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MARITIME ELECTRIC
A FORTIS COMPANY

September 30, 2020

Island Regulatory and Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Commissioners:

2020 Integrated System Plan

Please find enclosed six copies of the Company's 2020 Integrated System Plan ("ISP"). The ISP includes the long term plan for energy system utilization at the CTGS site as required under Order UE19-08 item 25 and addresses the requirements listed under item 26 of the Order.

An electronic version copy will follow shortly. If you have any questions, please do not hesitate to contact me at 902-629-3641.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

Gloria Crockett, CPA, CA
Manager, Regulatory & Financial Planning

GCC16
Enclosure

Maritime Electric Company, Limited
2020
Integrated System Plan

Release Date: September 2020

Prepared By: Corporate Planning

EXECUTIVE SUMMARY

The purpose of this Integrated System Plan document is to provide context for capital budget applications, and an advance indication of major projects and technological trends and developments that the Company foresees. Some of the upcoming projects are due, directly or indirectly, to climate change and the Provincial Government's associated policies. Others are driven by advancing technology and the value and benefits it can bring to the Company's customers.

Load Patterns and Drivers

Electrification of both space heating and transportation will increase system loading, and will drive additional infrastructure to serve the customers' supply and reliability needs. Electrified space heating has been on an upward trend for the past decade, and has driven most of the load growth through this period. The system has been able to accommodate this growth mostly through spare capacity that was previously built into the system.

Electrified transportation currently has little penetration in the PEI passenger vehicle market and negligible impact on electric energy or demand requirements. Few significant impacts are expected in the next five years in absence of Provincial purchase incentives. In the longer term both energy and infrastructure impacts will be seen as electric vehicles become more commonplace. Shifting charging to off-peak will help reduce the amount of additional system infrastructure required to support electric vehicle charging, and to facilitate this a change in rate structures will likely be needed. Maritime Electric has to look forward, plan for the increases in load, and begin to build spare capacity into the system now or it will be incapable of accommodating electric vehicle charging on a local level. A failure to achieve widespread off-peak charging will lead to large infrastructure increases and associated costs to enable charging during peak periods.

Generation and Storage

The closure of the Charlottetown Thermal Generating Station ("CTGS") in 2022 will remove all heavy fuel oil-based generation from the Company's fleet. Maritime Electric will have 90 MW of diesel-fired generation remaining on-Island for backup and emergency purposes. Over 60 per cent of the Company's capacity requirements will come from off-Island sources and will be delivered through the mainland transmission system after the CTGS closure. Modelling indicates that the Island could see significant rotating outages during the rare event of an extended outage to the mainland connection as only a limited amount of wind energy can be supplied when load following is provided by on-Island generation. As a result, additional on-Island dispatchable generating capacity is required to secure the Company's supply during times of transmission constraint and to provide backup and emergency services. Dispatchable generation is generation where the fuel source can be controlled – if the fuel source is controllable, the output is controllable. Combustion turbines, hydro, nuclear and steam turbines are examples of dispatchable generation. Solar and wind are non-dispatchable, since the output of these resources cannot be controlled with the precision required to operate a reliable electric system.

Additional dispatchable generation should be connected to the 69 kV system so it can help offload the 138/69 kV transformers as well as provide emergency and backup services. A minimum of 50 MW of additional generation should be installed in the Charlottetown area in 2024 to provide capacity, voltage, and operational support. This would replace the capacity lost due to the retirement of the CTGS. The Borden combustion turbines, which are approaching end of life, should be replaced with an updated combustion turbine around 2030, with the new turbine located at either Sherbrooke or Borden stations.

Renewable energy will continue to increase its proportionate share of Maritime Electric's energy supply mix. Wind energy costs of production continue to drop, and the Company will look to increase its use of this Island resource when it can reasonably be fit under the load curve and supplied at a reasonable cost. Wind has little capacity value as it cannot be reliably dispatched. The PEI Energy Corporation retains responsibility for planning future Island wind projects.

Solar energy remains uneconomic without substantial government subsidies, and provides no capacity value since peak solar output does not align with Island system peak. Unsubsidized rooftop solar is approximately twice as expensive as utility-scale ground mounted solar to install per unit of energy output.

The cost of energy storage continues to fall as the technology matures but remains uneconomic. Individual customers may choose to install storage for their own needs. Maritime Electric does not believe that utility control of an array of individual customer devices, with the control devices, communications and security needed to undertake the program, will provide an economic capacity resource at this time. Maritime Electric can secure both ancillary services and capacity more economically from other sources.

<u>Transmission</u>

The transmission system needs to expand to meet the increasing energy and demand needs of Maritime Electric's customers. The January 2020 system peak of 287 MW is approaching PEI's import maximum of 300 MW, meaning there will be periods during which on-Island generation will have to be operating or dispatched in the next several years when the Island load exceeds the 300 MW level. CT3 will continue to be a versatile backup for both normal system loading and contingency situations.

As the Island load grows, under-voltage load shedding will be required in eastern PEI to maintain system stability in absence of operating generation. A system collapse may occur for a loss of Y-111 at load levels in excess of 330 MW. To prevent this occurrence, a 138 kV supply to Lorne Valley will be necessary to help support eastern PEI as load levels increase.

A third west to east 138 kV transmission line will help solidify the west-east transfer, lowering losses and enabling the system to withstand loss of Y-109 or Y-111 during peak loading periods. This line should be routed from Borden/Bedeque to Scotchfort, and continued to Lorne Valley, to promote geographical separation between transmission facilities. The connection to Lorne Valley will be required at a load levels above 375 MW, but completion prior to that will provide additional times when preemptive generation operation will not be required to avoid load shedding.

A 138/69 kV stepdown transformer in the O'Leary or Mount Pleasant area will provide an increase in reliability and significant voltage support for western PEI customers. It will also help offload the Sherbrooke transformers that are approaching their rated thermal levels. Distribution-connected capacitors in western PEI will be required to help support local transmission and distribution voltages during peak loading.

<u>Distribution</u>

Distribution facilities were not historically planned with electrified space heating and future electrified transportation in mind. These applications will change the intensity of use, and will drive the need for additional distribution facilities. To maximize the use of existing lines and conductors, distribution substations should be spaced 15-20 km apart to meet both thermal and voltage operating requirements. Substations located further apart will require extensive distribution line rebuilds.

Electrified transportation will drive system upgrades on a local level since the greater system impacts will be experienced closer the customer. Neighbours simultaneously charging their vehicles can overload the pole-to-residence service, but will not overload the upstream infrastructure. Programs to encourage off-peak charging will help minimize the impact on existing infrastructure and will encourage more efficient use of the system.

There are no new substations planned in the short term once the East Royalty Substation is complete in 2022. Distribution work will focus on upgrading substation transformers, system hardening, and establishing distribution connections between neighbouring substations. There are several substation locations being considered in the medium to long term depending on area load growth, including Tignish, Mount Pleasant, Bedeque and Cavendish. Distribution automation will also be explored, with several small projects undertaken to determine the effectiveness and capabilities of the technology.

Charlottetown will have insufficient transformer capacity after the CTGS transformers are decommissioned. Maritime Electric is exploring several options in the medium to long term, including additional transformer capacity at the Charlottetown Plant site.

Technology

Technology continues to change the way the Company conducts its business. Customer access to data and control of load, data analytics, diversified energy generation and storage, and satellite technology may become part of the Company's business practices in the medium to long term.

Widespread electrified transportation will drive demand-side management ("DSM") programs that can help suppress system peak to make best use of existing system resources and minimize the amount of additional infrastructure investment required. DSM can be delivered through a variety of means, including time of use rates, customer load control, and automatic timers, which requires that a long term system planning view needs to be taken.
Many emerging technologies are presently uneconomic or will not have a substantial impact on customer energy use or patterns. Technological changes will not take place overnight, and the Company intends to implement them as their societal value and the economic benefit to ratepayers comes into focus.

System Upgrades

The following significant system actions are required in the next five years to support the expansion of electricity use as well as maintain or improve customer reliability:

- Install one medium-sized (50-75 MW) on-Island dispatchable generator at the Charlottetown Plant site by 2024 in order to a) replace the capacity lost with the closure of the Charlottetown Thermal Generating Station, and b) provide backup capability alongside Combustion Turbine #3;
- Replace end-of-life Y-109 by building Y-119 on a new route in the 2021-2023 timeframe, and take Y-109 out of service when Y-119 is complete;
- Replace West Royalty substation transformers X5 and X6 with 75 MVA 138/69 kV transformers in 2023 and 2026, respectively, due to transformer condition and increasing load;
- Rebuild the end-of-life sections of line T-11 between Sherbrooke and the City of Summerside in the 2024 timeframe;
- Construct a 138/69kV connection in the O'Leary/Mount Pleasant area in 2024 to provide voltage support to western PEI load customers and maintain customer supply during maintenance on existing facilities;

- Install a new distribution substation in the East Royalty area of Charlottetown by 2022 to accommodate load growth north and east of Charlottetown;
- Decommission the end-of-life line T-4 between Scotchfort and Lorne Valley once East Royalty is complete, remove Scotchfort Substation from service, and redeploy the Scotchfort transformer in the system;
- Build distribution line extensions between neighbouring substations to help with maintenance and storm restoration options;
- Replace end-of-life radio links, mobile radio systems and communications equipment to ensure reliable communications and meet cybersecurity requirements;
- Add distribution automation in select areas to determine its effectiveness and applicability to the Maritime Electric system; and
- Modernize or reconstruct substations to ensure they have long-term flexibility, expansion options and improved reliability, can accommodate a mobile transformer as needed, and have communications and protection and control equipment that meets cybersecurity needs.

In the longer term the following actions are required to supply the increasing needs of electrified transportation and general system growth:

- Replace the early-1970s vintage Borden combustion turbines in the 2030 timeframe, by which time the existing units will be approximately 60 years old;
- Add on-Island generating capacity, over and above the generator proposed in 2024, to provide backup to the growing Island load and reduce the Island's dependence on mainland capacity to less than 50 per cent. This generation should be located near a major load centre on the 69 kV system to extract the maximum benefit from the equipment;
- Install a 138/69 kV connection at Lorne Valley when Island load approaches 350 MW to provide adequate thermal load-serving capability to eastern PEI, along with a 138 kV connection between existing Y-104 and Lorne Valley;
- Complete a third west-to-east 138 kV line between Borden/Bedeque and a new Scotchfort switching station to increase west to east transfer and minimize generation operation when system contingencies or maintenance occurs;
- Locate substations in Tignish, Cavendish, O'Leary/Mount Pleasant and Bedeque as needed to meet the increasing load;
- Reinforce load supply in downtown and eastern Charlottetown by installing a 138 kV source at the Charlottetown substation at the CTGS site; and
- Add distribution substations on or close to existing transmission facilities to facilitate 15-20 km spacing between rural distribution substations.

The Charlottetown Plant site is required by Maritime electric as it is the desired location for the next dispatchable generator, is located close to existing fuel off-loading and storage facilities, provides long-term load serving capacity to downtown and eastern Charlottetown, and provides long-term options for energy storage. In addition, Maritime Electric intends to undertake studies on islanded wind operation and the West Royalty substation in the short to medium term.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

APPENDICES

1. INTRODUCTION

Maritime Electric Company, Limited ("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 generation, transmission and distribution of electricity to customers throughout PEI.

The purpose of this Integrated System Plan document is to provide context for capital budget applications and an advance indication of major projects in addition to the annual capital budgets. Cost estimates are preliminary in nature, and may not align with those presented in Capital Budget submissions.

MECL's current challenges for reliably serving short and medium term customer load can be summarized as follows:

- Expanding use of electric heat, primarily through the use of mini-split heat pumps, is driving system peak load up, particularly in the winter heating season. Significant summer peak load growth has occurred in the past two summers as heat pumps can provide cooling in summer months. Growth is not uniform across the province, and targeted system expansion is required to meet customer needs.
- Widespread electrification of transportation is on the horizon, and MECL must plan and build its system to meet both load-serving and reliability needs for this emerging sector.
- Tree contacts continue to cause reliability issues, particularly in autumn and early winter during wind and/or wet snow storms. System events in November 2018 and September 2019 highlighted this issue. The extensive outages incurred during post-tropical storm Dorian were almost exclusively caused by trees falling onto power lines.
- Increased reliance on electric heat is expected to drive higher customer reliability requirements, particularly since loss of this heating source during winter can have a significant impact on personal well-being and property safety.

This document differs from an Integrated Resource Plan as this document concentrates on Maritime Electric's transmission and distribution systems and does not undertake a detailed examination of on-Island energy sources. Integrated Resource Plans are typically produced by utilities with resources available to produce economic supplies of dispatchable energy in addition to the delivery facilities. PEI's only economic generation resource is wind generation, and the Government of PEI – through the PEI Energy Corporation ("Energy Corporation") – has taken defacto control over approval and ownership of on-Island generation.

The Energy Corporation has also taken control of demand side management ("DSM") program development and delivery, and through the Energy Strategy[1] has publicized its vision for future renewable energy integration into the Island's supply mix. Future Island-based energy supply and DSM decisions are presently determined by the Energy Corporation, who have responsibility to determine their reliability, economics and integration.

[1] Prince Edward Island Provincial Energy Strategy 2016/17

The results of this Integrated System Plan may change as load forecasts or Island growth patterns change.

2. SYSTEM PLANNING

Planning is a continuously evolving process designed to meet the present and changing needs of a variety of stakeholders. Planning is generally divided into short, medium and long term timeframes, with ongoing interaction between all three.

Short term or operational planning involves developing specific plans to implement projects defined in the current year budget, as well as operating the system in a safe and reliable manner. It also addresses immediate needs, such as customer connections not previously identified, or reaction to external events such as a severe ice storm.

Medium term planning is performed each year in order to incorporate new information that may arise, such as new regulations, increased load growth, updated asset condition reports, and extraordinary initiatives such as DSM. Long term planning generally covers the time horizon beyond five years and is typically performed every three to five years, or as system conditions dictate.

Generation planning is undertaken on a long term basis, often in conjunction with transmission studies given their close relationship. Maritime Electric's long range transmission planning must account for PEI's peak demand due to Maritime Electric's role as the provincial transmission planner through the Open Access Transmission Tariff ("OATT"). The last Transmission Plan was developed in 2014 with an addendum produced in spring 2016. A study of the transmission system undertaken in Q2 2020 concluded that transmission system trends and solutions have not demonstrably changed since 2016, and as such a full transmission study document is not presently required and has not been produced.

Distribution planning is performed through the preparation and periodic review of long term system planning studies for the organization. While system planning studies separately analyse the existing transmission and distribution systems, neither is done in isolation.

