers Retired	50	2%
Total	**2571**	**100%**

Upon completion of the sampling and testing program, all of the pre-1982 polemount transformers with a PCB concentration greater than 50mg/kg were removed from service and sent to an approved PCB disposal site. Some of the larger transformers with PCB concentrations less than 50mg/kg were also retired.

7.4 Other Distribution Assets

For other types of distribution assets, Maritime Electric uses good utility practice to anticipate when they are nearing the end of their useful life and endeavors to replace them before they fail.

In the event of a premature or other failure of an asset or asset component, Maritime Electric uses well established and industry-typical emergency response procedures to replace them in a timely and cost effective manner.

8.0 ASSET REPLACEMENT PROGRAM

Maritime Electric uses a variety of tools and methods to develop and monitor the Company's detailed budgets, which include both capital and operating/maintenance items.

8.1 Recent Historical Replacement Rates

Distribution Transformers

Maritime Electric has approximately 36,800 distribution polemount transformers in service. With an expected transformer life of 40 years, an average replacement rate of 920 transformers/year is required in order to achieve a sustainable average transformer age and condition.

Table 6 below shows the number of distribution polemount transformers replaced in each of the last five years[4].

Table 6 Distribution Polemount Transformers Replaced 2016 to 2020	
Year	**Transformers Replaced**
2016	636
2017	474
2018	867
2019	1,093
2020	575

A program to optimize distribution transformer installations has been developed to reduce the number of transformers installed. The program involves installing a larger sized polemount transformer in locations where successive groups of poles have distribution transformers mounted upon them. The larger polemounts will serve all customers in the area and the multiple smaller transformers will be removed. This program will optimize the number of distribution transformers to be managed and the system capacity of distribution transformers in the field.

Poles

Maritime Electric has approximately 145,000 distribution poles in service with approximately 18,000 being joint use poles owned by Bell Canada. The Company therefore owns approximately 127,000 distribution poles. With an expected distribution

4 For poletop transformers, asset retirement data was used for estimating annual replacement rates.

pole service life of 50 years, an average replacement rate of 2,540 Company owned poles/year is required in order to achieve a sustainable average pole age and condition.

Table 7 below shows the number of distribution poles replaced in each of the last five years[5].

Table 7 Distribution Poles Replaced 2016 to 2020	
Year	**Poles Replaced**
2016	910
2017	1,710
2018	2,482
2019	3,742
2020	2,442

The vast majority of eastern cedar poles in the Company's distribution system are over 40 years of age. In the past, these poles were being replaced through a combination of rebuild projects and storm events at a combined rate of approximately 900 per year. With the addition of the Eastern Cedar Pole Replacement Program in 2019, the target replacement rate was increased to approximately 1,500 poles per year. This reduced the timeframe for substantial removal of all eastern cedar distribution poles to approximately 10 years. Table 8 shows the number of eastern cedar poles remaining in the distribution system.

Table 8 Eastern Cedar Poles in Maritime Electric Distribution System	
Year End	**Eastern Cedar Poles Remaining**
2018	15,980
2019	12,471[6]
2020	11,020

8.2 Recent Historical and Future Capital Expenditures

Actual gross spending on Maritime Electric's distribution assets over the years 2016 to 2020 is shown in Figure 49 along with forecast spending for the years 2021 to 2025. This includes all spending on items such as replacement of assets due to storms, replacement

5 For distribution poles, asset retirement data was used for estimating annual replacement rates.

6 In addition to the poles replaced through the Eastern Cedar Pole Replacement Program in 2019, inspection identified 2,365 poles that were in the database as eastern cedar to be of a different type; as such, they were removed from the eastern cedar poles remaining count.

of assets due to government transportation infrastructure projects, streetlight work, installation of transformers, new services, installation of distribution equipment, metering tools and equipment, transportation equipment, line upgrades and line extensions. It is noted that these numbers are gross investments and do not show the offsetting effect of customer capital contributions. Examination of this data shows relatively stable capital spending on Maritime Electric's distribution system over the last five years (2016 to 2020). Over the next five years (2021 to 2025), Maritime Electric is adjusting its budget to increase capital spending on the distribution system to ensure targets for sustainable asset renewal can be achieved. The forecast budget increase for the next five years is driven largely by the PEI Broadband Project and a transition to smart meters.

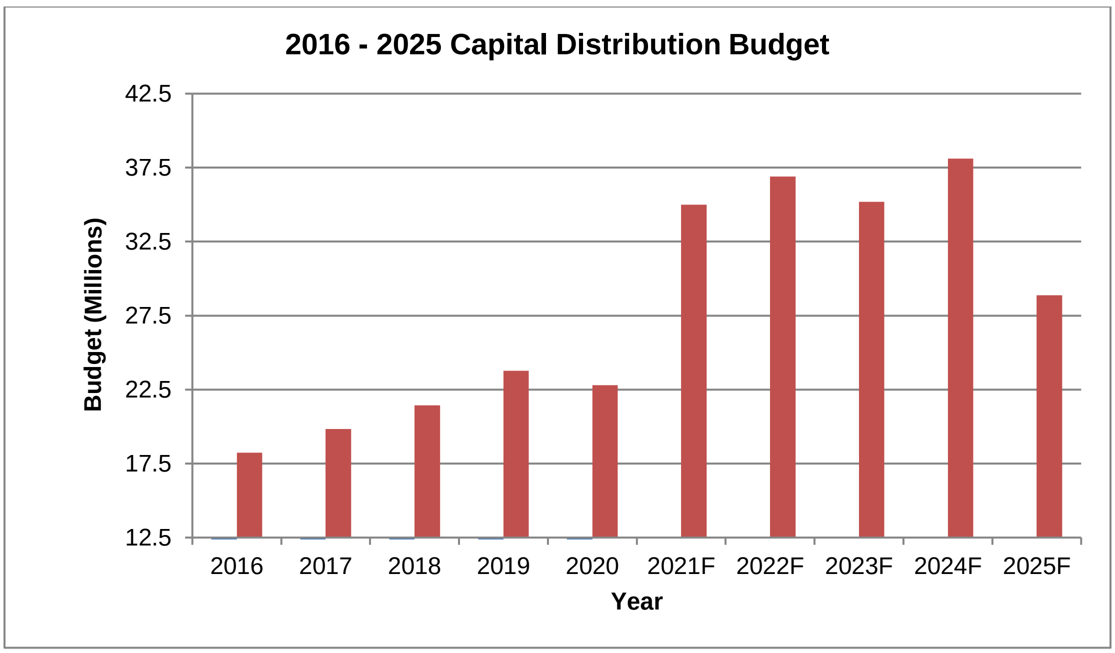

Figure 49: Annual/Forecast Capital Spending on Distribution System 2016 to 2025

8.3 Priorities for Budget Decision Making

The priority for budgeting is to provide a sustainable level of spending and resource deployment throughout the distribution system to accommodate safety improvements, planning for growth, improved system performance and reliability, renewal of deteriorated assets, customer growth needs, short and long term system planning needs and overall asset life cycle costs.

These factors must be continuously balanced while seeking to avoid undesirable customer rate shocks that can be triggered by large changes in annual revenue requirements when capital spending varies considerably from year to year.

Asset Replacement Planning Strategy

In planning for distribution asset replacement, Maritime Electric prioritizes projects as follows:

Priority Projects

Many capital expenditures are considered priority due to the nature and obligations of owning and operating an electric utility. Efforts must be made to ensure that these projects are performed in an efficient, cost effective and sustainable manner, both in the short term and over the long term.

Examples of priority projects include:

- Replacement of damaged transformers;
- Distribution line expansions and enhancements triggered by new customers and customers with increased loads;
- Projects triggered by external regulatory programs;
- Poles struck by vehicles;
- Unanticipated failure of a major substation component; and
- Retirement of PCB contaminated assets.

Non-Priority Projects

Some of the priority projects occur with enough regularity that statistical methods can be applied to roughly predict future expenditures. An example of this would be the capital spending on system expansions associated with the connection of new residential customers. Resources must be set aside in the budget forecast to allow for such projects.

Once the needs of these priority projects are addressed in the budget, non-priority projects are planned with a goal of smoothing out the year to year spending to allow for efficient resource scheduling.

Some expenditures can be deferred for one or more budget years. An example would be the replacement of distribution lines that have been in service for many years and are nearing the end of their useful life.

Note that these non-priority projects can only be deferred in the short term. Some of these may be deferred for one or more years, but will still need to be done sooner rather than later. The need to achieve optimum levels of re-investment has to be balanced against the need to manage the overall risks associated with such deferrals.

Since new non-priority projects will inevitably be identified in the future, it is essential to ensure that sufficient resources are allocated to avoid a long term build up or 'backlog' of such projects. This would result in a DAMP that is not achieving its sustainable goals.