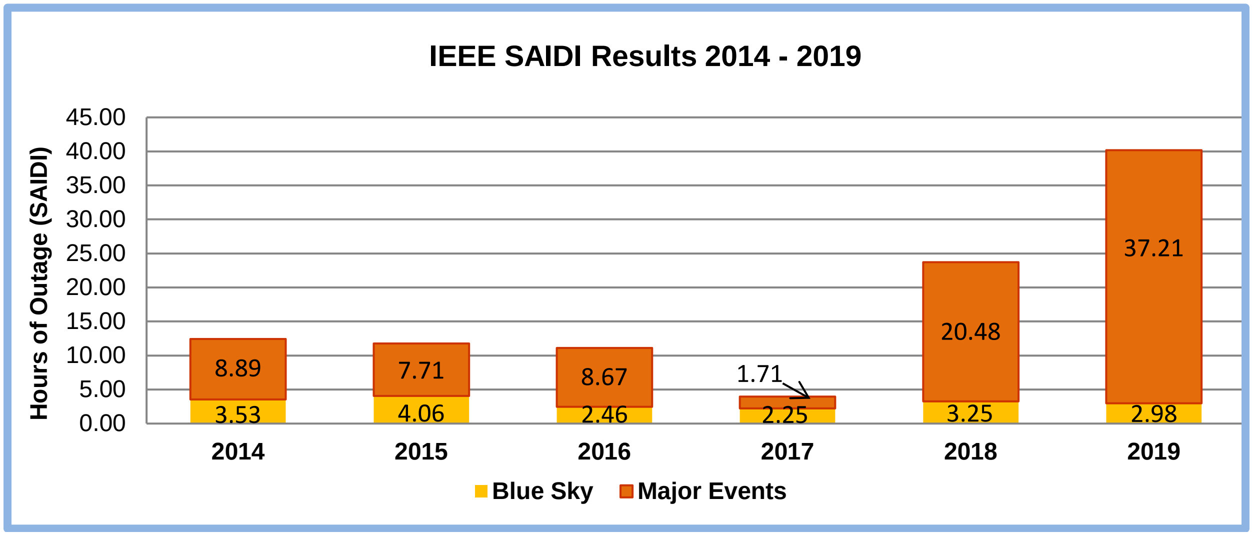
The increasing reliance on electricity for heating and projected transportation requirements will serve to drive increased customer demands for reliability.

3. SYSTEM PERFORMANCE AND RELIABILITY

Excluding Major Events, the average customer experienced 2.98 hours of outage (SAIDI) in 2019 compared to 3.25 hours for 2018 (using the IEEE methodology).

Reliability Statistics				
	4th Quarter		Year to Date	
	2019	2018	2019	2018
Average Hours of Outage (SAIDI)	1.49	1.09	2.98	3.25
Unscheduled Outages	1.19	1.06	2.41	2.74
Scheduled Outages	0.30	0.03	0.57	0.51
Average Number of Interruptions (SAIFI)	1.12	0.73	2.31	2.25

The benchmark for SAIDI using the IEEE methodology and based on 97% of the three-year moving average was 2.57 hours for 2019.



Maritime Electric monitors the metrics to determine what trends, if any, are developing. Reliability indicators assist in developing the programs within this Integrated System Plan through cause analysis. Significant work has taken place in specific areas where the infrastructure was visibly aging, or where trend analysis indicated deficiencies.

3.1. Target Customer Reliability Levels

In the electric utility business there is a continuous balancing act between reliability and cost since increased reliability usually comes at increased cost. Maritime Electric feels that its past and current practices have provided a reasonable balance between what customers require and the cost of providing those services to the customer.

PEI is situated in a climatic zone where harsh weather can impact customer supply, particularly in the winter due to wet snow, freezing rain, and wind conditions. The recent trend towards increased reliance on electricity - particularly for space heating - means that system reliability has to be at least maintained, if not increased. While customers should always have a backup heat source in case of a failure to the primary source, this is not always the case. This is exacerbated in an extended outage situation.

Maritime Electric's target reliability level is to meet the average of the past five years of SAIDI, less five percent.

Reliability is impacted by many things, including location of electrical infrastructure. Historically distribution lines were always built road-side, while transmission lines were often built off-road (cross country). Roadside is now typically the preferred location for both transmission and distribution due to its ease of access for installation as well as maintenance.

3.2. Enhancing Customer Reliability

Customer interruptions of the same length can vary in severity, depending on the time of year and type of customer load. This is still the case even if economic impacts are ignored. PEI's gradual shift towards reliance on electric heat is increasing the severity of each prolonged interruption. Maintaining or improving customer reliability is imperative.

Customer reliability is enhanced by continuously investing in system equipment and infrastructure to ensure that equipment is in good working condition and can handle the climatic conditions that it needs to endure. Controlling vegetation that grows near equipment is also important to maintaining reliable service to customers.

Vegetation management is a key component of maintaining transmission and distribution system customer reliability. Maritime Electric has increased its vegetation management program over the past several years in order to keep vegetation-related outages to a minimum. Ideally, the vegetation management rotation would be a five- to seven-year period. This would ensure that only a minimum amount of vegetation can get close to Maritime Electric's facilities. In addition, rights of way would ideally be cut to the ground. This is not always the case, especially on private land. Trees underneath Maritime Electric's lines are often 'topped' a certain distance above ground. This is both expensive to undertake and more costly to maintain.

4. CLIMATE CHANGE AND SUSTAINABILITY

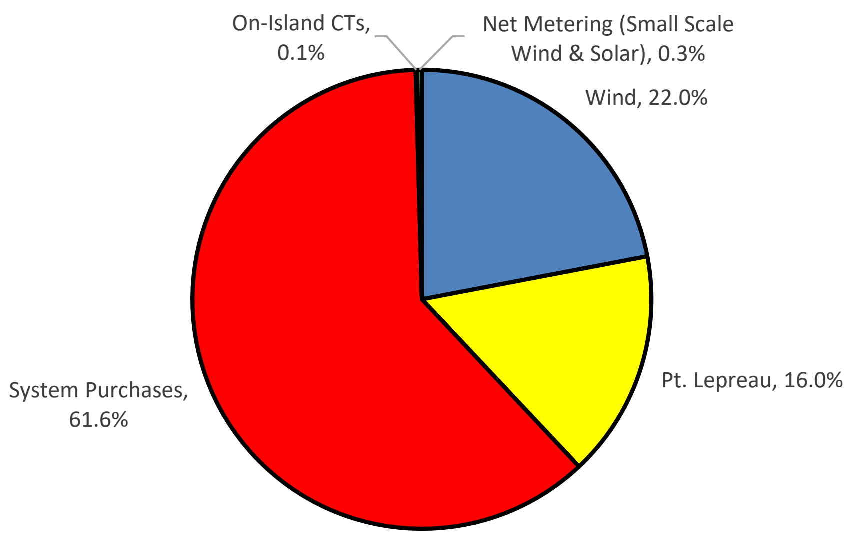
"There is now overwhelming evidence that climate change is occurring and the consequences may be quite serious for our Island province."[2] Climate change is now one of the leading factors in the Company's decision-making process as Maritime Electric's generation, transmission and distribution infrastructure is, and will continue to be, impacted by climate change.

Maritime Electric is not currently undertaking significant efforts to move its existing infrastructure as it has minimal current exposure to coastal flooding. The location and design of future infrastructure will take into account rising sea levels and storm surges, increased wind and ice loading, and higher summer ambient temperatures.

Maritime Electric's energy sources in 2019 are shown in Figure 1.

2 '*Taking Action. A Climate Change Action Plan for Prince Edward Island 2018-2023*'; Government of Prince Edward Island, Page 2.

Figure 1 Maritime Electric Energy Sources 2019



The approximate carbon content of Maritime Electric's energy supply is shown in Table 1.

Table 1
Maritime Electric Supply Carbon Content 2019

Source	Amount	Carbon Content (kg/kWh)
Wind	22.0%	0
Pt. Lepreau (nuclear)	16.0%	0
System Purchases (mix of wind, hydro, coal, gas)	61.6%	0.3[3]
On-Island CTs (diesel)	0.1%	0.8
Net Metering (wind and solar)	0.3%	0
Weighted Average		**0.19**

PEI's main natural resource – wind – is strongest along the coast at the eastern and western ends of the Island. Wind generation is almost always built at utility-scale levels due to economies of scale and ease of maintenance. The proposed Eastern Kings Wind Phase 2, scheduled to be online in Q3 2021, is expected to increase Maritime Electric's proportion of energy supply from on-Island wind to 30 per cent. The Energy Corporation is considering another windfarm in 2025 that will increase this percentage even further.

The Island's solar resource is relatively consistent across the province[4]. Primary considerations for locating a utility-scale solar facility include land availability and proximity to existing transmission infrastructure. Provincial governmental subsidies have increased

[3] https://www.cer-rec.gc.ca/nrg/sttstc/lctrct/rprt/2017cndrnwblpwr/prvnc/nb-eng.html?=undefined&wbdisable=true
[4] https://www.nrcan.gc.ca/18366

the popularity of residential roof-top solar, which without subsidies has a unit cost of produced energy much higher than that of utility-scale solar.

Table 2 Residential Rooftop and Utility Ground-Mounted Solar Costs				
Description	**Typical Size**	**Unsubsidized Installed Cost**	**Annual Output[5]**	**$/kWh Output**
Residential Rooftop	10 kW	$30,000	11,000 kWh	$2.72
Utility Ground-Mounted	10,000 kW	$17,000,000	11,000,000 kWh	$1.54

Maritime Electric's oil-fired generation located on-Island does not provide appreciable amounts of energy. It is located close to load centres and existing key transmission hubs primarily to address system reliability, as it is used for both maintenance and contingency purposes.

Locating future generation on-Island will also have to consider climatic changes such as sea level rise and storm surges. The Charlottetown Plant site, located on the Charlottetown Harbour waterfront, may be impacted by storm surge levels in the next 100 years, as detailed in a Coldwater Consulting Ltd. Study for the Charlottetown Area Development Corporation[6]. The site can be modified to make it more prepared for the anticipated sea level rises.

Severe climatic events such as high winds and ice storms are the biggest threat to transmission and distribution infrastructure, as little of this is located in potential flood zones. The Company has been reviewing its design standards with an eye to system hardening.

Sustainability

Sustainability is the ability to meet our own needs today without compromising the ability of future generations to meet their needs. Maritime Electric holds this as a core value, and emphasizes social, economic and environmental sustainability in its everyday business.

Maritime Electric understands its impact on the provincial economy, and providing customers with good value for their electricity dollar is key to continued prosperity on the Island. This means ensuring on-Island renewable energy is supplied at competitive rates, securing reasonably-priced energy and capacity from the mainland, and being mindful of the impact of carbon pricing on the overall energy supply.

Security of supply also impacts decision-making as Islanders become more reliant on electricity for space heating and transportation. PEI has limited natural resources and is connected to the mainland via one transmission corridor. Mainland supply interruptions leave Islanders exposed, and dispatchable diesel-fueled generation located on-Island will ensure that supply interruption is minimized. That said, Maritime Electric is cognizant of its environmental responsibilities, particularly as they contribute to global warming. On-

5 Assumes ideal orientation, which is done with utility-scale projects but often not with residential rooftop. Based on 1,100 kWh/kW annual production. Assumes zero panel output degradation.

6 Charlottetown Waterfront Assessment, Coldwater Consulting Ltd., 2016

Island diesel generation is intended to operate sporadically, and only when necessary. The fuel usage is relatively low compared to the benefits of locating such infrastructure on-Island.

Maritime Electric is purchasing its first all-electric vehicle in 2020, and has trialed a battery-operated line truck boom that will reduce engine idling. Further electrification of the vehicle fleet is only a matter of time as electric vehicles become more economic and vehicle ranges increase.

Maritime Electric holds the safety of its employees and the public as paramount. In addition, it strives to provide a health-conscious, inclusive and diverse workplace. Communications with the public, and engagement with our customers, will help Maritime Electric navigate the upcoming climatic changes and technological advancements that will be seen in the electricity industry.

5. EMERGING TECHNOLOGIES

Society's pace of technological change has been rapid over the past 20 years. The electric utility business will face this same rapid change over the next 20 years, and technology will change the way the Company undertakes its business. Energy will still be supplied to customers over the Company's transmission and distribution lines. Field crews will still be needed to construct, maintain and repair infrastructure. Some customers will still want to talk to people, not machines, when they contact the Company to discuss their service.

However, where the energy is produced and potentially stored, how these complex systems are controlled, how system maintenance decisions are made and implemented, how vegetation management is undertaken, and how the Company communicates with its customers will all be fundamentally different. The Company is already seeing that advances in mobile communications has increasingly led to digital interactions with Customer Service and Communications. The Company must be in a position to connect with its customer in the way the customer requires. These technological changes will not take place overnight, and the Company will implement them as their value and economic benefit to ratepayers come into focus.

Demand side management ("DSM") will likely be used through a variety of methods, including time of use rates, customer load control, and automatic timers, to suppress peak load growth, ensuring more efficient use of the existing system facilities. Smart meters and their associated communications systems will help the Company better monitor outages and customer usage patterns. Distribution automation will help improve system reliability by speeding up system restoration after a contingency. Energy storage – from utility-scale down to household and vehicle batteries – will provide a means to store renewable energy for later use. Data analytics will be needed to process the vast quantities of data being gathered by the Company and ensure its decisions are based on fact and experience.

Residential battery energy storage is increasing in popularity as industry developments in Lithium-ion ("Li-ion") chemistries and technologies mature, and battery prices drop as the market is established. Energy storage via Li-ion batteries is most efficient for customers when time of use rates are employed on the grid, as stored renewable or off-peak generation can be released to reduce peak load usage and costs. The payback period of Li-ion energy storage where time of use rates are in place is shorter than for a system where flat rates are used. Installation of household battery storage in other regions such as California[7] is made attractive by government incentives or rebate programs to the customer that partially cover the cost of full installation. No such programs are available within PEI, which will slow local adoption of Li-ion batteries until prices drop further. Some customers see a brief benefit during contingency situations when their supply from MECL is temporarily lost. Charging the batteries and regulating usage is required until MECL supply can be restored. Residential battery energy storage requires further technological development and incentives before widespread adoption occurs.

Cybersecurity for both the operating network as well as the Company's internal IT network is vitally important to system security and customer privacy. The Company must allocate significant effort and resources to ensure its systems remain secure.

6. SYSTEM USAGE FORECAST

Maritime Electric's energy and peak demand forecast is updated annually, providing the basis for the Company's generation, energy supply and transmission system planning requirements. Maritime Electric's annual peak demand and energy usage since 2010 are shown in Table 3.

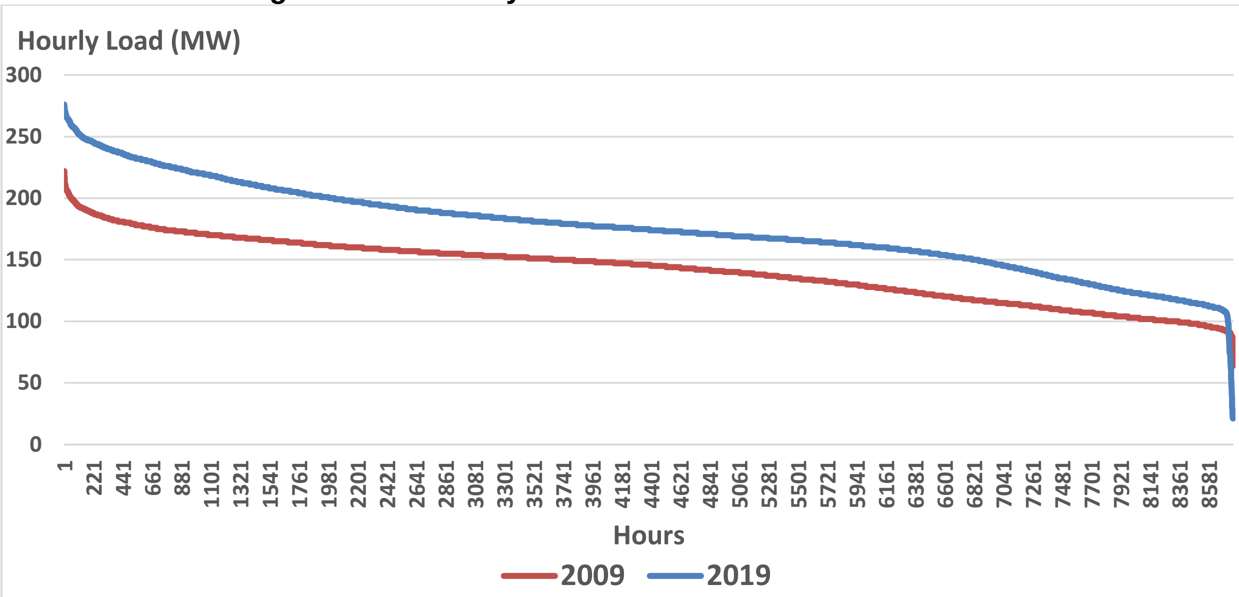
Table 3
Annual Energy and Peak Demand 2010 - 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MECL Energy (GWh)	1,115	1,132	1,165	1,214	1,256	1,279	1,282	1,298	1,349	1,385
Island Energy (GWh)	1,238	1,259	1,298	1,350	1,195	1,424	1,424	1,443	1,494	1,531
Island Winter Peak (MW)	206	223	228	252	255	264	264	278	280	275
Island Summer Peak (MW)	190	183	194	196	195	205	200	200	220	227

The Island's load duration curve, which shows each hourly load during the year in descending order, is shown in Figure 2. It helps illustrate the system's shift in both energy and demand requirements over time.

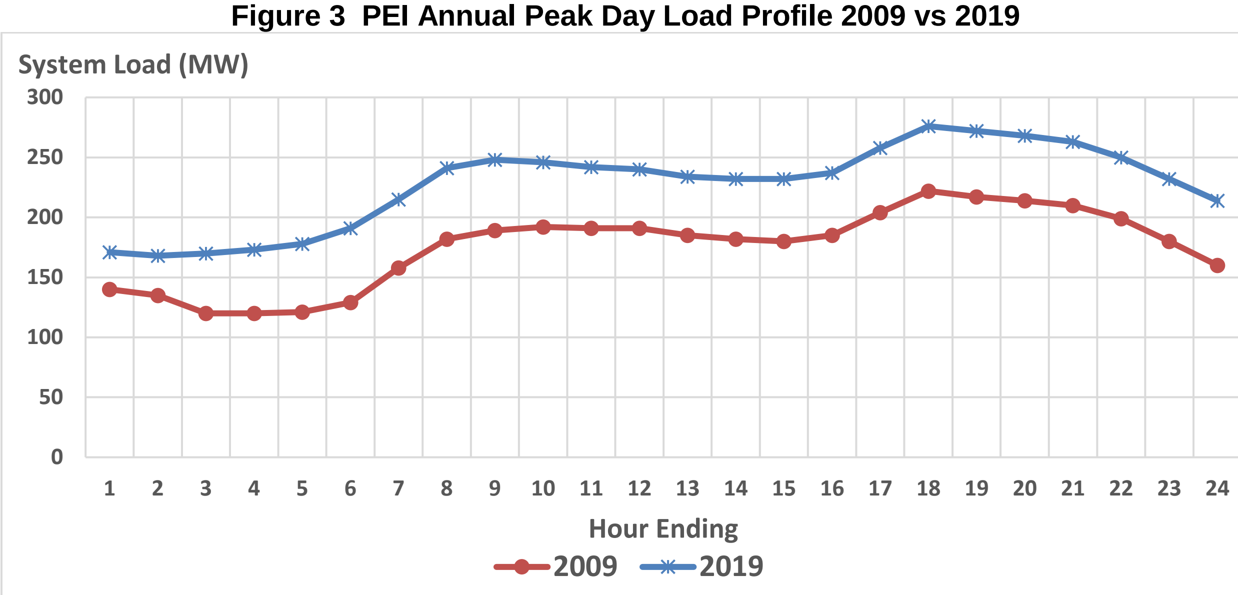
[7] https://www.cpuc.ca.gov/sgip/

Figure 2 PEI Hourly Load Duration Curve 2009 vs 2019



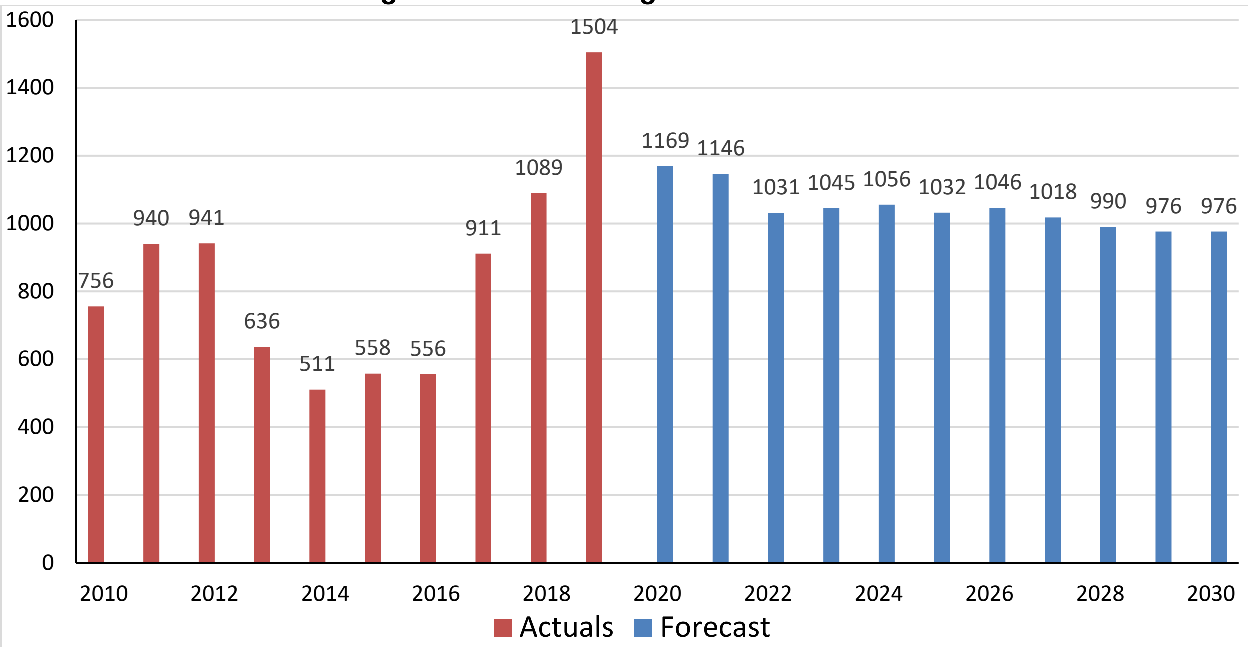
Recent annual increases in both energy and peak demand can largely be attributed to the electrification of space heating. There have been over 4,000 heat pumps installed annually over the past several years, and efficiencyPEI estimates over 20,000 have been installed in the past decade. efficiencyPEI incentives for high-efficiency heat pumps have been one of the drivers of this energy supply shift, and efficiencyPEI predicts this trend will continue in the short to medium term. While the overall trend of the daily peak has remained constant over the past decade, the space heating load has caused a slight but noticeable flattening of the overnight low load period.

Figure 3 PEI Annual Peak Day Load Profile 2009 vs 2019



New residential construction currently installs mostly electric-based space heating for both single- and multi-dwelling buildings. Mini-split heat pumps are often the primary heat source, with electric baseboard as backup. Maritime Electric estimates that 90 per cent of semi-detached and 80 per cent of detached new housing starts install electric space heating as their primary source. Residential housing starts are forecast to remain strong for the coming decade.

Figure 4 PEI Housing Starts 2010-2030



While electrified transportation has not yet had noticeable impacts on the system, it is forecast to have a sizable impact in the longer term.

Table 4 PEI Electric Vehicle Forecast						
	Dunsky forecast of EVs in NB[8]		**Corresponding forecast for PEI**			
Year	**Per CBC News Article**[9]	**Interpolation**	**Population-based pro rata EV number for PEI**[10]	**Annual Gasoline displaced (millions of litres)** [11]	**Annual electricity for charging (GWh)** [12]	**Maximum Peak Impact (MW)** [13]
2019	320	320				
2020		1,000	200	0.3	0.6	1.2
2021		2,000	400	0.6	1.2	2.4
2022		4,000	800	1.2	2.4	4.8
2023		6,000	1,200	1.8	3.6	7.2
2024	10,000	10,000	2,000	3.0	6.0	12
2025		15,000	3,000	4.5	9.0	18
2026	20,000	20,000	4,000	6.0	12.0	24
2027		27,500	5,500	8.3	16.5	33
2028		35,000	7,000	10.5	21.0	42
2029		42,500	8,500	12.8	25.5	51
2030		50,000	10,000	15.0	30.0	60
2031		57,500	11,500	17.3	34.5	69
2032		65,000	13,000	19.5	39.0	78
2033		72,500	14,500	21.8	43.5	87
2034	80,000	80,000	16,000	24.0	48.0	96

The projected 2034 energy and demand figures equate to 3.1 per cent and 34.9 per cent, respectively, of PEI's 2019 annual energy and peak demand figures. Maritime Electric expects that incremental energy sources needed for electric vehicles will be relatively easy to acquire. Accommodating EV peak demand impacts will be more costly, although it will be tempered through customers' diverse charging patterns and system DSM measures. EV penetration will be quicker if governmental purchase or ownership incentives are put in place.

The Energy Corporation has direction and control of DSM programming through its efficiencyPEI office. Maritime Electric receives programming details from efficiencyPEI and inputs those DSM impacts into its energy and peak demand forecasts.

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8 2019 Dunsky Energy Consulting report commissioned by NB Power
9 January 7, 2020 CBC News article "NB Power could energize electric car sales for $20M"; cbc.ca/news/canada/new-brunswick/nb-power-electric-vehicle-fast-charging-stations-report-1.5417102
10 PEI has roughly one-fifth the population of NB.
11 Assumes annual driving distance of 15,000 km/yr; average mileage of 10 L/100 km
12 Assumes 2 kWh of electricity replaces 1 litre of gasoline
13 Assumes all vehicles charging simultaneously using Level 2 chargers (6.0 kW)

Table 5 Energy and System Peak Forecast 2020 - 2030											
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
MECL Energy (GWh)	1,443	1,489	1,525	1,560	1,593	1,625	1,656	1,688	1,720	1,752	1,782
Island Energy (GWh)	1,596	1,646	1,687	1,725	1,762	1,798	1,832	1,868	1,903	1,939	1,972
Island Winter Peak (MW)	294	304	312	321	329	337	345	353	361	368	374
Island Summer Peak (MW)	223	226	230	233	237	240	243	247	250	254	257

7. GENERATION RESOURCE ADEQUACY

Generation is ideally located close to a load centre for a) enhanced supply reliability and b) lower system losses. The Island's main load centres are Charlottetown and Summerside.

The majority of the Island's energy supply is procured off-Island since the Island's only economic generation source – utility-scale wind – is intermittent. On-Island dispatchable generation is required to ensure continuous customer service in the event of system restrictions both on- and off-Island. Dispatchable generation is generation where the amount of fuel delivered to the generator can be controlled, which in turn controls the output from the generator. Non-dispatchable generation, such as wind and solar, is generation where the fuel supply cannot be controlled, and consequently energy is provided to the system when the fuel is available, not necessarily when the energy is required by the system.

The interconnection agreement between Maritime Electric and New Brunswick Power was developed in 1977 when Cables #1 and #2 were installed, and stipulates that Maritime Electric carry sufficient generating capacity to meet its peak hour projected load, as well as a 15 per cent planning reserve. It also dictates that a single generating unit cannot account for more than 30 per cent of Maritime Electric's total generating capacity portfolio.

While Maritime Electric has a 15 per cent planning reserve requirement, NB Power and NS Power each provide for a 20 per cent generation planning reserve. Experience has shown that providing this level of planning reserve enables the Maritimes Area to meet the Northeast Power Coordinating Council ("NPCC") generating resource adequacy criterion that the probability of having to shed firm load due to insufficient generating capacity will be no more than one day in ten years. An operating reserve requirement is that the Maritimes Area (consisting of NB, NS, PEI and northern Maine) must be able to replace the unplanned loss of the output of the largest generator in the Area (which is usually the 660MW Point Lepreau unit) within 10 minutes. This responsibility is shared by the electric utilities on an adjusted load ratio basis.

7.1. Planning Criteria

Maritime Electric's generating capacity obligations are summarized in Table 6.

Table 6 Maritime Electric Generating Capacity Obligations		
Type	**Threshold**	**Comment**
Planning Capacity	Maritime Electric forecasted peak load, less interruptible load, plus a 15 per cent planning reserve	Ensure sufficient margin in Maritimes to accommodate loss of the largest generating unit, and still supply all customer load. Takes into account minor customer load variations. A portion of wind nameplate capacity is included, based on a probabilistic analysis.
Contingency (PEI)	Supply customer load for restrictions in off-Island supply, as well as on-Island transmission system issues	Strategically located to backup both on- and off-Island system contingency events.
Operational Requirements	Maritime Electric annual peak instantaneous load; typically 1-2 per cent higher than annual peak hour average load	Required to supply Maritime Electric load for worst-case single contingency even if wind unavailable.
Ancillary Services	Spinning and non-spinning reserve, reactive power supply	Required to meet Maritime Electric obligations under Island Open Access Transmission Tariff ('OATT').

7.2. Existing Resources

Maritime Electric's generation requirements are served by a combination of off- and on-Island facilities.

7.2.1. Off-Island Supply

Maritime Electric sourced 78 per cent of its energy supply from off-Island sources in 2019, including 16 per cent from a long-term participation stake in NB Power's Point Lepreau Nuclear Generating Station, and the rest through an all-services energy purchase agreement ("EPA") with NB Energy Marketing ("NBEM"). The current EPA expires in 2024.

The energy purchased through the EPA is commonly referred to as 'system purchases', since NBEM supplies Maritime Electric from a variety of sources. These may be located in New Brunswick, Nova Scotia, Quebec or the United States and are transported to the Island via New Brunswick and its connections to its neighbours. Better load predictability leads to more favourable energy prices when procuring energy supply contracts.

Point Lepreau

The Point Lepreau Unit Participation Agreement provides Maritime Electric with 30 MW (29 MW at Murray Corner net of transmission losses in New Brunswick) of base load capacity and associated energy from Point Lepreau. That facility has a capacity of 660 MW, and incorporates Atomic Energy of Canada Limited's CANDU technology. The Participation Agreement is for the life of the plant, which is expected to be in service until at least 2039.

7.2.2. On-Island Dispatchable Fossil Fuel Based Generation

Table 7
Dispatchable Generation Assets

Name	Location	Owner	Size (MW)[14]	Vintage	Comment
CTGS 9	Charlottetown	Maritime Electric	20	1963	Oil-fired thermal generation. Approved for decommissioning as of January 1, 2022. Presently in long-term layup.
CTGS 10	Charlottetown	Maritime Electric	20	1968	Oil-fired thermal generation. Approved for decommissioning as of January 1, 2022. Presently in long-term layup.
CT1	Borden	Maritime Electric	15	1971	Combustion turbine; quick start.
CT2	Borden	Maritime Electric	25	1973	Combustion turbine; quick start.
CT3	Charlottetown	Maritime Electric	49	2005	Combustion turbine; quick start.
#3-#9	Summerside	Summerside	15	1950-2015	Reciprocating engines – diesel fueled

Charlottetown Thermal Generating Station (CTGS)

Maritime Electric owns and operates the CTGS which is fueled by heavy fuel oil (bunker C). Its capacity has varied throughout its existence, reaching 65 MW in 1968 with the installation of Unit 10. The current CTGS total net generating capacity is 38 MW (CTGS 9 and 10 have a gross rating of 20 MW each but the plant net capacity is 38 MW after station service requirements are subtracted). It is currently in long term layup and will only be called upon to generate should the normal sources of supply on the mainland become unavailable for an extended period. The units must be capable of being returned to service within 90 days of notice in long-term layup.

Given its age, Maritime Electric has been limiting CTGS capital investment to items required to a) ensure the safety of personnel operating the equipment, and b) maintain the reliability of the facility in the short term. IRAC approved the decommissioning of the remaining generating units associated with the CTGS as of January 1, 2022 under Order UE19-08. Maritime Electric submitted a decommissioning plan for the CTGS building to IRAC that is still under review. For planning purposes, the generating capacity will remain at 38 MW until the end of 2021 and will reduce to 0 MW as of January 1, 2022.