When determining the order in which non-priority projects will be scheduled, the following factors will be considered:

- Severity of problem(s) or importance of the need for the project and the impact of project deferral;
- Impact on corporate risk when a project is scheduled/deferred;
- Impact on uncommitted budget (and therefore revenue requirement/future rate stability);
- Impact on future reliability improvements (e.g., a new distribution substation component may benefit more customers than a pole line rebuild, even though they cost the same to replace);
- Stakeholder requirements (e.g., customers, municipalities, regulators, etc.);
- Availability of internal and external resources; and
- Opportunities to achieve economies of scale by performing fewer, larger projects.

8.4 Dynamic Nature of Capital Priority Planning

It should be noted that this is a 'living or evolving' document that will be changed and adjusted as new information becomes available to Maritime Electric. It is based on best practices applied to presently known data. As new issues arise and new data becomes available, Maritime Electric expects to review this DAMP on a timely basis and make any necessary adjustments.

Examples of issues which would likely trigger such an adjustment include:

- One or more large industrial customers committing to construction in Maritime Electric's service territory;
- Large scale customer adoption of new technology, such as electric heat or electric vehicles; and/or
- Large scale solar and wind generation integration.

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I N T E R R O G A T O R I E S

IR-4 – Attachment 1

List of Future Capital Projects

Legend of Abbreviations – Future Capital Projects List	
Abbreviation	**Description**
A/C	Air Conditioning
AMI	Advanced Metering Infrastructure
ATV	All-Terrain Vehicle
BCC	Backup Control Centre
BGS	Borden Generating Station
CIS	Customer Information System
CGS	Charlottetown Generating Station
CSUP	Customer Service Utility Person
CT1	Combustion Turbine #1
CT2	Combustion Turbine #2
CT3	Combustion Turbine #3
ECC	Energy Control Centre
EIA	Environmental Impact Assessment
GIS	Geographic Information System
HMI	Human-Machine Interface
HVAC	Heating, Ventilation and Air Conditioning
IT	Information Technology
MDM/R	Meter Data Management and Repository
OT	Operations Technology
RO-EDI	Reverse Osmosis-Electrodeionization
SCADA	Supervisory Control and Data Acquisition
WRSC	West Royalty Service Centre
XFMR	Transformer

List of Future Capital Projects						
	2022	**2023**	**2024**	**2025**	**2026**	**Future**
	4.1 - Charlottetown Plant Buildings and Services Projects	**4.1 - Charlottetown Plant Buildings and Services Projects**	**4.1 - Charlottetown Plant Buildings and Services Projects**	**4.1 - Charlottetown Plant Buildings and Services Projects**	**4.1 - Charlottetown Plant Buildings and Services Projects**	**4.1 - Charlottetown Plant Buildings and Services Projects**
	ECC and BCC Miscellaneous Building Upgrades	ECC and BCC Miscellaneous Building Upgrades	ECC and BCC Miscellaneous Building Upgrades	ECC and BCC Miscellaneous Building Upgrades	ECC and BCC Miscellaneous Building Upgrades	ECC and BCC Miscellaneous Building Upgrades
	ECC - Hydronic Heating System Upgrades	ECC - Replace Rooftop A/C with Heat Pump	ECC - Window Replacement	ECC - Add GIS Capabilities to SCADA	ECC - Building Electrical Service Entrance Upgrade	ECC - SCADA Simulator
		ECC - Control Room Phone System with Wireless Headsets	ECC - SCADA Video Wall Display			CGS - Construction of New Entrance from Water Street Parkway
		CGS - Post Demolition Water Control (consultant)	ECC - Solar Panel and Powerwall Installation			CGS - Implementation of Heating System in Grey Shed
		CGS - Site Improvements and Landscaping	ECC - New ECC Operator Locker Room			CGS - Install Lunchroom and Washroom Facilities in Machine Shop
			CGS - Grey Storage Shed Renovations			CGS - Welding Area in the Grey Shed or Machine Shop
			CGS - Machine Shop Building Upgrades			CGS - Richmond Street Paving Upgrades
			CGS - Paving for Fuel Offloading and Steam Plant Lot			
	4.2 - Charlottetown Plant Turbine-Generator Projects	**4.2 - Charlottetown Plant Turbine-Generator Projects**	**4.2 - Charlottetown Plant Turbine-Generator Projects**	**4.2 - Charlottetown Plant Turbine-Generator Projects**	**4.2 - Charlottetown Plant Turbine-Generator Projects**	**4.2 - Charlottetown Plant Turbine-Generator Projects**
	Combustion Turbine Improvements, Parts and Tools	Combustion Turbine Improvements, Parts and Tools	Combustion Turbine Improvements, Parts and Tools	Combustion Turbine Improvements, Parts and Tools	Combustion Turbine Improvements, Parts and Tools	Combustion Turbine Improvements, Parts and Tools
	Installation of Electronic Fuel Tank Level Gauges	Flammables Storage Container for Lube Oil Storage	Additional 2,000,000 L Fuel Tank for CT3 Phase 1	Additional 2,000,000 L Fuel Tank for CT3 Phase 2	CT3 Hybrid Battery System Retrofit	Portable HMIs
		Install Ion Meters for Monthly Readings of Siemens Switchgear	Fire Detection Installation in CT3 Fuel Building	Coating of CT3 Fuel Tank and Three Borden Fuel Tanks	Install Salvaged Vibration Equipment on CT3 Auxillary Equipmen	New Parts Storage Facility
		Modify RO-EDI for Recirculation Flushing				Installation of Wet Supression System for CT3
4.0 - GENERATION		RO-EDI Equipment Upgrades				Installation of Bird Deterrent Equipment
		Generation Capacity Upgrade Study				Electronic Data Consolidation Equipment
						Replace Dorman Diesel
						New Diesel Pipeline Interconnection
	4.3 - Borden Plant Projects	**4.3 - Borden Plant Projects**	**4.3 - Borden Plant Projects**	**4.3 - Borden Plant Projects**	**4.3 - Borden Plant Projects**	**4.3 - Borden Plant Projects**
	BGS Improvements, Parts and Tools	BGS Improvements, Parts and Tools	BGS Improvements, Parts and Tools	BGS Improvements, Parts and Tools	BGS Improvements, Parts and Tools	BGS Improvements, Parts and Tools
	Installation of Commercial Storage Containers	Installation of Wireless Internet and Intranet Access	CT2 Generator Inspection/Overhaul	CT2 Battery Replacements	CT1 Main Unit Gearbox Inspection and Refurbishment	City Water Hookup and Fire Hydrant/Monitor Installation
	Borden Building Upgrades	CT1 Generator Inspection/Overhaul			CT2 Sodium Filter Replacement	Installation of Solar Panels and Battery Storage
	Electrical Upgrades to Borden Facilities					Outbuildings Upgrades and/or Replacement
	Solar Panel and Powerwall Installation					Exhaust Volute on CT1
	CT1 and CT2 Life Extension Engineering Assessment					Renovate Air Filter House on CT2
	CT1 Stack Accessibility Improvements					CT2 Motor Control Centre Upgrades
	CT2 Battery Charger Replacement					
	CT2 Detroit Diesel Starter Overhaul					
	CT2 Stack Repairs					
	5.1 - Replacements Due to Storms and Road Alterations	**5.1 - Replacements Due to Storms and Road Alterations**	**5.1 - Replacements Due to Storms and Road Alterations**	**5.1 - Replacements Due to Storms and Road Alterations**	**5.1 - Replacements Due to Storms and Road Alterations**	**5.1 - Replacements Due to Storms and Road Alterations**
	Replacements Due to Storms	Replacements Due to Storms	Replacements Due to Storms	Replacements Due to Storms	Replacements Due to Storms	Replacements Due to Storms
	Replacements Due to Road Alterations	Replacements Due to Road Alterations	Replacements Due to Road Alterations	Replacements Due to Road Alterations	Replacements Due to Road Alterations	Replacements Due to Road Alterations
	5.2 - Distribution Transformers	**5.2 - Distribution Transformers**	**5.2 - Distribution Transformers**	**5.2 - Distribution Transformers**	**5.2 - Distribution Transformers**	**5.2 - Distribution Transformers**
	Polemount and Padmount Transformers	Polemount and Padmount Transformers	Polemount and Padmount Transformers	Polemount and Padmount Transformers	Polemount and Padmount Transformers	Polemount and Padmount Transformers
	Spill Prevention Program	Spill Prevention Program	Spill Prevention Program	Spill Prevention Program	Spill Prevention Program	Spill Prevention Program
	5.3 - Services and Street Lighting	**5.3 - Services and Street Lighting**	**5.3 - Services and Street Lighting**	**5.3 - Services and Street Lighting**	**5.3 - Services and Street Lighting**	**5.3 - Services and Street Lighting**
	Services	Services	Services	Services	Services	Services
	Street Lighting	Street Lighting	Street Lighting	Street Lighting	Street Lighting	Street Lighting
	5.4 - Line Extensions	**5.4 - Line Extensions**	**5.4 - Line Extensions**	**5.4 - Line Extensions**	**5.4 - Line Extensions**	**5.4 - Line Extensions**
	Customer Driven Line Extensions	Customer Driven Line Extensions	Customer Driven Line Extensions	Customer Driven Line Extensions	Customer Driven Line Extensions	Customer Driven Line Extensions
	Glen Drive 3-Phase Line Extension	Two Feeders from East Royalty Substation (tap existing)	Blue Shank Road to Rte 1A (3-phase conversion)	Cameron Road (white phase WR02560) 27-XFMR	Victoria Cross Voltage Conversion (VC01482)	Tie Souris & Dingwells Mills (across the bridge)
	Bunbury to Mt. Albion Tie Line Extension	3rd Feeder from East Royalty Substation (double circuit)	Blue Shank Road KN80084 (3-phase conversion)	New Albany Feeder	New Dover Feeder	Wellington Feeder
			Lady Slipper Drive SE23313 (3-phase conversion)	Canoe Cove Voltage Conversion (blue phase WR15100) 143-XFMR		Souris Backup from Dingwells Mills (c/w automated switch)
			Riverdale Road (3-phase conversion/step downs/85-XFMR)			New Kensington Feeder
			Robertson Road (3 phase conversion)			Eldon-Belfast Voltage Conversion
	5.5 - Line Rebuilds	**5.5 - Line Rebuilds**	**5.5 - Line Rebuilds**	**5.5 - Line Rebuilds**	**5.5 - Line Rebuilds**	**5.5 - Line Rebuilds**
	Broadband Fibre Year 3	Broadband Fibre Year 4	Miscellaneous Communication Make-Ready Projects	Miscellaneous Communication Make-Ready Projects	Miscellaneous Communication Make-Ready Projects	Miscellaneous Communication Make-Ready Projects
	Northside Road Single Phase Rebuild	West Royalty Industrial Park Backlot Feed Upgrade	Village Green Road	Northside Road	Rte 20 Malpeque	Kinross to Vernon River
	Rustico Road Rebuild and Voltage Conversion	Rte 2 Elmsdale to Bloomfield	Grahams Road (RT01072)	Keppoch Road	Baltic Road	Mount Edward Road
5.0 - DISTRIBUTION	Kingston Road Rebuild	Crossroad Substation Distribution Work	Alberton to Elmsdale	Egmont Bay Rte #11 Maximeville (WL02028)	Egmont Bay	TCH Desable to Victoria
	North York Voltage Conversion	Distribution Line Refurbishment Program	Distribution Line Refurbishment Program	North York Rebuild	New Zealand Road-West	Kingston Voltage Conversion
	Distribution Line Refurbishment Program	Porcelain Cutout Replacement Program	Porcelain Cutout Replacement Program	Distribution Line Refurbishment Program	TCH Mt Mellick to Rte 3	Backup Rattenbury with Kensington
	Porcelain Cutout Replacement Program	Eastern Cedar Replacement Program	Eastern Cedar Replacement Program	Porcelain Cutout Replacement Program	Fernwood	Locke Road
	Eastern Cedar Replacement Program	Copper Wire Replacement Program	Copper Wire Replacement Program	Eastern Cedar Replacement Program	Distribution Line Refurbishment Program	St. Peters Road
		Backlot Feed Relocation Program	Backlot Feed Relocation Program	Copper Wire Replacement Program	Porcelain Cutout Replacement Program	Greenmount Road
				Backlot Feed Relocation Program	Eastern Cedar Replacement Program	Montrose to Tignish
					Copper Wire Replacement Program	West Cape to Howards Cove
					Backlot Feed Relocation Program	Lower Bedeque
						Baltic Road-East
						Green Road Bonshaw (rebuild/voltage upgrade)
						Spring Park Road/Douglas Street
						Nodd Road
						Distribution Line Refurbishment Program
						Porcelain Cutout Replacement Program
						Eastern Cedar Replacement Program
						Copper Wire Replacement Program
						Backlot Feed Relocation Program