[14] Maximum winter output. Summer capacity is lower for combustion turbines than winter capacity, as the summer's higher ambient temperature air has a lower density than the winter's colder air. As air density increases, combustion turbine generators output more power per unit of fuel input.

Borden Generating Station

Maritime Electric owns and operates the Borden Generating Station which consists of two combustion turbine units ("CT1" and "CT2") that burn light fuel oil (diesel). They were installed in the early 1970s and have a net combined capacity of 40 MW. The Borden Generating Station is normally in a standby mode. Because of their 10 minute start capability, the units are also used to supply Maritime Electric's share of the Maritime Area 10 minute non-spinning reserve.

CT2 has a mechanical clutch located between its turbine and generator, enabling the turbine and generator to disengage and allowing the generator to operate as a synchronous condenser. This provides voltage conditioning and support to the Island transmission system without requiring diesel fuel usage (except to get the unit up to speed).

The Borden Generating Station has been refurbished and upgraded in recent years, and is expected to operate until the end of the decade when it is scheduled to be decommissioned.

Combustion Turbine 3 – Charlottetown Plant

Maritime Electric owns and operates the CT3 combustion turbine generator which is fueled by light fuel oil and is located at the Charlottetown Plant. It was installed in 2005 and has a net capacity of 49 MW (the gross output is 50 MW; 49 MW is the output delivered to the system after subtracting the unit's station service). CT3 is normally in standby mode, and operates either when the flow of purchased energy is interrupted by outages of other generators, or during transmission system element failure or maintenance. CT3 is also used to supply energy during curtailments from New Brunswick, when wind output is less than forecast, or when Island load exceeds scheduled energy deliveries, and can supply 10 minute non-spinning reserve because of its 10 minute start capability.

7.2.3. On-Island Utility-Scale Wind Generation

Maritime Electric has agreements with the Energy Corporation to purchase all of the output from a number of Island-based wind farms.

Table 8
Wind Generators Under Contract

Name	Location	Size (MW)	Vintage
North Cape Phase 1	North Cape	5.28	2001
North Cape Phase 2	North Cape	5.28	2003
Aeolus	Norway	3	2004
Engie Norway	Norway	9	2007
Eastern Kings	Elmira	30	2007
WEICan	Norway	10	2012
Hermanville-Clearsprings	Hermanville-Clearsprings	30	2014

The aggregate capacity factor of the facilities is 37 per cent. A higher wind capacity factor leads to a better wind generation output profile and lower load following costs. Maritime Electric's view is that future wind farms designated for Island load should target wind technologies that will maximize capacity factors.

The Energy Corporation is developing a new 30 MW windfarm in eastern PEI, with a planned Q3 2021 in-service date. This project will utilize gear-less wind turbines with a 45 per cent projected capacity factor. The Energy Corporation has identified another 40 MW future wind development with a potential 2025 in-service date.

Maritime Electric does not source energy from Engie's 99 MW West Cape wind farm. Energy from this facility is exported from the Island to external markets and provided to the City of Summerside. Engie pays a fee to use the Island transmission system in accordance with the OATT. These fees help offset costs paid by all other Island customers for the transmission system.

Both the Summerside and Maritime Electric (through energy purchased from the Energy Corporation) export minimal amounts of surplus wind energy. Exports typically occur in the overnight hours when external market power prices are depressed.

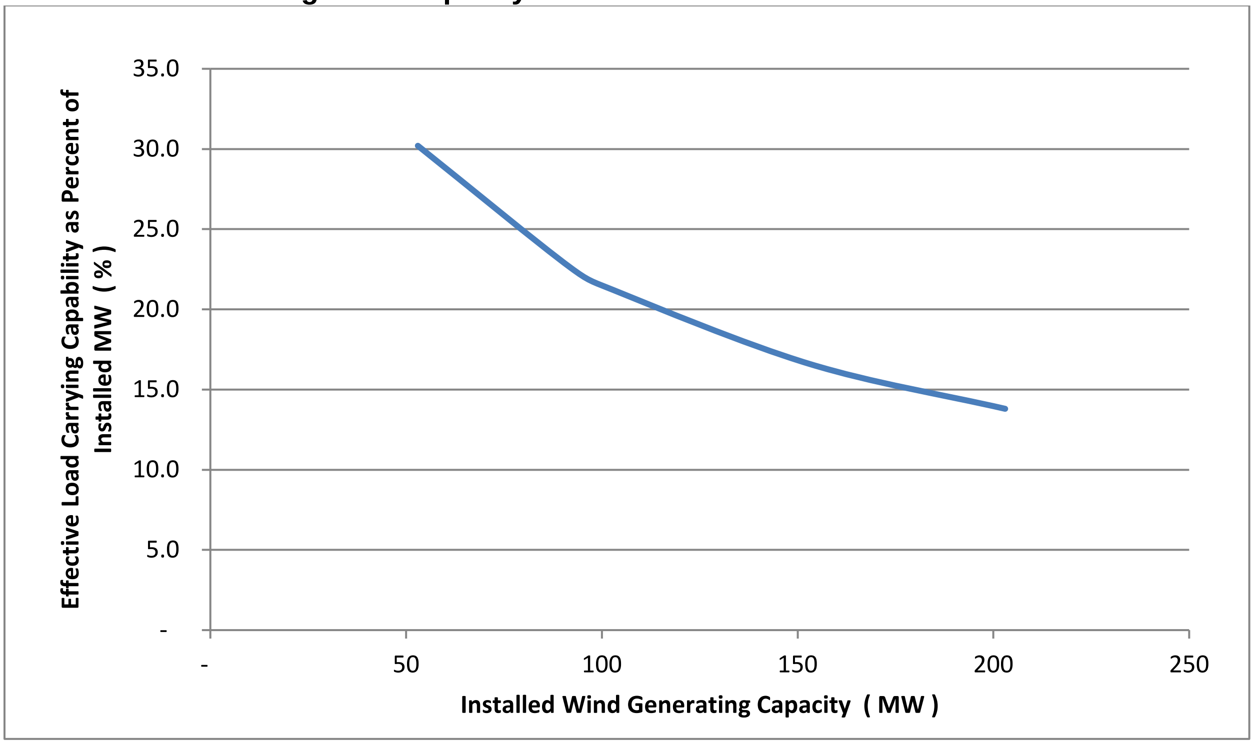
The Island transmission system can accommodate additional wind farms for export, depending on size, location and technology used. The cost to backstop the additional wind will be set by external markets since PEI has no on-Island generation that can provide the service economically.

Only a portion of the nameplate capacity of the wind generators installed in PEI is counted as planning capacity due to the intermittent nature of wind generation. Based on the electric utility industry probabilistic Loss Of Load Expectation ("LOLE") methodology, Maritime Electric has assigned an Effective Load Carrying Capability ("ELCC"), or effective capacity value, of 21 MW to the 92 MW of its contracted wind generation. The ELCC of 21 MW is the additional load that the system can supply with the 92 MW of wind generation added to the system, while still maintaining the same level of reliability of supply.

Figure 5 shows how the percentage of wind generation that can be considered as ELCC varies as the amount of wind generation installed in PEI increases. For 92 MW of installed capacity, the 21 MW of ELCC corresponds to 23 per cent of the installed capacity. Further increases in wind generation will result in a small increase in ELCC. For example, for 200 MW of wind generation, the ELCC would be approximately 14 per cent of 200 MW or 28 MW. The reason for this is that 92 MW is already a large amount of wind generation relative to the size of the PEI load. The new 30

MW windfarm to be completed in 2021 will increase the ELCC from 21 MW to 24 MW[15].

Figure 5 Capacity Value of Wind Generation in PEI



7.2.4. Utility-Scale Solar Generation

Utility-scale[16] solar generation offers advantages over small-scale solar such as increased efficiencies and lower per unit cost of installation. With similar installation costs to that of utility-scale wind but reduced capacity factors[17], utility-scale solar has a much higher per unit cost of energy produced. There are currently no utility-scale solar installations in service, however two projects will come into service in the short term: the Energy Corporation's 10 MW Slemon Park Microgrid project, and Summerside's 21 MW Sunbank project. Both of these projects have energy storage associated with the solar installation.

Solar generation can help to reduce summer peak system loading, but does not aid in reducing system peak loading. Since the annual peak load occurs during the hour ending 18:00 in December or January, solar

15 122 MW of installed wind generating capacity results in a 20 per cent ELCC, providing 24 MW of effective capacity.

16 Utility-scale refers to equipment that would cause a noticeable change in a utility's operation. A household rooftop installation would unlikely impact a utility's operation, while larger distribution-connected solar installation may, depending on size. All transmission-connected solar installations are considered utility-scale.

17 The maximum capacity factor that can be expected from a solar installation on PEI is 14 per cent versus an expected capacity factor of 45 per cent for the upcoming wind farm scheduled for operation in 2021.

generation does not reduce the amount of infrastructure required to supply electricity to Maritime Electric customers.

7.2.5. Small-Scale Renewable Energy Generation

The *Renewable Energy Act* allows customers to install generation on their premises, and enables net metering for renewable energy generation installations less than or equal to 100 kW. Roughly 500 customers had signed net metering solar agreements at the end of July 2020, totaling 4.7 MW of installed capacity. 40 per cent of these customers were added in 2020, mainly in response to the Province's solar incentive program[18]. Prior to the program there was a total of 2.2 MW of customer installed solar generation registered under the net metering program, and between August 2019 and July 2020 a total of 2.5 MW of solar was added to the program. This amount of solar generation offsets roughly 0.33 per cent[19] of Maritime Electric's annual energy purchases. The Province has publically specified neither a target capacity nor a timeframe on this incentive program.

The cost to install solar energy has reduced significantly over the past number of years, and is currently in the $3.00-3.50 per watt range[20]. It is a useful energy source but does not provide supply when power to the customer is lost, and the customer requires a backup regulating source – generation or a battery supply – in order for the solar generation to work during power outages.

Table 9 shows that continued addition of net metered solar generation will lead to noticeable cost shifting from customers with net metered solar to customers without net metering.

Table 9 Solar Net Metering Cross Subsidization	
Average Installation Size	9 kW
Assumed Solar Capacity Factor	14 %
Annual Output per Residential Net Metering Installation	11,000 kWh
Difference Between Residential First Block Energy Charge and Avoided Cost	6 cts/kWh
Annual Reduction in Contribution towards Fixed Costs, per Installation - (11,000 kWh) x (6 cts/kWh)	$660/yr
Number of Installations to Cause 1 Per cent Rise in Bills Due to Cross Subsidization - ($2 million) / ($660/customer per year)[21]	3,000

Customers who install renewable energy generation systems over 100 kW are reimbursed for energy delivered to the grid at a rate equal to Maritime

18 https://www.princeedwardisland.ca/en/information/transportation-infrastructure-and-energy/solar-electric-rebate-program
19 Based on 2019 annual energy purchases
20 Range provided by efficiencyPEI based on applications to their Solar Electric Rebate program
21 Maritime Electric annual revenue requirement is approximately $200 million. A 1 per cent reduction in revenue ($2 million) would lead to a 1 per cent rise in bills to cover the shortfall.

Electric's avoided energy cost, which is currently in the 8 cents/kWh range. This difference in reimbursement[22] acts as a disincentive to customers installing solar systems above 100 kW.

7.2.6. Capacity and Ancillary Services

Maritime Electric's on-Island generating assets use oil-based fuel and are uneconomic to dispatch in a competitive electricity market. They are used primarily for backup and emergency purposes. However, the capacity and other ancillary services associated with Maritime Electric's generators can be attributed towards Maritime Electric's requirements.

Decommissioning of the CTGS units will leave Maritime Electric with 89 MW of dispatchable generation in 2022, which represents 29 per cent of its projected capacity requirement. Additional generation required by Maritime Electric for capacity, ancillary services or energy will have to be provided by off-Island sources unless on-Island dispatchable generation is added.

7.2.7. Maritime Electric Short Term Purchases of Generating Capacity

Maritime Electric is currently purchasing system capacity and system energy from NBEM under a contract that extends to February 29, 2024. Generating capacity reservations, and the associated transmission capacity to deliver the product to PEI, must be purchased on a yearly basis such that the purchased capacity plus the Maritime Electric owned capacity is more than the peak load projected for the year. Without the generating capacity, system energy cannot be purchased. The system energy purchases are not tied to any particular generating units on NB Power's system. Beyond February 29, 2024 there is uncertainty about the availability and pricing for purchased capacity. NB Power appears to be the only entity in the region that will have surplus generating capacity.

NB Power's main alternative to the sale of generating capacity to Maritime Electric appears to be the ISO-NE forward capacity market and its associated annual forward capacity auctions ('FCA'). However, the north-to-south transmission transfer capacity between New Brunswick and New England is constrained. In addition, Maritime Electric's EPAs with NBEM have been for multi-year terms, while the ISO-NE FCAs are held annually. For these reasons the FCA results should be viewed as indicative, and not determinative, for pricing of capacity purchases under Maritime Electric's EPA with NBEM.

[22] Maritime Electric net metering customers on a residential rate currently offset energy charges of $0.1437/kWh when surplus energy credits to offset future usage.

Table 10 Recent New England Forward Capacity Market Results						
		FCA 10	FCA 11	FCA 12	FCA 13	FCA 14
Date Forward Capacity Auction held		Feb 2013	Feb 2016	Feb 2017	Feb 2018	Feb 2019
Supply obligation period		June 2016 to May 2017	June 2019 to May 2020	June 2020 to May 2021	June 2021 to May 2022	June 2022 to May 2023
For the New Brunswick interface:						
- capacity transfer limit	MW	700	700	700	700	700
- less tie benefits	MW	519	500	506	516	501
- transmission transfer capacity	MW	181	200	194	184	199
- capacity supply obligations	MW	181	200	194	184	72
- payment rate	$US/kW-month	4.000	3.381	3.155	2.681	2.001
For most of New England:						
- payment rate	$US/kW-month	7.030	5.297	4.631	3.800	2.001

Maritime Electric's understanding for the lower generating capacity prices at the New England/New Brunswick interface is that the New England Independent System Operator ("ISO-NE") has assigned most of the transfer capacity on the New England/New Brunswick interface to "tie benefits" (support that the Maritimes Area can provide to New England in the event of a system disturbance in New England). This has resulted in limited ability for entities in the Maritimes Area (and Quebec) to participate in the New England Forward Capacity Market. In recent auctions, this historical difference in market prices has disappeared and the latest FCA 14 resulted in pricing parity between ISO-NE and the NB External Node. Although the pricing disparity has disappeared, the price for additional capacity at the NB External Node continues to drop. FCA 14 resulted in a cost of 2.001 USD/kW-month which is half of the cost from FCA 10 in 2016.

Maritime Electric has taken advantage of the surplus generating capacity in New Brunswick by receiving lower New Brunswick capacity pricing to fulfill its short term capacity requirements. NB Power is forecasting that its capacity reserves will dwindle due to New Brunswick load growth as well as infrastructure retirements, as it states "the need for capacity will outstrip the resources starting in the 2027 time frame."[23] NB Power may have insufficient surplus generating capacity available to meet Maritime Electric's needs within the next EPA contract timeline.

[23] NB Power 2017 Integrated Resource Plan, page 33, second paragraph. The year that NB power will run out of surplus generating capacity may change due to a revised plan for the Mactaquac Hydro Facility refurbishment. NB Power is considering refurbishing one or two turbines at a time instead of all six units at once. Increased pressure from the Federal Government to retire coal generation could impact the lifespan of Belledune Generating Station.

Transmission constraints are a second source of uncertainty around the extent to which Maritime Electric can rely on short term purchases of generating capacity from New Brunswick. In recent years there has been strong load growth in the southeastern part of New Brunswick, particularly in the Moncton area. This has increased the loading on the transmission lines that supply southeastern New Brunswick, which includes PEI load, because there are no generating plants in southeastern New Brunswick. When a main transmission line to the Moncton area goes out of service, deliveries to PEI are under the threat of curtailment.

Firm transmission across the NB-NS/PEI interface was limited to 80 MW in early 2015, all of which was reserved for Maritime Electric. NB Power has since determined that the maximum firm interface transfer capacity is 300MW, based in part on transmission system upgrades completed in 2016 and 2017.

Table 11
Firm Transmission Capacity in New Brunswick to NS/PEI Interface

	MW	Expiry date	Comment
Maximum available during before 2015			
- Maritime Electric Dalhousie participation	20	Jan 1, 2025	Held by Maritime Electric
- Maritime Electric Point Lepreau participation	30	Jan 1, 2030	Held by Maritime Electric
- 25 year Maritime Electric International Power Line commitment	30	Dec 1, 2032	Held by Maritime Electric
Pre-2015 Subtotal	**80**		
Additional made available after 2015			
- Assigned to NBEM for Maritime Electric due to prior request	50	July 1, 2031	Held by NBEM
- Awarded to NBEM in Aug 2016 through Open Season	70	2100	Held by NBEM
- Awarded to NBEM in Feb 2017 through Open Season	100	2100	Held by NBEM
2015-Present Subtotal	**220**		
Total Available	**300**		

130 MW of this 300 MW is reserved for serving Maritime Electric load. 30 MW is required for delivery of the Company's 30 MW participation in Point Lepreau, leaving 100 MW for delivery of off-Island purchased generating capacity through Maritime Electric's dedicated capacity. The remaining 170 MW is currently assigned by NBEM to Maritime Electric and Summerside. There is no long-term assurance that Maritime Electric will be able to contract for a portion of this 170 MW.

Maritime Electric also purchases approximately 6 MW of spinning reserve on an on-going basis to provide for its share of the Maritime Area spinning reserve requirement. Spinning reserve normally can only be supplied by dispatchable generating units that are running but not fully loaded.

7.3. Identification of Needs

Maritime Electric must ensure that it has sufficient resources owned or under contract, both on- and off-Island, to ensure it can reliably supply energy to its customers and at the same time meet its capacity obligations. Resources are required for a) energy supply, and b) capacity and other ancillary services.

7.3.1. Energy and Capacity Supply

Table 12 includes a detailed breakdown of Maritime Electric's load forecast for the period 2020 to 2025. Maritime Electric represents 90 per cent of the PEI electricity load, with the remaining 10 per cent supplied by Summerside, which obtains its energy supply from sources other than Maritime Electric. Approximately one-third of the forecast growth in electricity sales is expected to be due to growth in residential space heating.

Table 12 Detailed Maritime Electric Load and Peak Forecast								
	Actual		Forecast					
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Heating Degree Days	2,911	2,920	2,760	2,760	2,760	2,760	2,760	2,760
Maritime Electric electricity sales growth (%)	4.1	2.4	4.4	3.2	2.4	2.3	2.1	2.0
Maritime Electric electricity sales (GWh)								
- Residential non space heating	449	462	472	484	494	504	514	523
EV charging	0	0	1	1	2	4	6	9
- General service + Sm Industrial	493	491	507	523	538	553	566	577
Subtotal non space heating	942	953	980	1,008	1,035	1,061	1,086	1,109
- Residential space heating	164	179	184	199	214	229	244	258
- Maritime Electric transmission voltage	152	155	185	193	193	193	193	193
Subtotal	1,257	1,287	1,349	1,399	1,442	1,482	1,522	1,560
- DSM impact on Residential			(3)	(6)	(10)	(14)	(17)	(21)
DSM impact on General Service			(3)	(7)	(12)	(17)	(22)	(27)
Total	1,257	1,287	1,343	1,386	1,420	1,452	1,483	1,512
Energy supply requirement (GWh)								
- Add Maritime Electric company use	2	2	2	2	2	2	2	2
- Add system losses (6.8%)	90	96	98	101	104	106	108	110
Net Purchased & Produced Total	1,349	1,385	1,443	1,489	1,525	1,560	1,593	1,625
System Peak Load Factors								
- Non space heating loads	0.64	0.59	0.62	0.62	0.62	0.62	0.62	0.62
- Maritime Electric transmission voltage	0.99	0.87	0.91	0.90	0.94	0.94	0.94	0.94
Maritime Electric Peak Load (MW)								
- Non space heating loads	167	185	181	186	191	196	201	205
- Residential space heating loads	59	44	63	68	73	78	83	87
- Maritime Electric transmission voltage	18	20	23	23	23	23	23	23
Subtotal	**243**	**250**	**268**	**278**	**288**	**297**	**307**	**316**
- DSM impact on Residential			(1)	(2)	(3)	(4)	(6)	(7)
DSM impact on General Service			0	(1)	(2)	(2)	(3)	(3)
Total	**243**	**250**	**267**	**275**	**283**	**291**	**299**	**306**
Temperature at 17:00	(10.2)	(5.3)	(9.0)	(9.0)	(9.0)	(9.0)	(9.0)	(9.0)
Date	Dec 27	Dec 16						

The annual system peak load historically occurred during the middle two weeks of December after sundown, between the hours of 17:00 and 18:00. The peak was driven primarily by lighting loads, including holiday lighting. With increased use of electricity for space heating in recent years, Maritime Electric has observed what it expects is the beginning of a transition to a January or February system peak. This is due primarily to colder temperatures, on average, in January and February, causing the extra heating load in those months to be more than the extra holiday lighting load in December. However, this transition is expected to take some time, and for the forecast period 2020 to 2025 the system peak load is estimated as occurring at a temperature of -9.0 degrees C for the hour ending 18:00 in December.

7.3.2. Management of Existing Assets

Maritime Electric's generation assets require continuous inspection, maintenance and upgrades to keep them in reliable working condition, as well as to meet tightening environmental regulations.

The CTGS was placed in long-term layup at the end of 2018, with decommissioning scheduled to occur after January 1, 2022. The remainder of Maritime Electric's generation is combustion turbine-generator technology, where a high-speed diesel-fueled combustion turbine supplies mechanical power to an electric generator, which converts the mechanical power into electricity. Combustion turbine-generators, also known more simply as combustion turbines, have multiple systems supporting the production of electricity. A failure in any one system results in an inoperable combustion turbine.

Scheduled inspections are undertaken for Maritime Electric to meet its insurance, regulatory, legislative, and environmental obligations. Inspection frequencies vary, depending on the equipment and systems involved. Larger pieces of equipment often require less frequent, but lengthy and expensive, inspections and overhauls. Generation component lifespan is defined either by usage or time. Worn or outdated components must be replaced in order to maintain reliable unit operation and critical spare components must be sourced to limit generator downtime. Components such as the control system become obsolete after a certain amount of time as technology advances and manufacturers and secondary suppliers no longer stock replacement parts.

CT1 and CT2 are both approaching 50 years of age, and contain many components that have become obsolete over the last decade. There are a limited number of technical resources in the world capable of rebuilding some of the turbine components. These two generators are approaching the point where replacements will no longer be available, and as a result, the generators will have to be replaced due to component obsolescence. Maritime Electric is targeting replacement of these turbines in 2030. CT3 components are expected to continue to be available well into the future, and upgrades have been completed in order to keep the unit up-to-date.

7.4. Evaluation of New Generation Options

7.4.1. Locational Requirements

Generation can be located to resolve system issues as well as supply needed capacity and energy. It can help maintain service during system equipment outages, and can help delay the need to install additional transmission facilities that are needed only a few hours per year. It is most effective when located close to a major load centre as it increases customer reliability and minimizes transmission and/or distribution losses between generator and load.

CT3 is used to offload the West Royalty transformer when West Royalty substation equipment is out of service for planned or emergency maintenance, in addition to being a capacity resource that can be dispatched for Island or Maritime needs. Borden was built prior to the PEI-NB connection. While it provides capacity and ancillary services, it provides little in the way of locational benefits.

There are many factors when determining the best location to locate a new generator, as it requires a footprint sufficient for construction, operation and maintenance, fuel offloading and storage access; cooling resources, which is typically water; maintenance facilities; ease of access for equipment deliveries; access to transmission; reliable communications; and easy access for maintenance personnel. Locating generation out of the way, out of public view may be publically preferred but limits the cost-effectiveness and reliability of the generation. Use of an existing generating site, such as the Charlottetown Plant site, is usually more cost-effective than developing a new site as it already has many of the needed facilities.

7.4.2. Energy Supply

A majority of Maritime Electric's energy supply is procured off-Island, and this will continue due to a lack of an economic fuel supply available to the Island.

Table 13
Forecast Maritime Electric Energy Sources 2020 - 2025

	Actual		Forecast					
	2018 (GWh)	2019 (GWh)	2020 (GWh)	2021 (GWh)	2022 (GWh)	2023 (GWh)	2024 (GWh)	2025 (GWh)
CTGS	0	0	0	0	0	0	0	0
Combustion Turbines	3	1	1	1	1	1	1	1
Energy Corporation wind[24]	301	302	302	361	420	420	420	499
Customer-owned	2	3	5	7	8	9	10	11
Point Lepreau	216	221	215	215	215	215	215	215
NB system purchases	827	858	921	906	882	915	947	899
Total	1,349	1,385	1,443	1,489	1,525	1,560	1,593	1,625

[24] Energy Corporation assumed to commission a 30MW wind farm in Q3 2021 and a 40 MW wind farm in mid-2025

This energy supply shows no substantial change in energy generation by Maritime Electric's on-Island oil-fired generating generators during the 2020 to 2025 timeframe. In the longer term, operation will be required to provide eastern PEI voltage support as load grows. Table 14 provides a breakdown of the energy generated by the Company's combustion turbines between 2017 and 2019.

Table 14
CT Operation 2017 - 2019

	2017		2018		2019	
	Number of times	Energy Supplied (MWh)	Number of times	Energy Supplied (MWh)	Number of times	Energy Supplied (MWh)
Limit loading on submarine cables	32	2,411	0		0	
Limit import transmission below 240 MW[25]	0		5	186	0	
Curtailment by NB Power[26]	5	248	8	1,135	0	
NB Power "Hold to Schedule"[27]	13	643	10	248	16	358
Emergency energy supply to others	0		2	197	1	220
On-Island transmission backup	0		3	535	0	
Unit testing	24	2,148	25	425	28	242
Total	**74**	**5,449**	**53**	**2,724**	**45**	**820**

The installation of Cables #3 and #4 in 2017 mostly eliminated the requirement for on-Island generation to limit the import loading on Cables #1 and #2, and transmission system upgrades in 2018 NB Power removed the 240 MW limit[28] on imports to PEI. Periodic outages on the cables and transmission system may lead to infrequent combustion turbine operation to offload facilities, however the turbines will continue to be required for the remaining purposes shown in Table 14.

The New Brunswick electricity load is more than 10 times the size of the PEI electricity load and results in NB Power having access to more than enough spare generating capacity during most of the year to supply as much of the PEI load as needed. It is only during the coldest weather or for constraints on the New Brunswick transmission system that NB Power curtails some of its supply to PEI. This mode of operation, under which

25 In 2015 the firm transmission limit from NB to PEI/NS was 80 MW. A transmission system review by NB Power resulted in this firm transmission limit being increased to 300 MW. The increase required relatively small transmission system upgrades in NB and PEI. PEI was limited to 240 MW of import until its portion of the required transmission upgrades were completed in 2018.

26 Usually for transmission constraints in NB.

27 Usually for transmission constraints in NB due to on-Island wind generation being less than forecast, and CTs are run to make up the shortfall. Another reason is to avoid starting a larger unit in NB.

28 When Cables #3 and #4 were commissioned, the NB Transmission System Operator placed a temporary limit of 240 MW on NB-PEI transfers until the associated overhead line transmission work was complete.

much of Maritime Electric's energy supply is purchased on a non-firm basis, is expected to continue in the future, enabled in part by maintaining the on-Island generation and the increase in capacity of the interconnection with the addition of Cables #3 and #4. This synergy between the New Brunswick and PEI systems is beneficial to both parties. PEI gains access to the economies of scale offered by a much larger system, while New Brunswick derives revenue from out-of-Province sales which is used to lower rates for in-Province customers.

Maritime Electric is able to have a high wind penetration in its supply mix – 22 per cent in 2019 – because NB Power follows the fluctuations in wind generation as part of supplying system energy. The current EPA with NBEM includes a generation backstop fee for all new variable output renewable generation, including the 30 MW windfarm to be built in 2021, to compensate for this service.

Small-scale renewable energy generation and Maritime Electric's oil-fired generation is expected to supply less than 1 per cent of the Island's energy requirements. This means keeping existing equipment operational, as well as planning for future on-Island resources.

7.4.3. Generating Capacity Requirement

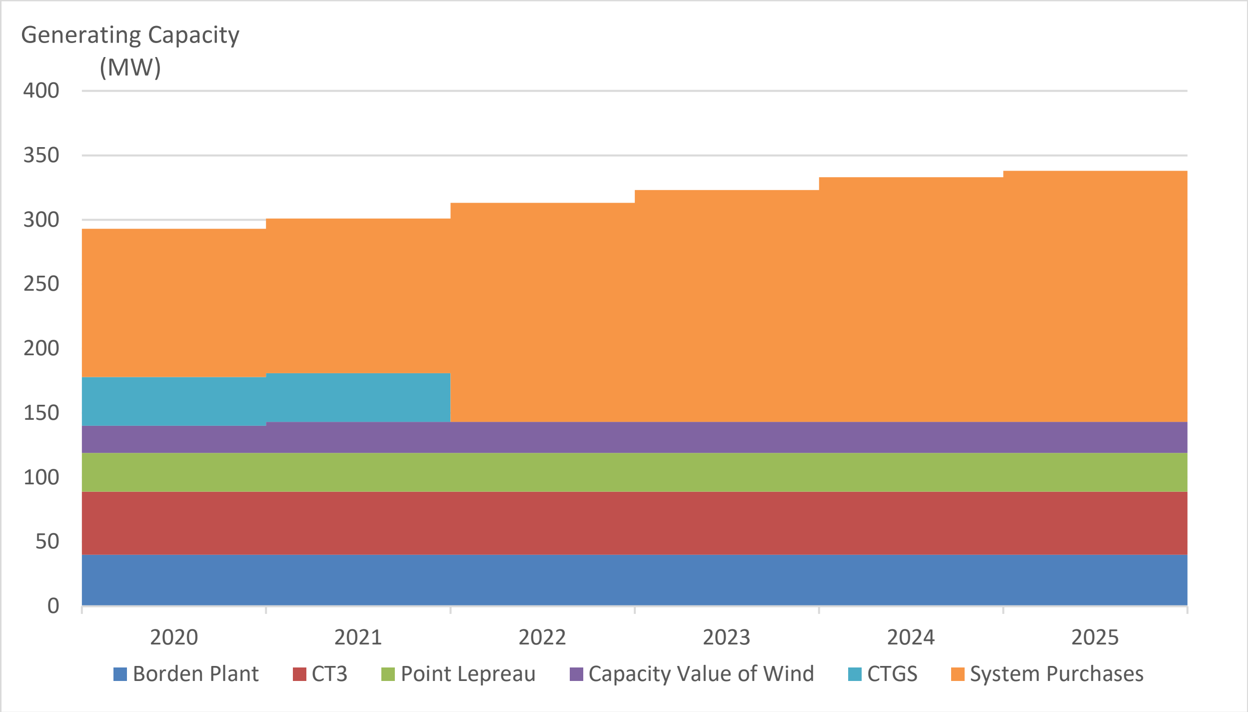
The CTGS retirement is a significant event planned during the 2020-25 period. Table 15 shows that growth in generating capacity requirement is expected to be met by increasing the amount of generating capacity purchased off-Island from NB Power on a short term basis.