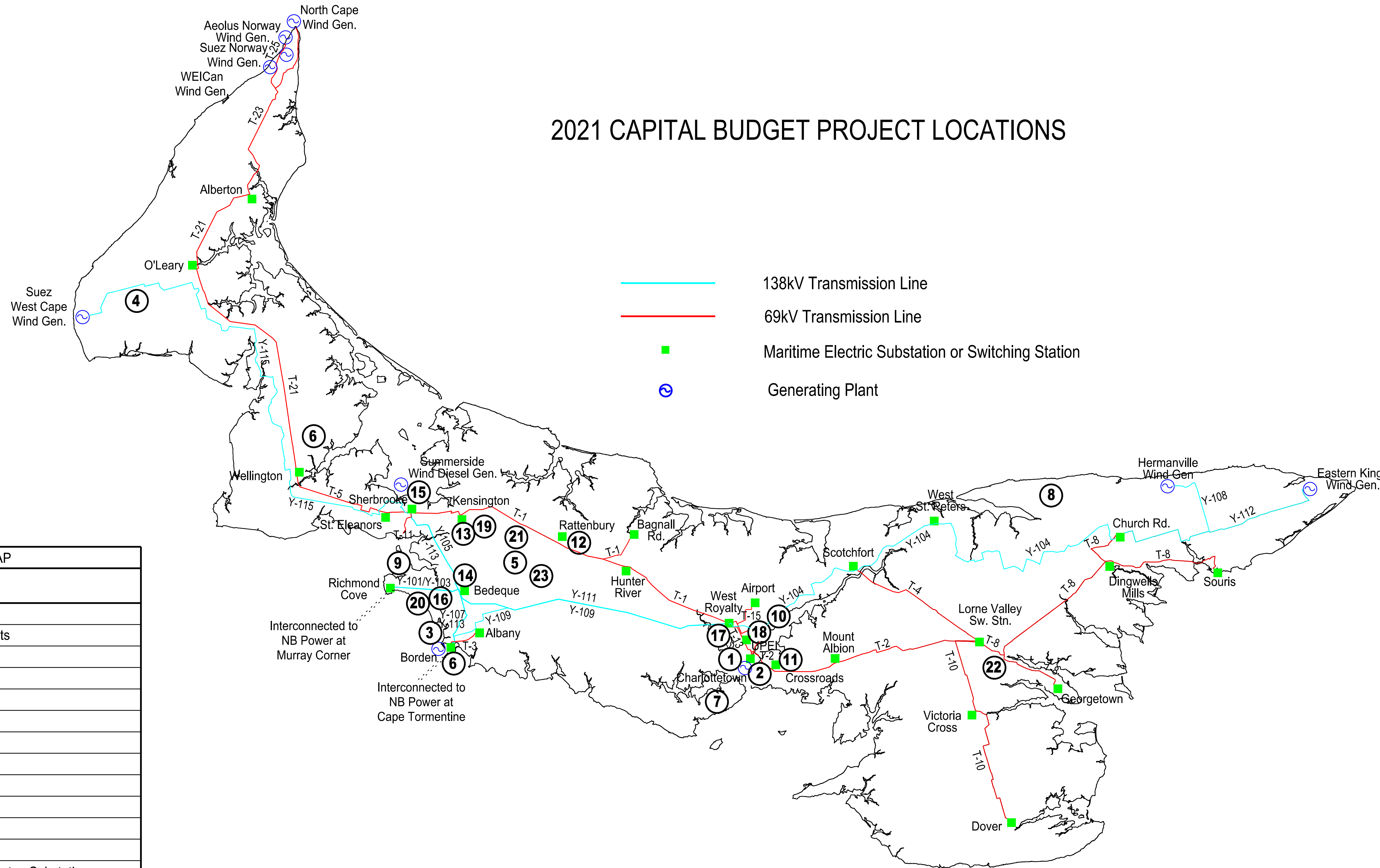
List of Future Capital Projects						
	2022	**2023**	**2024**	**2025**	**2026**	**Future**
	5.6 - System Meters	**5.6 - System Meters**	**5.6 - System Meters**	**5.6 - System Meters**	**5.6 - System Meters**	**5.6 - System Meters**
	Watt-Hour Meters	Watt-Hour Meters	Watt-Hour Meters	Watt-Hour Meters	Watt-Hour Meters	Watt-Hour Meters
	Combination Meters	Combination Meters	Combination Meters	Combination Meters	Combination Meters	Combination Meters
	Outdoor Metering Tanks	Outdoor Metering Tanks	Outdoor Metering Tanks	Outdoor Metering Tanks	Outdoor Metering Tanks	Outdoor Metering Tanks
	Miscellaneous Metering Equipment	Miscellaneous Metering Equipment	Miscellaneous Metering Equipment	Miscellaneous Metering Equipment	Miscellaneous Metering Equipment	Miscellaneous Metering Equipment
	Smart Meters (AMI)	Smart Meters (AMI)	Smart Meters (AMI)	Smart Meters (AMI)	Smart Meters (AMI)	Smart Meters (AMI)
	5.7 - Distribution Equipment	**5.7 - Distribution Equipment**	**5.7 - Distribution Equipment**	**5.7 - Distribution Equipment**	**5.7 - Distribution Equipment**	**5.7 - Distribution Equipment**
5.0 - DISTRIBUTION	Distribution, SCADA and Communications Equipment	Distribution, SCADA and Communications Equipment	Distribution, SCADA and Communications Equipment	Distribution, SCADA and Communications Equipment	Distribution, SCADA and Communications Equipment	Distribution, SCADA and Communications Equipment
	Metering Equipment	Metering Equipment	Metering Equipment	Metering Equipment	Metering Equipment	Metering Equipment
	Line Tools and Equipment	Line Tools and Equipment	Line Tools and Equipment	Line Tools and Equipment	Line Tools and Equipment	Line Tools and Equipment
	5.8 - Transportation Equipment	**5.8 - Transportation Equipment**	**5.8 - Transportation Equipment**	**5.8 - Transportation Equipment**	**5.8 - Transportation Equipment**	**5.8 - Transportation Equipment**
	Aerial Bucket with Elevator (Central)	Digger Derrick (Central)	Aerial Bucket (Central)	CSUP Truck	Aerial Bucket (East)	Line Trucks and Other Large Vehicles
	Tandem Digger (West)	Digger Derrick (Central)	Tracked Bucket	Tracked Digger	Digger Derrick (Central)	Offroad Vehicles
	CSUP Truck (Central)	CSUP Truck (West)	Large pulling Trailer	Telehandler (Stores)	CSUP Truck	Balance of Vehicles and Trailers
	Balance of Vehicles and Trailers	Jeep for Towing Mobile Transformer and Nodwells	Large Tensioning Trailer	Side by Side ATV with Trailer	Balance of Vehicles and Trailers	
		Balance of Vehicles and Trailers	Balance of Vehicles and Trailers	Balance of Vehicles and Trailers		
	6.1.- Substation Projects	**6.1.- Substation Projects**	**6.1.- Substation Projects**	**6.1.- Substation Projects**	**6.1.- Substation Projects**	**6.1.- Substation Projects**
	Substation Modernization	Substation Modernization	Substation Modernization	Substation Modernization	Substation Modernization	Substation Modernization
	138 kV Breaker Replacement Program	138 kV Breaker Replacement Program	138 kV Breaker Replacement Program	138 kV Breaker Replacement Program	138 kV Breaker Replacement Program	138 kV Breaker Replacement Program
	Substation Oil Containment	Substation Oil Containment	Substation Oil Containment	Substation Oil Containment	Substation Oil Containment	Substation Oil Containment
	Substation Master SCADA System Refresh	West Royalty Autotransformer Phase 2 (Y-109 bay; install X5)	West Royalty Autotransformer Phase 3 (tie-breaker)	69 kV Alberton Breaker Replacement	138 kV Spare Breaker	Tignish Power Transformer
	West Royalty Autotransformer Phase 1 (order X5)	Alberton Substation Low Voltage Bus and Control Building Phase 1	Alberton Substation - New Low Voltage Bus and Control Building Phase 2	69 kV Spare Breaker	West Royalty Autotransformer Phase 5 (install X6)	Tignish Substation Construction
	East Royalty Substation Transformer	Crossroads Substation Upgrade Phase 2 Construction	St. Eleanor's 10 MVA Power Transformer	West Royalty Autotransformer Phase 4 (order X6/install X6 cable)	Tignish Substation Land Purchase, EIA and Engineering	O'Leary Switching Station Phase 2
	East Royalty Substation Construction	Power Transformer Upgrade - Crossroads #61	X4 West Royalty 20 MVA Power Transformer	O'Leary Switching Station Engineering Design	O'Leary Switching Station Phase 1 Construction	Auto transformer O'Leary
	Crossroads Substation Upgrade Engineering Design	Communication Fibre Modifications	Reactor 1 Bedeque	O'Leary Switching Station Phase 1 Construction	Communication Fibre from Sherbrooke to O'Leary	69 kV Mobile Replace #47