Table 15 Maritime Electric Peak Load and Capacity Options								
	Actual		Forecast					
	2018	2019	2020	2021	2022	2023	2024	2025
Maritime Electric capacity requirement (MW)								
- Maritime Electric peak load	243	250	267	275	283	291	299	306
- less interruptible load	15	16	14	14	14	14	14	14
- plus 15 per cent planning reserve	34	35	38	39	40	42	43	44
Total	**263**	**269**	**290**	**300**	**309**	**319**	**328**	**336**
Maritime Electric capacity sources (MW)								
- CTGS	55	48	38	38				
- Borden Plant	40	40	40	40	40	40	40	40
- Combustion Turbine 3	49	49	49	49	49	49	49	49
- Pt. Lepreau (at Murray Corner)	29	29	29	29	29	29	29	29
- Short term capacity purchases (NB)	80	100	115	120	170	180	190	195
Subtotal	**253**	**266**	**271**	**276**	**288**	**298**	**308**	**313**
Wind								
- Maritime Electric purchased wind nameplate[29]	92	92	92	122	122	122	122	162
- ELCC as % of nameplate	23	23	23	20	20	20	20	16
- ELCC (MW)	21	21	21	24	24	24	24	26
Total	**274**	**287**	**292**	**300**	**312**	**322**	**332**	**339**
Percentage of Capacity from Off-Island Sources	**40%**	**45%**	**49%**	**50%**	**64%**	**65%**	**66%**	**66%**
Percentage of Capacity Purchased as Short-Term Capacity	**29%**	**35%**	**39%**	**40%**	**54%**	**56%**	**57%**	**58%**

Without the establishment of further on-Island dispatchable generation, the amount of short term capacity purchased off-Island will represent almost 60 per cent of Maritime Electric's supply by 2025.

[29] Assumes 30 MW windfarm added in 2021, and an additional 40 MW added in 2025.

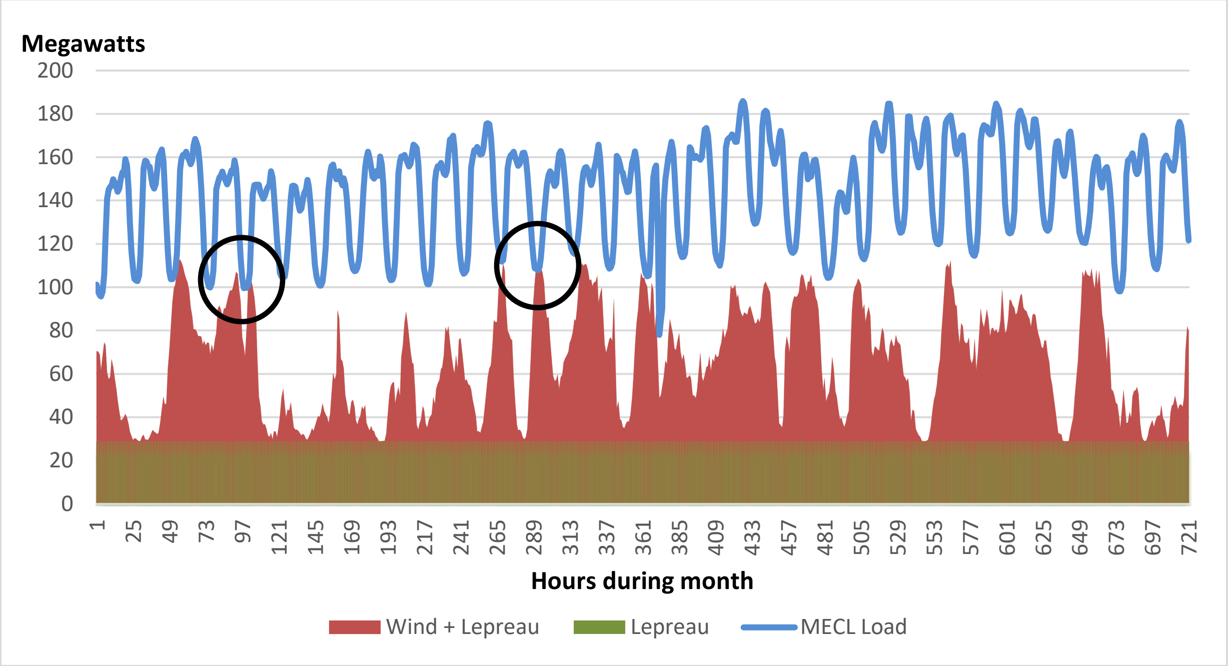
Figure 6 Maritime Electric Generating Capacity Supply



<u>Integration of wind generation</u>

Figure 7 shows how Point Lepreau and wind combine to supply a portion of Maritime Electric's load during a month. The system energy component is the area above the wind (red) line and below the load (blue) line.

Figure 7 Maritime Electric Load and Energy Supply for October 2018



The two circles illustrate periods of high wind production. When the wind generation is added to the base load generation associated with Maritime Electric's Point Lepreau participation agreement, the generation assigned to Maritime Electric surpasses the load and excess energy must be sold at the system final hourly marginal cost, which is typically lower than the wind purchase price, resulting in an energy loss cost that is absorbed by ratepayers.

Figure 8 shows the hourly system energy supply by NB Power for October 2018, and illustrates the variability in this supply that results from NB Power following the wind generation and the daily variations in the Maritime Electric load.

Figure 8 NB Power System Energy Supply to Maritime Electric for October 2018

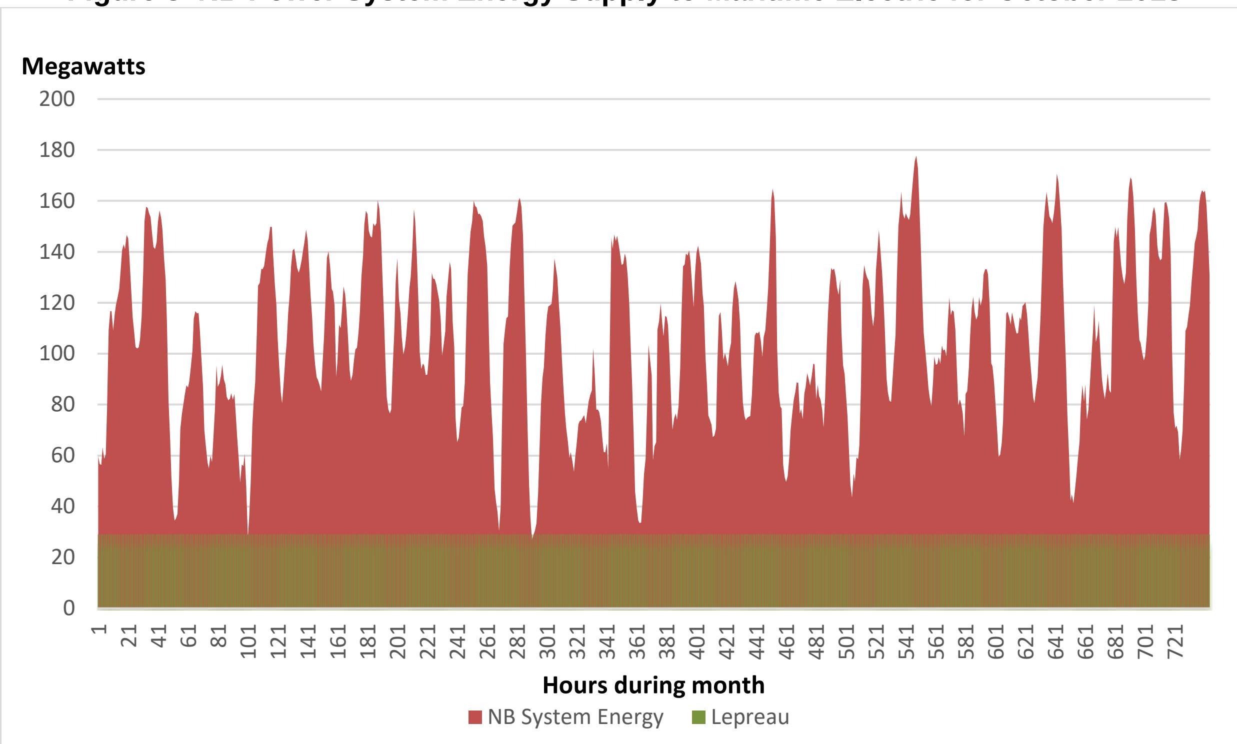
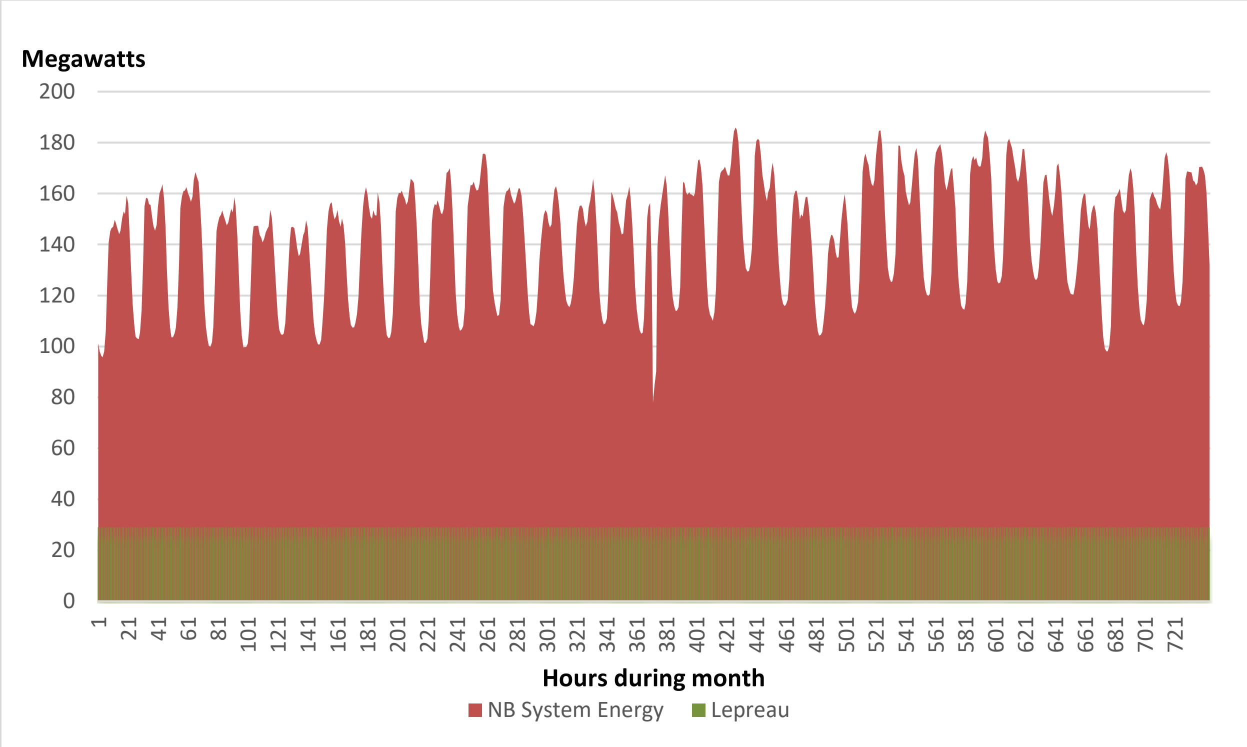


Figure 9 shows what the hourly system energy supply from NB Power would have looked like had there been no wind generation. Here the variability is due to just the daily variations in Maritime Electric's load.

Figure 9 NB Power System Supply for October 2018 if No Wind



The purpose of the three preceding figures is to show that, in addition to the limited capacity value of adding more wind generation, there is limited room under the load curve to integrate additional wind generation into the Company's energy supply. The existing wind generation under contract makes the supply of system energy by NB Power more difficult and expensive.

Transmission Impact

Maritime Electric must also plan for N-1 contingencies. The largest single generation contingency when on-Island generation is operating to support the transmission system is the loss of CT3. When Island load increases to greater than 355 MW[30], a CT3 outage (in absence of wind) means there will be insufficient dispatchable generation on-Island to support the load, and interruptible customer load will have to be shed. At levels in excess of 369 MW, both interruptible and firm customers load will have to be shed to maintain the 300 MW import level.

7.4.4. Sources of Generating Capacity

Short-Term Capacity

Maritime Electric has performed an economic analysis to compare the cost of the required system purchases to the cost of a new 50 MW combustion turbine and reciprocating internal combustion engines ("RICE") totaling 50 MW. The most cost effective means to satisfy Maritime Electric's

30 Maximum Import (300 MW) + CT1 (15 MW) + CT2 (25 MW) + Summerside (15 MW)

generating capacity requirements is to purchase short-term capacity from NBEM if it can be acquired at favourable market pricing. However, this leaves the Company's customers exposed when supply from the mainland is constrained or unavailable altogether.

Table 16
Capacity Source Cost Present Value[31]

Item	Units	50 MW CT	50 MW RICE	50 MW of Short-term Capacity
Nominal Generating Capacity	MW	50	50	50
Service Life	Years	50	40	-
Installed cost[32]	$ Million	78.3	98.4	-
Associated income taxes	$ Million	7.5	9.4	-
Annual Fixed O & M[33]	$ Million	1.1	2.4	-
Fixed O & M for 50 years	$ Million	23.9	51.3	-
Cost to replace 50 MW RICE in year 41	$ Million	-	16.8	-
Cost of Short Term Capacity Purchases	$ Million	-	-	74.8
Total	**$ Million**	**109.8**	**175.9**	**74.8**

Natural Gas-Fired Generating Project with Others
Participation in a natural gas-fired plant with others has not been recently investigated in depth due to limited availability of long term natural gas supplies in the Maritimes. The Sable Island and Deep Panuke natural gas fields off the coast of Nova Scotia both stopped producing natural gas in 2018. These fields were the main sources of natural gas production in the Maritimes, and both projects received National Energy Board approval to abandon the projects. Additions to the natural gas pipeline system in the northeastern US have not materialized due to opposition in New England. Maritime Electric is unaware of any current plans to add natural gas-fired generation in the Maritimes.

Capacity Purchases from Nova Scotia and Newfoundland
Capacity purchased from Nova Scotia would have the benefit of being on the PEI side of the transmission constraint at the NB-NS/PEI interface. However, as has been the case in the past, NS Power does not have surplus capacity to sell. Muskrat Falls in Labrador could be a source of non-firm energy supply, but not capacity. Most of the output from the Muskrat Falls hydro plant is expected to be used in Newfoundland and

31 All costs shown in Present Value, 2020$ millions
32 Capital Costs are based on a 2019 document from ISO-NE titled – Base & New England Specific Capital Costs of New Generating Technologies - https://www.iso-ne.com/static-assets/documents/2019/06/a01_capital_costs_of_new_generating_technologies.pdf
33 Fixed O & M Costs based on a 2020 document from US EIA – Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies - https://www.eia.gov/analysis/studies/powerplants/capitalcost/

Nova Scotia, and any surpluses are expected to be non-firm and available mainly during non-winter months.

Table 17 Estimated Disposition of Muskrat Falls Output	
	Average Energy (GWh)
At Muskrat Falls	4,930
At Soldiers Pond (near Holyrood) (less assumed 5 per cent losses)	4,684
Less replacement for the Holyrood Generating Station	1,956
Available for export	2,728
Delivered to Nova Scotia (less estimated 4.4 per cent losses)	2,608
Less commitments to Emera/NS Power:	
Nova Scotia block (16 hours on-peak; 365 days a year)	895
Supplemental Energy (first 5 years; winter off-peak)	240
NS Power right of first refusal on Market-Priced Energy	1,200
Available for others	273

Second 345 kV Transmission Line Between Saint John and Moncton

Recent load growth in southeastern New Brunswick, particularly in the Moncton area, and a lack of generation in this area has led to limited transmission line capacity available for PEI and Nova Scotia. Additional transmission line capacity in this area of New Brunswick could allow Maritime Electric to procure additional firm capacity off-Island.

Several initiatives over the past decade have investigated additional transmission infrastructure in the Atlantic region. One such initiative – the Regional Electricity Cooperation and Strategic Infrastructure (“RECSI”) initiative supported by NRCan – has reiterated that an additional 345 kV connection between New Brunswick and Nova Scotia provides benefits to all four Atlantic provinces.

In January 2020, Hydro Quebec and NB Power announced a study to investigate upwards of 1,150 MW of additional transmission between the jurisdictions. NS Power and NB Power announced a further study to investigate upwards of 826 MW from NB Power to NSPI and NSPI and Nalcor announced studies to investigate upwards of 500 MW between those two utilities.

Increased transmission capabilities in the magnitudes suggested by these studies should result in increased access to capacity requirements and associated energy for PEI. However, there are many hurdles to overcome before these transmission projects become reality and it will likely be 7-10 years before these lines could be fully commissioned.

Battery Storage

The first grid-scale battery storage in Canada came online in Alberta in August 2020. This 10 MW/20 MWh battery system cost $22.7 million[34]. An NREL 2020 study projects that battery system costs will decrease by 45 per cent by 2030, assuming the mid-cost projection[35]. Four hours of storage at full output appears to be the norm required in order for a battery storage system to be counted as capacity, and as such battery storage for grid operations alone is currently uneconomic based on Canadian industry costs.

A battery storage system is better suited to be included in a renewable generation project such as a wind or solar farm where the batteries can be used to limit the instantaneous fluctuations in production associated with renewable generators and allow the owner to avoid some load following costs. There are battery storage components included in the Slemon Park Microgrid and the Summerside Sunbank projects which will provide guidance into the practical applicability of this combination.

Increase Scale of Energy Efficiency and DSM Programming

efficiencyPEI's existing energy efficiency and DSM programming aims to reduce system peak by 6.9 MW over a three year period between April 2018 and March 2021. In the same period, Maritime Electric is forecasting that the system peak load will increase by 24 MW, taking into account the DSM program reductions. It is unreasonable to suggest that increasing the scale of energy efficiency and DSM programming will materially impact the need for more capacity given that Maritime Electric will still be purchasing up to 170 MW or more of short term capacity following the CTGS decommissioning.

Increased Use of Renewable Energy

Additional wind generation provides more energy, but little additional capacity value. Similarly, solar power provides solely energy into the Island system. Solar generation cannot provide capacity to the system, since the PEI annual system peak typically occurs in December or January between hour ending 17:00 and 18:00, which is after sunset.

Small-Scale Wind Energy Generation

The Island has a long history with small-scale wind generation. Several dozen customers installed small-scale wind generation on their premises in a net-metering setup between 2000 and 2010. The Province offered two incentive programs – the Community Rink Wind Program[36] and the On-Farm Renewable Energy Program[37] - to help uptake with small-scale wind.

High maintenance costs and scarcity of parts and knowledge means that few of these installations are still operating. Most wind turbine owners have

[34] https://www.energy-storage.news/news/first-grid-scale-battery-storage-project-in-alberta-canada-comes-online-thi

[35] https://www.nrel.gov/docs/fy20osti/75385.pdf

[36] Announced December 17, 2008

[37] Announced March 29, 2010

not seen a positive economic case from the machines, in large part because they cannot not keep the machines operating. The Rink Program has been abandoned, and the On-Farm program has been discontinued. Neither program turned out to be successful for the customer, Maritime Electric or the Province.

Utility-scale wind has been much more successful, since a) the equipment has a better testing regime, meaning that predicted output is much more precise; and b) installing equipment from reputable manufacturers means machines will be supported through their expected 20 year lifetime.

Small-Scale Solar Generation

Small-scale solar electricity generation has not been pursued by Maritime Electric for several reasons:

- Island solar potential is 1,116 kWh/kW[38]. By comparison, Lethbridge AB is 1,330 kWh/kW, and the state of Nevada potential is roughly 1,850 kWh/kW[39], meaning the Island's solar resource is not strong.
- Maritime Electric has not pursued solar since its high historical cost meant that it was not considered economic with other sources of energy;
- Solar provides energy but not capacity since the Island load peaks after sundown in the winter. Solar does not reduce the amount of infrastructure required to deliver energy during system peak conditions; and
- Any program that gives capacity credit to solar is cost-shifting from solar owners to all other system customers who do not install solar. In reality, it shifts costs from those who can afford to install solar (typically higher-income earners) to those who cannot afford to install solar (typically lower-income earners).[40]

Utility-Scale Solar Generation

The City of Summerside announced the new Summerside Sunbank Solar Farm and battery system in January 2020. This $69 million project will include a 21 MW solar farm and a 10 MW/20 MWh battery system, and is being funded with contributions from the Federal (38%) and Provincial (32%) governments, as well as the City of Summerside (25%) and an industry partner (5%). The system will be installed on an 80 acre property set aside for a City well field and is scheduled to be in operation in 2022.

The Province and Federal governments announced the Slemon Park Microgrid project in August 2020. This project will include a 10 MW solar

38 NRCan "Photovoltaic and solar resource maps", downloaded 26Jun2020; http://www.nrcan.gc.ca/18366; spreadsheet "municip_potentiel-potential.xlsx; Filtered for Prince Edward Island, column G, average of 'Annual' values

39 Per NV Energy website May 2, 2017. https://www.nvenergy.com/renewablesenvironment/solar/process.cfm.

40 Can Low-Income Households Afford Alternative Energy? Megan J. Maxwell; Gail Werner-Robertson Scholar, Heider College of Business, Creighton University Institute for Economic Inquiry; April 6, 2015.

farm, a 1 MW/2 MWh central battery, and some behind-the-meter battery storage at a number of locations in Slemon Park.

Utility-scale solar generation on its own does not provide generating capacity as the system peak loading occurs after sunset. The battery storage associated with a solar installation may provide an amount of capacity, depending on how the storage is used.

Small-Scale Energy Storage

WEICan completed the installation of its Battery Energy Storage System in February 2014 with a capability of 1 MW/2MWh. One of the main goals of the project was to gauge the effectiveness of a battery system storing surplus wind energy, then releasing the energy during low wind periods. The system had significant issues and the manufacturer stopped supporting the system. WEICan eventually removed the battery from operation. The Slemon Park Microgrid project will have several behind-the-meter small scale storage installations which may provide insight on cost and possible applicability on Maritime Electric's distribution system.

Hydrogen

There has been recent renewed interest in hydrogen as a way to reduce CO2 emissions. Technological advances have increased the conversion efficiencies of hydrogen fuel cells, but there are still safety concerns regarding its flammability and handling as it is still more explosive than either gasoline or electricity. It may help replace some natural gas in certain applications, and has the potential to be used as a mass storage medium for renewable electricity generation. It is being looked at to help decarbonize several sectors such as long-haul transport, chemicals, and iron and steel production.

Further technological advances will be required before it is considered safe enough to be used in passenger vehicles. Maritime Electric will continue to monitor hydrogen industry advances but does not expect hydrogen to play a role in the PEI electric system in the medium term.

7.4.5. Energy Supply while Islanded

The four submarine cables and three corresponding NB-based transmission lines connecting PEI to the mainland provide system reliability and energy supply security. Supply to the Island will be interrupted in the event of a shortage of mainland generation, a catastrophic mainland system event such as major damage to the Memramcook substation, or a southeast New Brunswick ice storm. These low risk but possible events could cause a lengthy interruption of mainland energy supply.

In the absence of wind and with the CTGS decommissioned, the three Maritime Electric combustion turbines and Summerside's diesel engines are the only dispatchable resources on-Island. Wind generation contributes energy, but little in the way of capacity, due to its intermittent nature. It cannot be relied upon minute-to-minute to produce energy. In order to accommodate load fluctuations when separated from the mainland, one generator of sufficient size must be run at a reduced rate so it can fluctuate its output to react to the load swings. In addition, it will have to accommodate the fluctuations in wind farm output. The NB-PEI interconnection enables this wind following to be undertaken by off-Island units when the connection is in service.

PEI was electrically islanded on November 29th, 2018 when a winter storm knocked out two transmission lines into the Memramcook substation, eventually overloading the remaining lines and cutting all supply from New Brunswick to Nova Scotia and PEI. It took seven hours to restore the NB-PEI interconnection and several more hours to energize all available substations on PEI[41]. Table 18 shows a potential scenario during winter periods.

Table 18
Islanded Winter Operating Scenario

Unit	Nameplate Rating (MW)	Maximum Output (MW)	Comment
Charlottetown CT3	49	35	Run at reduced output in order to allow for load and wind fluctuations.
Borden CT1	15	10	
Borden CT2	25	20	
Summerside Diesel	15	10	
On-Island Wind	202	75	Estimate of upper limit, based on system frequency response. Gusty wind conditions may lead to less wind output allowed
Maximum load served during Islanded operation		**150**	PEI's peak load in January 2020 was 287 MW.

The mid-summer output of combustion turbines at Charlottetown and Borden is lower due to temperature de-rating, and as a result less than 130 MW of load can be served during islanded operation in the summer[42]. An estimated 95 MW of Island load can be supplied during islanded operating with no wind, since more can be expected from each diesel generator when they system does not have to balance wind facility output.

A CT3 outage would leave the Island in a severe generation shortfall. With the Borden CT2 unit being the largest remaining unit, it is unlikely that the remaining diesel-powered generation could support any wind generation on the system. Additional on-Island renewable energy generation sources will not solve this due to their intermittent operation and the limited regulating capability of CT2. Dispatchable on-Island generation, where the input fuel can be controlled, thereby controlling the resulting output, is the only solution to this low risk, high impact event.

41 The PEI transmission system was also impacted by the same storm, and even after the connection to New Brunswick was restored it took days to restore all electricity service on PEI.
42 Island summer peak load was 227 MW in 2019.

Maritime Electric intends to engage a third-party consultant in 2021 to undertake a detailed system stability study to determine the actual load-serving capabilities of an islanded system, taking into account the Summerside Sunbank and Slemon Park Microgrid projects.

In 2019, there were two hours – excluding storm outage conditions – where the Island hourly Island load was 105 MW or less[43]. These light load conditions occur in shoulder seasons at moderate temperatures, during which time the combustion turbines are derated from their maximum capabilities. The minimum nighttime load during the winter months in 2019, when the generation are not derated, was 137 MW. In addition, at least one generating unit for each of Summerside and Maritime Electric would have to reduce output in order to provide load following and frequency regulation. Table 19 illustrates the impact on load supply when PEI is islanded from the mainland with no wind generation available.

Table 19
Dispatchable Generation Availability When Islanded

Scenario	Island Load	COS Load[44]	Maritime Electric Load[45]	COS Gen For COS Load	Surplus COS Gen	Maritime Electric Load Served	COS Load Unserved	Maritime Electric Load Unserved
1	105	10.5	94.5	10.5	2.5	82.5	-	12
2	120	12	108	12	1	81	-	27
3	137[46]	13.7	123.3	13	-	80	0.7	43.3
4	150	15	135	13	-	80	2	55
5	200	20	180	13	-	80	5	100
6	250	25	225	13	-	80	10	145
7	300	30	270	13	-	80	15	190

This means that there is no single hour in the year where the on-Island dispatchable generation can serve all Island load. Firm customer load – in addition to the interruptible load already under contract – will have to be shed.

7.4.6. Carbon Impact of Additional On-Island Generation

In the short to medium term, additional on-Island generating capacity would need to be in place primarily for emergency backup purposes, either for a loss of on-Island infrastructure or for a reduction/loss of supply from the mainland.

In absence of a system situation requiring it to operate for an extended period, a new on-Island diesel generator would be projected to output roughly 500 MWh per year, mostly for training and testing purposes. This

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43 The Island load was 104 MW and 105 MW in successive early morning hours on June 26.
44 Assumes 13 MW baseload; 2 MW reserved for regulation
45 Assumes 80 MW baseload; 9 MW reserved for regulation
46 Minimum Island 2019 winter nighttime hourly loading

would consume around 115,000 litres of diesel fuel per year. Not all of this fuel usage would be incremental to the Maritime Electric's existing fuel usage; rather it would displace a portion of the fuel currently being consumed by CT3 in Charlottetown.

The projected annual consumption of 115,000 litres of diesel fuel is small compared to the overall PEI annual fossil fuel sales in 2019[47]:

- 89,189,000 litres of diesel fuel;
- 136,807,000 litres of fuel oils; and
- 237,899,000 litres of motor gasoline.

7.5. Proposed Plan

Energy Supply

Maritime Electric will continue to procure the bulk of its energy from the mainland as it is more economic than on-Island dispatchable resources, and its carbon content is considerably lower than any dispatchable on-Island resource. Renewable energy supplies such as wind and solar will provide a clean intermittent source, and Maritime Electric intends to procure future on-Island renewable supplies at cost so it can pass any potential savings along to ratepayers.

Increased Dependence on NB System

Maritime Electric will be purchasing 49 per cent of its generating capacity requirements from New Brunswick in 2020 via short term capacity contracts and its Point Lepreau participation. This will increase to 64 per cent in 2022 when the CTGS closes, and further to 66 per cent in 2024 when the current EPA with NBEM expires. This heavy dependence on off-Island systems leaves Maritime Electric open to significant cost implications should the cost or availability of surplus generating capacity in New Brunswick change.

As discussed in Section 7.2.7, Maritime Electric currently has 130 MW of transmission capacity reserved for serving Maritime Electric load. However, 30 MW of this transmission capacity is required to deliver the Company's 30 MW participation in Point Lepreau, leaving only 100 MW for delivery of purchased generating capacity. NBEM have indicated that PEI utilities will have first access to the remaining 170 MW of available transmission capacity at the NB–NS/PEI interface. However, this is not binding and is subject to change.

Generating equipment takes several years to appropriately plan, design, and install. It takes an average of three to four years to complete both combustion turbine and RICE installations[48].

On-Island Generating Capacity

Further on-Island capacity is beneficial to the Island due to the large amount of purchased capacity that the Company will require, particularly after the CTGS is retired, and the uncertainty about the long-term availability of these capacity

[47] Prince Edward Island 46th Annual Statistical Review 2019, Table 92
[48] Gas Turbine World – 2020 GTW Handbook

amounts and the associated price. It will fill the same standby and peaking role that the Company's dispatchable generation serve which is to:

- Provide some of the generating capacity that Maritime Electric needs to meet its capacity requirements under the Interconnection Agreement with NB Power;
- Provide back-up generation when there are outages or overloads on the transmission system in PEI or in New Brunswick or on the submarine cables; and
- Provide generating capacity in PEI at a time when transmission system constraints in New Brunswick limits the firm generating capacity that can be supplied from New Brunswick.

As well, additional generating capacity located on PEI will help resolve the following issues:

- Once the peak load increases beyond 355 MW, Maritime Electric will no longer be able to supply its load during a CT3 outage under no wind conditions, and will have to shed interruptible loads. Beyond 369 MW both interruptible and firm load customers will be shed; and
- With increasing loads, voltage support in eastern PEI will diminish. Generation will be required in eastern PEI when the Island load is in excess of 350 MW. A new generator installed on PEI should be designed to include a synchronous condenser that will improve power quality without consuming diesel fuel to operate.

Additional on-Island generation must be in place by 2024, and should be located in Charlottetown as a backup for CT3, to allow increased maintenance activities on the 69 kV system, and to help offset West Royalty transformer overloading.