	Crossroads Substation Upgrade Phase 1 Construction	Communication Fibre Lorne Valley to Georgetown	Communication Fibre Modifications	Sherbrooke Switching Station Upgrade Engineering	O'Leary Autotransformer Specification	Borden X3
	Power Transformer Upgrade - Crossroads #66	Communication Fibre Lorne Valley to Victoria Cross	Communication Fibre Lorne Valley to Dingwells Mills	Sherbrooke Switching Station Tie Breaker	X1 Sherbrooke Replacement	Communication Fibre Expansion
	Cavendish Feeder Automation		Communication Fibre Borden to Albany	X1 West Royalty 20 MVA Power Transformer	69 kV Mobile Transformer #47 Replacement	Communication Fibre Modifications
	Mobile Communications Upgrade			Reactor 2 Bedeque	Communication System Upgrade (Refresh)	Cavendish Substation
	Communication Fibre Modifications			Communication System Upgrade	Communication Fibre Expansion	Bedeque Substation
	Communication Fibre Church Road to Souris			Communication Fibre Modifications	Communication Fibre Modifications	Scotchfort Substation
				Communication Fibre Victoria Cross to Dover		Mt. Pleasant Substation
				Communication Fibre Bedeque to Richmond Cove		Charlottetown Area Substation
	6.2 - Transmission Projects	**6.2 - Transmission Projects**	**6.2 - Transmission Projects**	**6.2 - Transmission Projects**	**6.2 - Transmission Projects**	**6.2 - Transmission Projects**
6.0 - TRANSMISSION	T-11 Rebuild	Transmission Lines Aerial Inspection	69 Kv and 138 Kv Switch Inspection and Repair Program	Looped Transmission Feed to O'Leary (69 kV)	Reroute T-1 out of Thorndale Drive Area	Y-101 Rebuild Part 2
	Transmission Tap East Royalty Substation	69 kV and 138 kV Switch Inspection and Repair Program	Transmission Line Refurbishment Program	Transmission Lines Aerial Inspection	O'Leary Switching Station 138 kV Transmission Work	T-15 Rebuild
	Crossroads Substation Upgrade Phase 1	Transmission Line Refurbishment Program		69 kV and 138 kV Switch Inspection and Repair Program	Y-101 Rebuild Part 1	Y-103 Rebuild
	West Royalty Substation Transmission Work			Transmission Line Refurbishment Program	69 kV and 138 kV Switch Inspection and Repair Program	Y-105 Rebuild
	69 kV and 138 kV Switch Inspection and Repair Program				Transmission Line Refurbishment Program	Y-107 Rebuild
	Transmission Line Refurbishment Program					T-1 Re-route Hunter River to St. Patrick's Road
						T-1 Re-route Rattenbury to Kensington
						Rebuild (in place) Y-109 from the Connolly Woods Road to Bedeque
						Rebuild Y-109 from Connelly Woods Road to the Bannockburn Road
						Mount Pleasant Transmission
						Rebuild Y-111 from Towers to Bedeque
						Looped Transmission Feed to Victoria Cross (T-10)
						Looped Transmission Feed to Georgetown Substation
						Rebuild Georgetown Substation
						Y-110 from Scotchfort to Lorne Valley
						Lorne Valley Expansion
						Y-119 from Bannockburn Road to Scotchfort
	7.1 Corporate Services	**7.1 Corporate Services**	**7.1 Corporate Services**	**7.1 Corporate Services**	**7.1 Corporate Services**	**7.1 Corporate Services**
	Recurring Facilities Upgrade Projects	Recurring Facilities Upgrade Projects	Recurring Facilities Upgrade Projects	Recurring Facilities Upgrade Projects	Recurring Facilities Upgrade Projects	Recurring Facilities Upgrade Projects
	180 Kent Roof Replacement	180 Kent HVAC, Insulation, Electrical	WRSC Improvement Plan Phase 3			
	7.2 Information Technology	**7.2 Information Technology**	**7.2 Information Technology**	**7.2 Information Technology**	**7.2 Information Technology**	**7.2 Information Technology**
	Hardware Acquisitions	Hardware Acquisitions	Hardware Acquisitions	Hardware Acquisitions	Hardware Acquisitions	Hardware Acquisitions
	Purchased Software Upgrades	Purchased Software Upgrades	Purchased Software Upgrades	Purchased Software Upgrades	Purchased Software Upgrades	Purchased Software Upgrades
	MDM/R-CIS-Billing Year 1	MDM/R-CIS-Billing Year 2	MDM/R-CIS-Billing Year 3	Online Services	Online Services	Online Services
7.0 - CORPORATE	Online Services	Online Services	Online Services	Cybersecurity IT	Cybersecurity IT	Cybersecurity IT
	Cybersecurity IT	Cybersecurity IT	Cybersecurity IT	Security Review	Security Review	Security Review
	Security Review	Security Review	Security Review	OT Cyber Projects	OT Cyber Projects	OT Cyber Projects
	OT Cyber Projects	OT Cyber Projects	OT Cyber Projects	Other IT Projects	Other IT Projects	Other IT Projects
	Load Flow Software	Load Flow Software	Load Modeling Software			
	Umbraco Web Hosting	Engineering Fixed Assets	Other IT Projects			
	Survey Diagram Software	Other IT Projects				
	Substation Refresh OT					

I N T E R R O G A T O R I E S

IR-7 – Attachment 1

2021 Capital Budget Projects Locations

2021 CAPITAL BUDGET PROJECT LOCATIONS



LEGEND OF PROJECT LOCATIONS ON MAP		
Map Location	Budget Category	Project Description
1	4.1	Energy Control Centre Upgrades
2	4.2	Charlottetown Plant Turbine-Generator Projects
3	4.3	Borden Plant Projects
4	5.4b	Smallman Road Line Extension
5	5.5a(i)	Kinkora - Route 225 Line Rebuild
6	5.5a(ii)	Lot 16 - Route 12 Line Rebuild
7	5.5a(iii)	Rocky Point Line Rebuild
8	5.5a(iv)	Cable Head East Line Rebuild
9	5.5a(v)	Searletown - Route 10 Line Rebuild
10	6.1a	East Royalty Substation
11	6.1b	Crossroads Substation Modifications
12	6.1c	Rattenbury Transformer Upgrade
13	6.1d	Substation Oil Containment Program - Kensington Substation
14	6.1e(i)	Ground Grid Modernization - Bedeque Substation
15	6.1e(i)	Ground Grid Modernization - Sherbrooke Substation
16	6.1e(ii)	Substation Security Camera Installation - Bedeque Substation
17	6.1e(iv)	Substation and Distribution Automation - West Royalty to Clyde River
18	6.1e(v)	Substation Backup Generator System - West Royalty Substation
19	6.1e(vi)	Mobile Transformer Accomodation - Kensington Substation
20	6.1f	138kV Breaker Replacement Program - Bedeque Substation
21	6.1h	Fibre Communication - Sherbrooke to Bagnall Road
22	6.2a	69kV and 138kV Switch Program - T-8 (Cardigan area)
23	6.2c	Y-119 Transmission Line - Mount Tryon to Bannockburn Road

MARITIME ELECTRIC
ENERGY SUPPLY SYSTEM
PRINCE EDWARD ISLAND

I N T E R R O G A T O R I E S

IR-9 – Attachment 1

Procedure:
850229 - Use of Motor Vehicles on Company Business

MARITIME ELECTRIC A FORTIS COMPANY Corporate Procedure	**Title: Use of Motor Vehicles on Company Business** **Procedure No.: 850229** **Page: 1 of 4**

Date Issued:	December 11, 2014	Prepared By:	Anne MacAulay
Date Revised:		Revised By:	
Approved by:	Anne MacAulay Manager, Human Resources		Steve Loggie Vice President, Finance and Chief Financial Officer

Hazard Identification Number(s):	
Process Area/Department:	✓ Office ✓ Metering ✓ Stores ✓ Substations ✓ Line & Forestry ✓ Facilities ✓ Generation

PURPOSE

Maritime Electric Company, Limited ("the Company") is implementing this policy to ensure that individuals operating motor vehicles in the course of the Company's business are properly licensed, insured and authorized to operate these vehicles.

SCOPE

This policy applies to employees operating Company or private vehicles in the course of their duties.

PROCEDURES AND FORMS

Safety Manual (Procedure #802020)
Reporting of Accident and Incidents (Procedure #802001)
Renewal of Drivers Licenses for Qualified Employees (Procedure #840320)
Mobile Communications (Procedure #850224)
Use of Company Vehicle Agreement (Form #850229A)
Proof of Valid Driver's License - Employee Consent Form (Part I) (Form #850229B)
Driver's Abstract - Employee Consent Form - Part 2 (Form #850229C)

PROCEDURES:

PART 1: DRIVER QUALIFICATIONS AND SAFE USE OF VEHICLES

1.1 Valid License as Condition of Employment

Before operating a Company owned, leased or rented vehicle or a personal vehicle for Company business an employee must:

- Hold a valid PEI Driver's license appropriate for the class of motor vehicle being driven for Company business.

1.2 Safe Use of Vehicles

All PEI Traffic Laws shall be complied with.

- Employees who operate a Company or personal vehicle in the course of their duties must be aware of, understand and comply with the transportation standards as outlined in the Company Safety Manual - Section 9.

- Superintendents/Supervisors must regularly assess job functions to determine if specific driver training is required. Factors to consider in the assessment include an evaluation of such things as an increase or decrease in kilometers driven and any change in risk within the job function but are not limited to these influences. Such driver training is to be included in the training database.

- Employees may use Company vehicles only when conducting Company business. Further, no employee is permitted to transport in a Company vehicle any family member, friend or other non-employee of the Company unless it is a contractor hired by the Company. A vehicle that is part of a compensation package is exempt from these restrictions

- Employees are responsible to notify their Supervisor of any incidents involving the use of Company or personal vehicles during the course of their work (Reporting Accident and Incidents - Procedure #802001).

- Drivers are responsible for any traffic violations and tickets issued to them while operating a Company vehicle or while operating their personal vehicle for Company business.

- The requirement to be in possession of a valid driver's license is a condition of employment for many employees of the Company. Any loss or restriction of driving privileges that restricts an employee's ability to properly perform his/her job will be reviewed. In all such cases, the employee shall immediately notify his/her immediate Supervisor or Manager. The Supervisor and/or Manager will consult with Human Resources to assess the overall impact on the employee's ability to perform regular duties and identify any appropriate action to be taken.

- Employees must sign a Use of Company Vehicle Form (Form #850229A) and provide a copy of their current PEI Driver's License to Human Resources before being permitted to drive a Company vehicle or a private vehicle for Company business.

1.3 <u>Driver's Abstract (Driving Record) and License</u>

Employees whose positions make holding a valid driver's license a condition of employment will be required to provide their on-going consent for the Company to obtain a copy of their driving records from the Highway Safety Division when and as required by the Company. Costs related to provision of driving abstracts shall be the responsibility of the Company. The Company will review the information provided to ensure the employee has both a valid driver's license and a safe driving record. The Company has a responsibility to ensure that any employee who operates its vehicles possesses both of these requirements. An employee who refuses to provide consent will be required to obtain their driver's abstract at their own cost and provide it to the Company within a reasonable time frame to be established by the Company.

1.4 Driving Record
For purposes of this policy, a driving infraction will be included for consideration whether or not it occurred when the employee was engaged in the course of their employment. Infractions include all provincial or criminal driving offences or occurrences for which a driver may lose points on their driver's license. Whether or not a particular employee's driving record is considered to be unsafe will be determined by the employee's Manager in consultation with Human Resources and assessed on a case by case basis.

PART 2 NON-COMPANY OWNED MOTOR VEHICLES INSURANCE

2.1 Auto Insurance Coverage
An employee who uses their personal motor vehicle for Company business is responsible for ensuring that the vehicle is covered with the owner's insurance as required by law. If the use of an employee's personal vehicle on Company business extends beyond merely incidental use, it is the responsibility of the employee to notify the vehicle insurer of this fact and ensure adequate insurance coverage is maintained on the personal vehicle at all times.

2.2 Insurance
In the event of an accident claim, the employee's personal vehicle insurance pays first and the Company's insurance pays second to the extent of the policy. A claim paid by an employee's private insurance for an accident in which the employee operated their personal vehicle to conduct Company business is not reimbursable from Company funds or Company insurance.

2.3 Deductibles
Personal vehicle insurance deductibles are the responsibility of the employee and are not reimbursable by the Company.

PART 3: POLICY ADMINISTRATION

3.1 Administration
Responsibility for administration of this policy shall reside with the Human Resources Department. In administering this policy, Human Resources shall consult with supervisors, management personnel and the Health, Safety & Environment Section as appropriate.

PART 4: PRIVACY CONCERNS

4.1 The Company recognizes the need to balance its legal obligation to ensure only licensed and safe drivers operate vehicles engaged in work for the Company with the privacy interests of those operating such vehicles. An employee's driver's license or driver's abstract information is personal information under the province's Freedom of Information and Protection of Privacy Act, R.S.P.E.I. 1988, Cap. F-15.01. For this reason, employee consent is sought for the release of such information (Proof of Valid Driver's License - Employee Consent Form - Part 1 - Form #850229B and Driver Abstract - Employee Consent Form - Part 2 - Form #850229C).

The Company has a legal obligation to exercise due diligence in ensuring that no one operates a Company or a private vehicle in the performance of work for the Company unless that person is licensed and safe to operate the vehicle. Due diligence in this area requires that the Company not simply rely on out of date information or on assumptions that employees are licensed and safe. The Company must take active measures to ensure that this is indeed the case.

4.2 In order to meet its due diligence obligations and to protect employees' personal information, the Company makes the following commitments in relation to this employee personal information obtained under this policy:

- No more personal information than necessary will be collected.
- Personal information collected will be used only for the purposes outlined in this policy.
- An individual employee shall have the right to examine their personal information and make any correction needed should there be an error in the information.
- Personal information will be kept confidential and secure. Access shall be limited to the Human Resources Manager and the Human Resources Coordinator and, where necessary, to those members of management involved in assessing an employee's driving record in accordance with this policy.
- Personal information will be destroyed when no longer relevant or when replaced by more current information.

I N T E R R O G A T O R I E S

IR-9 – Attachment 2

Procedure:
800009 – Travel and Business Expenses

MARITIME ELECTRIC A FORTIS COMPANY **Corporate Procedure**	**Title: Travel and Business Expenses** **Procedure No.: 800009** **Page: 1 of 5**

Date Issued:	April 16, 2002	Prepared By:	K. A. Veldhuis/D. D. Auld
Date Revised:	February 10, 2017	Revised By:	Rolland Young
Approved by:	Jason Roberts Director, Regulatory and Financial Planning		Steve Loggie Vice President – Finance and Corporate Services and Chief Financial Officer

PURPOSE:
The Company shall pay all reasonable business related expenses incurred by employees who are required to travel or reside away from their normal residence on Company assignments/business. This policy shall also include reasonable expenses related to training/education.

It is intended that employees shall neither lose nor profit from business related expenses and that all arrangements with respect to transportation and accommodation be reasonable under the circumstances. Employees required to travel on behalf of the Company must receive prior approval from their Supervisor. All such expenses have to be claimed on expense reports or P-Card statements and must indicate the purpose or reason for the expenditure.

Executives and Managers may incur business entertainment expenses in connection with their duties provided such expenses are directly related to the Company's performance, profitability or business interests. All other employees of the Company must have prior permission from an Executive or Manager to incur business entertainment expenses.

SCOPE:
This policy and procedure shall apply to all employees.

REFERENCES:
Corporate Purchasing Card (P-Card) Program (Procedure #603003)
Approval Levels (Procedure #800003)
Personal Expense Account Form (Form #800009A)
Request for Cheque for Cash Advance (Form #800009B)
Employee Payment Information Form (Form #800009C)
Employee Training and Development – Part-Time Studies (Procedure #840801)
The Collective Agreement for bargaining unit employees (Procedure #840501 - Articles 20 and 38.80)

PROCEDURES:
1. <u>Reimbursement</u>
   To be reimbursed, the employee shall complete an Expense Report (Form #800009A) or complete the Purchasing Card statement and submit it to his/her Supervisor together with travel dates and appropriate receipts. Where the employee is submitting an expense report, all reimbursements will be made via electronic payment. If the employee has not previously done so, he/she must complete an Employee Payment Information Form (Form #800009C) to provide necessary banking details for electronic payment. The approver is responsible for reviewing the documentation for both reasonableness and adherence to this policy.

MARITIME ELECTRIC A FORTIS COMPANY	**Title: Travel and Business Expenses**
Corporate Procedure	**Procedure No.: 800009 Date Revised: February 10, 2017 Page: 2 of 5**

2. Authorization
Those who are authorized to approve expense accounts shall assess the reasonableness of the expenses claimed prior to approval.

3. Arrangements
Travel arrangements will be made by an Administrative Assistant. Where available the services of a designated travel agency shall be used.

Wherever possible all expenses should be paid by means of the Corporate P-Card. These cards can be obtained by contacting the Administrative Assistant (180 Kent Street – 4th Floor).

4. Advance
Employees who do not have a Corporate P-Card may request a cash advance through the Area Office with the approval of their Supervisor using Request for Cash Advance Form (Form #800009B). Requests for cash advances will be paid via electronic payment. If the employee has not previously done so, he/she must complete an Employee Payment Information Form (Form #800009C) to provide necessary banking details for electronic payment.

5. Transportation
The Company will provide employees with necessary transportation for completing the work assignment.

   a. Company Supplied Transportation: Wherever possible and practicable, Company vehicles will be used to provide transportation to work assignments.

   b. Employee's Vehicle: If it is the most economical and practical method, the employee's vehicle may be used in the performance of Company business and a mileage allowance rate will be paid at the rate established from time to time. An employee using his/her vehicle sufficiently to be classified under insurance for "business purposes' shall be reimbursed by the Company for the difference between normal insurance rates and those charged for "business purposes". The employee must obtain the approval of the Supervisor before incurring the expense. For bargaining unit employees, Article 38.80 may apply.

   c. Rented Vehicles: If required for reason of economy or efficiency, employees travelling out of town may rent a vehicle of the appropriate type. Employees should rent the vehicle using the Corporate Purchasing Card and insurance coverage on such rented vehicles should be declined.

   d. Taxis: May be used at the discretion of the traveller, but must be reasonable. Airport shuttle or bus services should be used where appropriate.

   e. Air Travel: Employees are expected to take all reasonable measures to minimize the cost of air travel. Employees are expected to utilize economy class fares. Where travel plans are known in advance and employees can take advantage of lower fares they are expected to do so. A Vice President may approve business class where appropriate.

If an employee wishes to be accompanied by a spouse or partner, the employee may choose to credit the cost of the economy ticket towards the cost of two lower cost tickets. The Company will pay a maximum of the cost of the economy ticket in these situations. Any costs, including hotel and meals, over and above the cost of the economy ticket must be borne by the employee. The employee must provide support for the cost of the economy ticket as part of their claim for reimbursement and all costs claimed associated with the revised arrangements must be supported by appropriate receipts. The Company limits the use of this option to once per calendar year.

If a business trip is cancelled after travel arrangements are made, an employee will not be reimbursed for any non-refundable ticket or tickets purchased to accommodate the travel of a spouse or partner.

6. <u>Accommodations</u>
When an employee is required to reside away from their normal residence, the Company will provide overnight accommodations. To the extent possible and appropriate, hotel accommodations should be arranged where the Company has a corporate rate or where prices are moderate.

7. <u>Meals</u>
Meal expenses incurred while an employee is **not travelling** on Company business will be paid only if incurred for the purpose of Company business. Expense reports and Corporate Card statements, supported by receipts, must indicate the purpose or nature of the business discussions and identify by name who was entertained.

Reasonable meal expenses are allowable if incurred while travelling for an overnight duration away from the employee's ordinary work place on Company business. If not travelling for an overnight duration, reasonable meal expenses are allowable if it is not possible or practical for an employee to make his/her normal lunch arrangements.

Employees may claim meal expenses by submitting meal receipts or by using a per diem meal allowance. The use of receipts or an allowance is the employee's option. A mix of both options may not be used to claim meal expenses for the same trip.

Under no circumstances should a per diem meal allowance be claimed for meals that were paid by others or for meals included in accommodation, conferences, or course fees, etc.

The maximum daily per diem meal allowance amounts are:

▪ Breakfast	$ 7.00	
▪ Lunch	11.50	
▪ Dinner	15.00	
▪ Incidentals	10.00	(for example – parking, laundry for extended stays, etc.)
▪ Daily Maximum	$ 43.50	

If per diems are being used, supporting documentation for the amounts exceeding the daily maximum must be provided.

8. Telecommunication

Personal telephone calls home by employees travelling on Company business will be allowable provided such calls are kept to a reasonable minimum and do not exceed $10.00 per week.

Charges for long distance business calls and other telecommunications for business purposes which are paid by the employee may be claimed as an expense. Calling cards are available by contacting an Administrative Assistant at 180 Kent Street – 4th Floor.

Cellular telephones expense charged to the Company should exclude the cost of personal calls.

9. Extended Travel

When employees are required to work on projects, which necessitate that they reside away from their normal residence for extended periods of time, arrangements with respect to transportation and accommodation shall be worked out in advance between the employee and Supervisor. Details of these arrangements shall be attached to the employees' expense reports or Corporate P-Card statements.

Employees may elect to be paid an allowance of $75.00 per day instead of a combination of accommodations, meals and other expenses. In addition, the employee may claim, substantiated by receipts, up to $10.00 per week for long distance telephone calls.

When an employee elects to travel to the work assignment daily, the Company may offer, in lieu of meals and accommodations, one of the following alternatives:

i. A travel allowance as follows:
- 0 - 40 kilometres $31.00 per day
- 41 - 80 kilometres $38.00 per day
- 81 kilometres and over $43.00 per day

Under this alternative, kilometres are measured one way and the employee supplies the transportation.

OR

ii. Provide transportation for the employee each day to and from the work assignment.

Under these alternatives, all travel shall be on the employee's own time.

Note: For bargaining unit employees, when the overnight accommodations are not provided, the collective agreement shall prevail. (Article 20.02)

10. Entertainment

The nature of our business is such that the necessity to host business associates is minimal. Claims for entertainment expenses shall normally be confined to senior management personnel. It is recognized, however, that some employees, because of their work, have contact with others outside the Company where it is necessary, on occasion, to provide Company hospitality. Employees in this category shall obtain prior approval from their Manager.

11. Personal Expenses
Personal expenses incurred while travelling on Company business should not be recorded on expense reports or purchased with a Corporate P-Cards. These expenses remain the employee's responsibility.

12. Corporate Purchasing Cards (P-Cards)
Cardholders will receive a monthly statement identifying each transaction made against the card during the previous billing period. The statements are printed by cardholders or group coordinators. For further information on the Corporate P-Card Program, refer to Procedure #603003.

13. Reconciliation
    1. The Corporate P-Cardholder reconciles all credit card receipts to the transactions listed on their statement.
    2. The Corporate P-Cardholder verifies that all transactions are correct.
    3. The Corporate P-Cardholder enters comments about the transaction directly into the Centresuite (Scotiabank Commericial Card) Software and also, if required, makes corrections to the account number.
    4. Any discrepancies must be identified and the appropriate action taken to resolve the problem.
    5. Corporate P-Cardholder signs reconciled statement and forwards it with receipts attached to their Supervisor for approval (in the case of air travel boarding passes are to be submitted).
    6. Completed statements are forwarded to the Administrative Assistant on the 4th Floor, 180 Kent Street, for filing.

14. Use of Petty Cash to Reimburse Out-Of-Pocket Expenses
Minor travel and business expenses may be incurred "out-of-pocket" by employees where the use of Corporate P-Cards is not permissible (taxis, highway tolls, etc.). Employees may be reimbursed for such costs out of Cashier's petty cash with Supervisor approval and appropriate documentation of expense, up to a maximum of $100.

15. The Vice President, Finance, Corporate Services and Chief Financial Officer or the Manager, Financial Reporting is responsible for interpreting this policy, as necessary, and for recommending revisions.

I N T E R R O G A T O R I E S

IR-13 – Attachment 1

Breakdown of
Section 5 – Distribution Spending by Subcategory

Breakdown of Section 5 - Distribution Spending by Subcategory for 2012 to 2021										
Distribution	**2012 Actual**	**2013 Actual**	**2014 Actual**	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Budget**
5.1 Replacements – Storms, Collisions, Fire and Road Alterations	$ 1,240,335	$ 1,315,337	$ 1,415,152	$ 1,907,865	$ 1,997,881	$ 1,276,552	$ 2,782,221	$ 2,119,728	$ 1,816,083	$ 1,446,000
5.2 DistributionTransformers	2,978,466	2,697,910	2,871,515	2,784,256	2,866,611	3,354,755	3,267,447	4,711,370	3,809,592	5,192,000
5.3 Services and StreetLighting	3,700,620	3,659,516	3,787,503	4,078,108	4,289,762	4,882,276	5,112,198	4,917,056	5,233,172	5,301,000
5.4 Line Extensions	1,987,694	1,445,940	2,071,556	1,687,655	3,135,552	2,647,262	2,622,794	3,570,453	4,165,043	2,232,000
5.5 Line Rebuilds	3,895,153	3,400,049	3,140,823	3,265,083	2,915,755	4,072,242	4,282,026	4,284,513	4,641,568	9,365,000
5.6 System Meters	1,252,094	997,332	798,954	415,481	466,266	441,884	618,047	667,417	888,194	620,000
5.7 Distribution Equipment	1,452,221	1,682,493	1,666,931	1,505,023	1,744,897	1,399,214	1,891,742	1,856,059	1,689,666	2,035,000
5.8 TransportationEquipment	865,266	509,151	1,221,821	488,597	829,582	1,760,278	869,012	1,651,140	1,287,481	1,864,000
TOTAL	**$ 17,371,849**	**$ 15,707,728**	**$ 16,974,255**	**$ 16,132,068**	**$ 18,246,306**	**$ 19,834,463**	**$ 21,445,487**	**$ 23,777,736**	**$ 23,530,799**	**$ 28,055,000**

Breakdown of Section 5 - Distribution Spending by Subcategory for 2012 to 2021 (Normalized at 2% Annual Inflation)										
Distribution	**2012 Normalized**	**2013 Normalized**	**2014 Normalized**	**2015 Normalized**	**2016 Normalized**	**2017 Normalized**	**2018 Normalized**	**2019 Normalized**	**2020 Normalized**	**2021 Budget**
5.1 Replacements – Storms, Collisions, Fire and Road Alterations	$ 1,488,402	$ 1,541,575	$ 1,626,010	$ 2,148,256	$ 2,205,661	$ 1,381,229	$ 2,951,936	$ 2,204,517	$ 1,852,405	$ 1,446,000
5.2 DistributionTransformers	3,574,159	3,161,951	3,299,371	3,135,072	3,164,739	3,629,845	3,466,761	4,899,825	3,885,784	5,192,000
5.3 Services and StreetLighting	4,440,744	4,288,953	4,351,841	4,591,950	4,735,897	5,282,623	5,424,042	5,113,738	5,337,835	5,301,000
5.4 Line Extensions	2,385,233	1,694,642	2,380,218	1,900,300	3,461,649	2,864,337	2,782,784	3,713,271	4,248,344	2,232,000
5.5 Line Rebuilds	4,674,184	3,984,857	3,608,806	3,676,483	3,218,994	4,406,166	4,543,230	4,455,894	4,734,399	9,365,000
5.6 System Meters	1,502,513	1,168,873	917,998	467,832	514,758	478,118	655,748	694,114	905,958	620,000
5.7 Distribution Equipment	1,742,665	1,971,882	1,915,304	1,694,656	1,926,366	1,513,950	2,007,138	1,930,301	1,723,459	2,035,000
5.8 TransportationEquipment	1,038,319	596,725	1,403,872	550,160	915,859	1,904,621	922,022	1,717,186	1,313,231	1,864,000
TOTAL	**$ 20,846,219**	**$ 18,409,457**	**$ 19,503,419**	**$ 18,164,709**	**$ 20,143,922**	**$ 21,460,889**	**$ 22,753,662**	**$ 24,728,845**	**$ 24,001,415**	**$ 28,055,000**

I N T E R R O G A T O R I E S

IR-16 – Attachment 1

Breakdown of
Section 6 – Transmission Spending by Subcategory

Breakdown of Section 6 - Transmission Spending by Subcategory for 2012 to 2021										
Transmission	**2012 Actual**	**2013 Actual**	**2014 Actual**	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Budget**
6.1 Substation Projects	$ 2,708,940	$ 1,902,242	$ 2,076,501	$ 2,258,942	$ 2,868,144	$ 3,924,090	$ 3,696,076	$ 6,199,648	$ 5,060,020	$ 6,043,000
6.2 Transmission Projects	596,528	2,204,553	4,386,370	5,833,897	5,415,107	6,804,362	3,293,454	2,474,370	2,794,788	5,485,000
TOTAL	**$ 3,305,468**	**$ 4,106,795**	**$ 6,462,871**	**$ 8,092,839**	**$ 8,283,251**	**$ 10,728,452**	**$ 6,989,530**	**$ 8,674,018**	**$ 7,854,808**	**$ 11,528,000**

Breakdown of Section 6 - Transmission Spending by Subcategory for 2012 to 2021 (Normalized at 2% Annual Inflation)										
Transmission	**2012 Normalized**	**2013 Normalized**	**2014 Normalized**	**2015 Normalized**	**2016 Normalized**	**2017 Normalized**	**2018 Normalized**	**2019 Normalized**	**2020 Normalized**	**2021 Budget**
6.1 Substation Projects	$ 3,250,728	$ 2,229,428	$ 2,385,900	$ 2,543,569	$ 3,166,431	$ 4,245,865	$ 3,921,537	$ 6,447,634	$ 5,161,220	$ 6,043,000
6.2 Transmission Projects	715,834	3,791,831	5,039,939	6,568,968	5,978,278	7,362,320	3,494,355	2,573,345	2,850,684	5,485,000
TOTAL	**$ 3,966,562**	**$ 4,813,164**	**$ 7,425,839**	**$ 9,112,537**	**$ 9,144,709**	**$ 11,608,185**	**$ 7,415,891**	**$ 9,020,979**	**$ 8,011,904**	**$ 11,528,000**

INTERROGATORIES

IR-19 – Attachment 1

Y-109 and Y-111 Inspection Report

Y-109 AND Y-111 INSPECTION REPORT

Prepared by Cale Doyle

December 2016

Y-109 and Y-111 runs between West Royalty substation and Bedeque switching stations. Y-109 was built in 1979 and Y-111 was built in 1987. The inspection was performed with Y-109 lines energized and Y-111 de-energized to perform ground repairs on the fiber line. The results of this inspection were that all the tangent structures in dry areas are cracked so bad that they failed on visual, not even making it to the pole tester stage of the inspection process. Poles that were in wet areas and any 3 pole structures seem to not crack at all or to the extreme as the tangents. The number one priority found was that the majority of the H-frame structures have large cracks which led the inspection team to fail the poles. A typical example was finding poles having a 13" diameter with a crack that measured 1" wide by 8½ " deep. That makes the cracks over 65 percent of the pole (see pictures below).


9
10


136

The picture below is an example of a marginal pole that tested good at the base, but it was rotten at the top of the pole.

Y-109

The DART team found that Y-109, the older of the two lines, was in the worse condition and they had to do repairs on it.

194 structures on Y-109

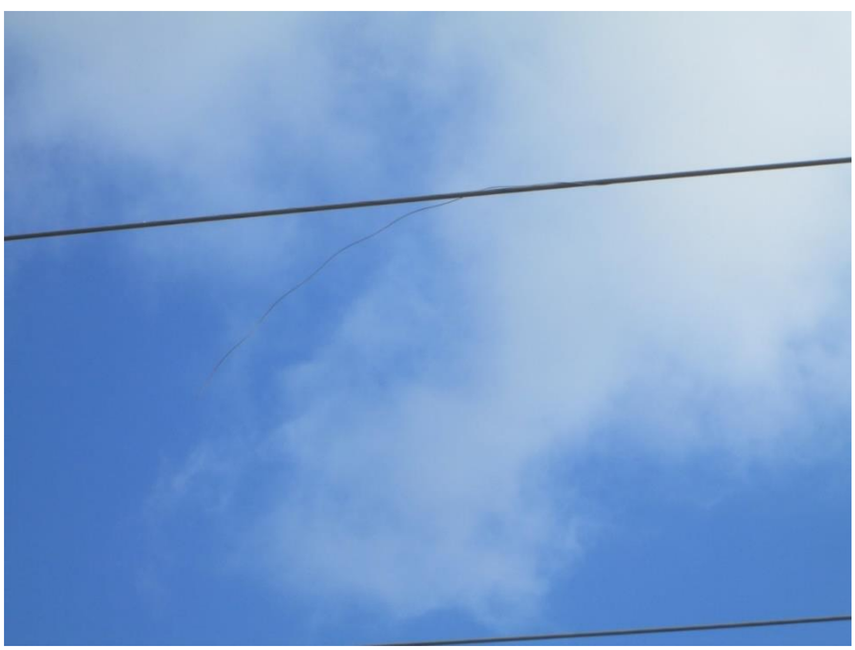
- 70 structures failed inspection on Y-109 (36% of the structures); and
- 15 more structures are on the marginal (7% of the structures)

The DART team did some repairs as they went. Below are photos of the some of the repairs

This is Structure 115. The crossarm had a large chunk of the arm missing and a few major cracks. The DART team changed out the arm along with the insulators.

The DART team also did the same repair on the next structure, Structure 116 (picture below), where they replaced the cross arm and reinsulated the structure. They also reinsulated structures 113, 114, 117, 118, and 120. This was due to a number of insulator failures.

Structure 117 had a strand unwound on the center phase mid span and needed repair (see picture below).



There was 135 spans of tree trimming identified during the inspection (picture below). It is hard to tell from the picture, but the trees are only a foot away from the wire.

Y-111

Y-111 was de-energized during this inspection. The DART team were repairing the bond wire on the fiber wire (see picture below).

Y-111 was found to be in a lot better shape than Y109.

Y-111 has 190 structures

- only 3 structures failed, and
- 50 poles failed (this includes the 6 poles in the 3 failed structures).

Saying this, it would be better suited to change out the whole structure while there instead of replacing just one pole.

Most of the poles failed due to large cracks (see pictures below).

There also seemed to be some insect infested poles, and that is what failed two (Structure 56) of the structures (see pictures below).

One pole fail due to rot. The picture below show a DART member using a screw driver and very easily incerting it in the pole and removing pieces of the pole.

There is also 143 spans of tree trimming on Y-111. The tree trimming for both of these lines have been given to Vegation Management and will be addressed this year.

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A FORTIS COMPANY
All our energy.
All the time.

I N T E R R O G A T O R I E S

IR-19 – Attachment 2

Summary of Capital Expenditures (2012-2026)

Maritime Electric Company, Limited Summary of Capital Expenditures (2012-2026)															
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020***	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Budget**	**Budget**	**Budget**	**Budget**	**Budget**	**Budget**
Generation															
Charlottetown Plant and CT3	844,766	669,275	592,872	451,154	500,777	983,658	814,902	426,114	1,133,998	4,640,000	452,000	1,315,000	1,184,000	2,871,000	13,087,000
Borden Plant	59,333	881,322	1,468,960	234,642	740,335	81,062	185,765	59,226	291,417	305,000	643,000	633,000	573,000	221,000	680,000
Sub-total	904,099	1,550,597	2,061,832	685,796	1,241,112	1,064,720	1,000,667	485,340	1,425,415	4,945,000	1,095,000	1,948,000	1,757,000	3,092,000	13,767,000
Distribution and Transmission															
Distribution	17,371,849	15,707,728	16,974,255	16,132,068	18,246,306	19,834,463	21,445,487	23,777,736	23,530,799	28,055,000	37,371,000	37,233,000	40,317,000	30,884,000	31,352,000
Transmission	3,305,468	4,106,795	6,462,871	8,092,839	8,283,251	10,728,452**	6,989,530	8,674,018	7,854,808	11,528,000	8,640,000	8,806,000	8,923,000	10,382,000	13,886,000
Sub-total	20,677,317	19,814,523	23,437,126	24,224,907	26,529,557	30,562,915	28,435,017	32,451,754	31,385,607	39,583,000	46,011,000	46,039,000	49,240,000	41,266,000	45,238,000
Corporate	997,025	757,930	979,141	897,585	1,039,510	945,707**	2,143,044	1,850,589	1,894,378	2,527,000	7,186,000	12,164,000	3,761,000	2,487,000	2,538,000
Sub-total	22,578,441	22,123,050	26,478,099	25,808,288	28,810,179	32,573,342	31,578,728	34,787,683	34,705,400	47,055,000	54,292,000	60,151,000	54,758,000	46,845,000	61,543,000
Capitalized General Expense	263,704	350,331	388,730	458,433	477,714	502,450	475,368	567,505	489,745	518,000	690,000	705,000	719,000	734,000	750,000
Interest During Construction	295,027	298,913	368,486	376,452	405,915	449,760	432,111	474,433	44,170	642,000	686,000	649,000	686,000	561,000	772,000
Sub-total	23,137,172	22,772,294	27,235,315	26,643,173	29,693,808	33,525,552	32,486,207	35,829,621	35,639,315	48,215,000	55,668,000	61,505,000	56,163,000	48,140,000	63,065,000
Less: Customer Contributions	(760,444)	(643,920)	(525,236)	(382,693)	(1,262,517)	(746,454)	(677,905)	(758,922)	(1,094,598)	(3,107,000)	(8,538,000)	(8,621,000)	(750,000)	(750,000)	(750,000)
Net Capital Expenditures	**22,376,728**	**22,128,374**	**26,710,079**	**26,260,480**	**28,431,291**	**32,779,098**	**31,808,302**	**35,070,699**	**34,544,717**	**45,108,000**	**47,130,000**	**52,884,000**	**55,413,000**	**47,390,000**	**62,315,000**

Note: Actual amounts above, where applicable, include amounts expended for approved carryovers from the previous year.

* Unaudited and Capital Budget Orders UE19-09 and UE20-02.

** A carryover of $103,921 for project 2016-7.1 (b) West Royalty Service Centre Improvement Plan was incorrectly classified in Transmission expenditures in prior reporting to the Commission. The reclassification from Transmission to Corporate expenditure is reflected in this Appendix.

I N T E R R O G A T O R I E S

IR-20 – Attachment 1

Breakdown of
Section 7 – Corporate Spending by Subcategory

Breakdown of Section 7 - Corporate Spending by Subcategory for 2012 to 2021										
Corporate	**2012 Actual**	**2013 Actual**	**2014 Actual**	**2015 Actual**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Budget**
7.1 Corporate General	$ 166,385	$ 34,534	$ 450,158	$ 232,698	$ 114,862	$ 76,499	$ 1,066,003	$ 640,500	$ 458,886	$ 411,000
7.2 Information Technology	830,640	723,396	528,983	664,887	924,648	765,287	1,077,041	1,210,449	1,435,492	2,116,000
TOTAL	**$ 997,025**	**$ 757,930**	**$ 979,141**	**$ 897,585**	**$ 1,039,510**	**$ 841,786**	**$ 2,143,044**	**$ 1,850,949**	**$ 1,894,378**	**$ 2,527,000**

Breakdown of Section 7 - Corporate Spending by Subcategory for 2012 to 2021 (Normalized at 2% Annual Inflation)										
Corporate	**2012 Normalized**	**2013 Normalized**	**2014 Normalized**	**2015 Normalized**	**2016 Normalized**	**2017 Normalized**	**2018 Normalized**	**2019 Normalized**	**2020 Normalized**	**2021 Budget**
7.1 Corporate General	$ 199,662	$ 40,474	$ 517,232	$ 262,018	$ 126,808	$ 82,772	$ 1,131,029	$ 666,120	$ 468,064	$ 411,000
7.2 Information Technology	996,768	847,820	607,801	748,663	1,020,811	828,041	1,142,741	1,258,867	1,464,202	2,116,000
TOTAL	**$ 1,196,430**	**$ 888,294**	**$ 1,125,033**	**$ 1,010,681**	**$ 1,147,619**	**$ 910,812**	**$ 2,273,770**	**$ 1,924,613**	**$ 1,932,266**	**$ 2,527,000**