Consideration should be given to the Borden CT1 and CT2 replacement being located near Sherbrooke substation as it is a major hub and is close to the Summerside and area load center. It could also be located in Borden, although this provides fewer system benefits.

8. TRANSMISSION

Transmission capacity is the capability of the electric transmission system to deliver energy and ancillary services to customers. A load-serving utility must have sufficient transmission capacity, or 'space in the pipeline', under contract on a transmission system to deliver energy, generating capacity and externally-procured ancillary services. Maritime Electric generally follows the North America Electric Reliability Corporation ('NERC') standard TPL-001-4 "*Transmission System Planning Performance Requirements"* when planning the Island's transmission system and sizes transmission facilities to minimize ratepayer cost over the life of the asset.

8.1. Mainland Transmission Facilities

The four submarine cables connecting PEI to New Brunswick allow Island utilities to access off-Island energy and capacity sources. This access to economic nuclear, hydro, natural gas and other renewable energy sources has been financially beneficial since Cables #1 and #2 were installed in 1977, given PEI's lack of natural resources.

Neighbouring Atlantic provinces are looking to reduce their carbon emissions in both the electricity and transportation sectors. Newfoundland & Labrador and

Quebec have abundant existing or potential hydro resources and are looking at getting these to market. Maritime Electric would benefit from access to these resources under long-term energy contracts, but reliable transmission systems are needed to deliver the energy to the Island. Quebec and New Brunswick are currently exploring additional transmission capacity between the two provinces to bring additional hydro energy into New Brunswick. Nova Scotia has expressed an interest in extending this project into that province as a way to reduce its dependency on coal.

An interruption or reduction in the capability of mainland transmission supply can leave the Island without the majority of its energy supply. It is imperative for the mainland transmission system to be reinforced so Maritime Electric can continue to access and rely on mainland sources for energy supply, and Maritime Electric will continue to take an active role in this regard. New mainland energy sources may not come with associated generating capacity, requiring Maritime Electric and other customers to provide their own capacity to backstop these energy sources. This means additional generating capacity in the Maritimes, and in particular, on the Island.

8.2. Open Access Transmission Tariff

The Open Access Transmission Tariff ("OATT"), as prepared by Maritime Electric and filed with IRAC, details non-discriminatory access to, and use of, the Island transmission system. The Maritime Electric OATT is consistent with the principles of the FERC[49] Pro-Forma OATT, as well as the New Brunswick OATT.

An OATT provides for two types of transmission service reservations, firm and non-firm, which come with different costs and priorities:

- Firm (or equivalent) – the highest level of priority of transmission service. Transmission systems are planned and built to supply firm transmission reservations. Firm transmission service is based on a long-term financial commitment by a customer to use the system; in return the system makes a long-term financial commitment to the customer in the form of transmission facilities.
- Non-firm – a lower level of priority of transmission service, and is available only when there is surplus transmission system capability. It is often less expensive than firm service, since its shorter duration allows cost optimization opportunities. The system is neither planned nor built to accommodate non-firm service, as there is no long-term financial commitment to the system on behalf of the customer.

8.2.1. Off-Island

Island load-serving utilities require off-Island transmission service reservations under NB Power's OATT to deliver energy and ancillary services from mainland facilities to the Island. Reservation levels, in turn, provide an upper limit to the amount of product that can be procured off-Island. Products such as generating capacity require firm transmission service reservations.

[49] Federal Energy Regulatory Commission

Maritime Electric's off-Island firm transmission reservations are currently capped at 300 MW, as can be seen in Table 11. Utilities in Nova Scotia and Newfoundland & Labrador currently access only non-firm energy across the interface.

8.2.2. On-Island

Maritime Electric plans the on-Island transmission system to supply the amount of long-term firm transmission reservations that exist on the system. Surplus capacity is built into the system when new facilities are added and is gradually used up as system usage grows. Both equipment thermal ratings as well as system stability have to be considered when deciding what facilities are required to deliver the firm transmission reservations.

Maritime Electric uses a form of long-term firm transmission service referred to as Network Service to serve its load. The forecast of peak load becomes the amount of firm transmission reservations that Maritime Electric needs to serve its load. Other transmission system users take a combination of short-term firm and non-firm Point-to-Point transmission service. The sum of Maritime Electric's Network Service requirement plus the long-term firm Point-to-Point service required by others is the 'Firm' load which the transmission system must be built to serve.

8.3. Identification of Needs

The transmission system is expanded to supply additional distribution substation facilities, to provide more energy transfer capabilities for both thermal and reliability purposes, to provide system cost savings over the long term, and to connect new generation facilities.

8.3.1. System Study Results

Maritime Electric undertook transmission system studies based on the load forecast included in Table 5. Many of Maritime Electric's transmission lines will have spare thermal capacity well into the future. Most of Maritime Electric's transmission system issues in the short to medium term will be driven by a lack of voltage support that will lead to depressed voltages and ultimately system instability. Lack of operating dispatchable generation will lead to a lack of dynamic voltage support, which will have negative customer supply implications. A summary of the results is below, with additional details included in Appendix B.

- On-Island generation is required to keep mainland imports below 300 MW. This can be wind generation if available, or oil-fueled when wind is not available.
- West Royalty 138/69 kV transformers overload for loss of Y-104 at system loads in excess of 295 MW when eastern PEI wind output is low. CT3 can be used to relieve the overload.
- Under voltage load shedding will be required in eastern PEI to temporarily shed load after certain single contingencies at system loads in excess of 312 MW. CT3 can be used to restore the load up to a certain level.

- Crossroads and Mount Albion Substations cannot be supported for a loss of T-2 between Charlottetown and Crossroads at loading levels above 312 MW.
- Loss of T-1 between Hunter River and West Royalty at loads above 312 MW will lead to Sherbrooke 138/69 kV transformer overloading even with all Summerside dispatchable generation operating, requiring Summerside to shed load. Summerside will be able to restore all load after Y-113 is converted to 69 kV.
- Loss of Y-111 above system loads of 330 MW results in eastern PEI voltage collapse unless generation is operating preemptively or fast-acting load shedding is initiated.
- Distribution capacitors will be required in western PEI by 330 MW Island loading to support local voltages for loss of the O'Leary 138/69 kV source.
- Reactive power support, in the form of transmission- or distribution-connected capacitors, will be required on T-1 by 335 MW loading level to support Kensington and Cavendish Farms for loss of T-1 between Cavendish Farms and Sherbrooke.
- Additional on-Island dispatchable generation required by 350 MW to keep PEI imports below 300 MW. Sherbrooke X1 transformer should be replaced around the same time, based on age (2027 timeframe).
- Significant eastern PEI generation must be operating, or a third west-to-east transmission line be in service, by 350 MW to provide voltage support. A synchronous condenser or static reactive power devices will also help, but will not alleviate the thermal overloads when either Y-109 or Y-111 trips.
- By 375 MW CT3 will not be able to sufficiently offload the West Royalty transformers for a loss of Y-104. A third source line into eastern PEI, or additional eastern dispatchable generation, is required.

The study also produced several general observations about the system:

- T-1 should be operated normally open at system peak with the open point between Kensington and Rattenbury substations. This ensures better reliability along the line, and allows higher Island load levels before overloading the Sherbrooke transformers while still keeping eastern PEI's voltage profile acceptable for a Y-111 outage.
- Simultaneous loss of NB line 1142L and Cables #1 and #2 at load levels above 304 MW can cause voltage collapse on-Island in absence of significant load shedding. In addition, unreasonably high switching voltages are encountered if either Y-101 or Y-103 is out of service and both Cables #1 and #2 are energized. For this reason both Y-101 and Y-103 must continue to be in service and maintained appropriately.
- Borden 138/69 kV transformer is one of the oldest 138/69 kV transformers on the Island and is in reasonable condition. Maritime Electric intends to operate it until CT1 and CT2 have reached end

of life, at which point a decision will be made on location of the replacement generation for Borden, as well as future voltage levels in the Borden area.

- Additional transformation or substation(s) may be needed in the Charlottetown area to divide the loads on feeders such that additional or larger lines are not required.
- Impacts from the PEI Energy Corporation's western 138 kV line have not been included in this report as the line was announced after the study work for this report was complete. A system impact study will be undertaken in the fall of 2020. As a result, the proposed western 138/69 kV substation originally proposed for the O'Leary area may be shifted from O'Leary to the Mount Pleasant area to better distribute 138/69 kV sources in the area.

Table 20 contains the short-term firm transmission capacity availability at the Sherbrooke Substation.

Table 20
Sherbrooke Substation Short-Term Firm Capacity Availability

		Available Short-Term Firm Service[50]		
Winter Heating Season	**System Peak Load (MW)**	**Existing Facilities (MW)**	**With East Royalty Substation in Service (MW)**	**With O'Leary 138/69 kV transformer plus East Royalty (MW)**
2020-21	294	14[51]		
2021-22	304	10[52]		
2022-23	312	6[53]		
2023-24	321		14[54]	
2024-25	329		11	
2025-26[55]	337			26[56]

8.3.2. System Expansion Based on Increased Reliability

Some transmission expansions are undertaken specifically to improve customer reliability and are not directly linked to system load growth. Maritime Electric has been planning for a 138/69 kV substation at O'Leary

50 Indicative figures. Allows 10 per cent overload on autotransformers at winter peaking conditions
51 T-1 open between Kensington and Cavendish Farms
52 T-1 open between Cav Farms and Sherbrooke leads to 113 per cent on West Royalty transformers, even with Clyde River in service, so that is not an option. This requires full reactive power output from Summerside's diesel generators; if they are not capable of 90 per cent power factor, the firm limit will be lower.
53 East Royalty projected to be online by December 31, 2022, which may be after winter peak.
54 East Royalty substation reduces loading on West Royalty transformers, allowing Cavendish Farms to be supplied from West Royalty and not Sherbrooke for outage to Sherbrooke transformer. Worst-case contingency now loss of T-1 between Hunter River and West Royalty.
55 O'Leary substation assumed to be in service by end of 2025.
56 Must leave open point at Rattenbury as system on verge of collapse for loss of Y-111 if move open point west of Rattenbury.

to improve western PEI reliability, support western PEI voltage, and provide a measure of backup to the Sherbrooke Substation.

Western PEI load is served by a single 69 kV line from Sherbrooke (T-5). Any substation work that impacts the T-5 portion of the bus, any T-5 breaker or switch work, or any outage along T-5 between Sherbrooke and Wellington impacts the supply to all customers west of Summerside. Western PEI is the only large region of the province that does not have some form of transmission loop in place. Central PEI has 138 kV sources at either end – Sherbrooke and West Royalty, while eastern PEI has West Royalty and Church Road at either end.

The Energy Corporation's western 138 kV line is scheduled to terminate in Tignish, which is too far west to adequately support St. Eleanor's and Wellington substations in the event of a T-5 outage between St. Eleanor's and Sherbrooke. A stepdown station in the Mount Pleasant/O'Leary area will provide a strong 138/69 kV source in the area.

8.3.3. System Cost Reduction

Maritime Electric's transmission lines have been designed to incorporate the cost of losses given the Island's historic high cost of energy. The justification for line Y-104 was in part based on the significant line loss savings that would be realized by transporting eastern PEI wind generation at 138 kV instead of 69 kV.

As described in Section 9.2.5, increasing loads in the Tignish area are leading to high distribution losses. A distribution substation located in the Tignish area will provide another opportunity for overall cost savings based on reduction of system losses, and will require cooperation with the Energy Corporation as the owner of line T-25. A second option for reducing Tignish area system losses is to construct a second distribution feeder from the Alberton station to the Tignish area.

8.3.4. Replacing Existing Facilities

The typical lifespan of transmission equipment varies depending on its components and its environmental conditions. Transmission lines (52 years), major substation equipment (40-60 years), and protection and controls equipment (10-15 years) must all be maintained and replaced at end of their useful lives.

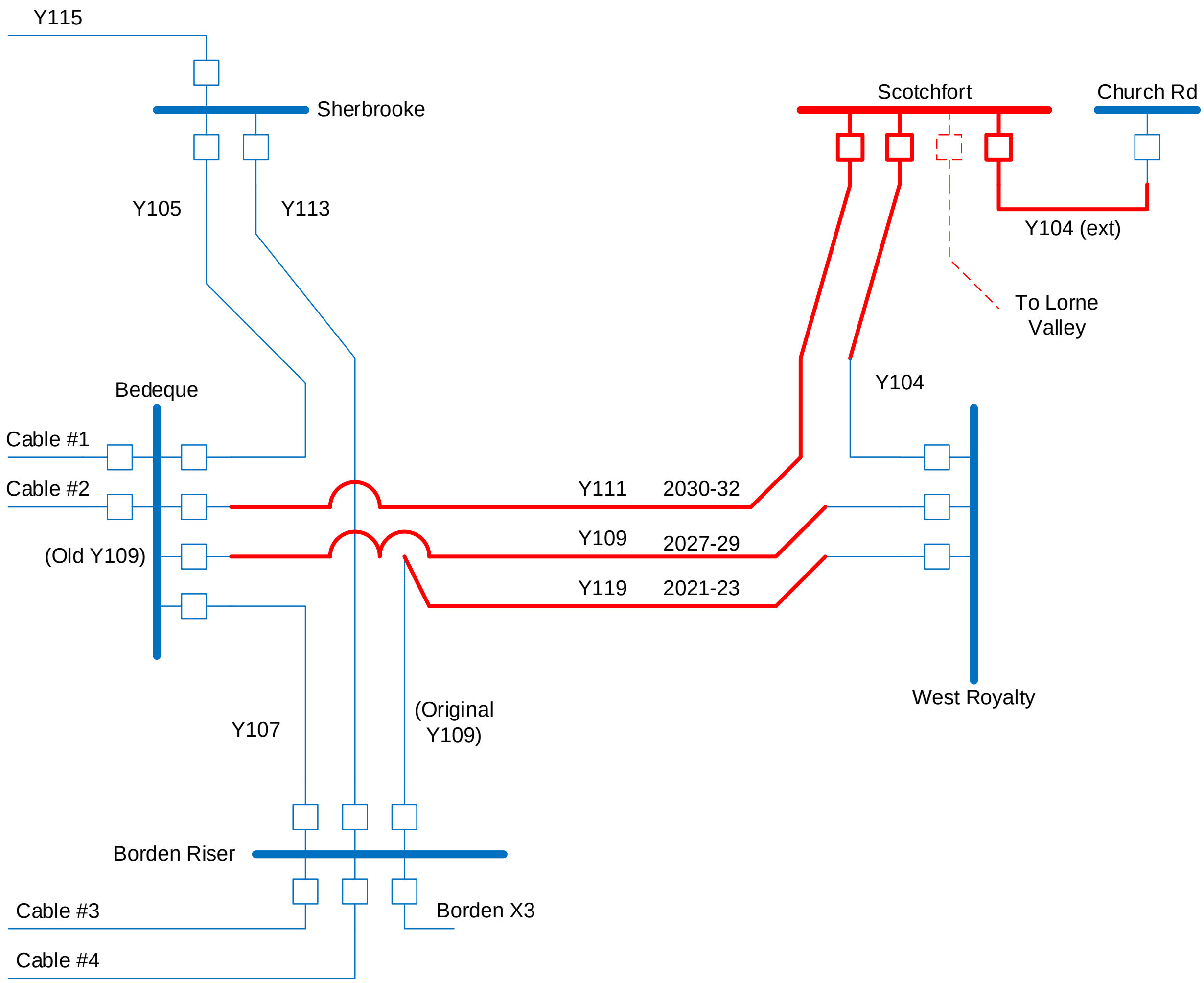
<u>138 kV Lines</u>

The system has eleven 138 kV lines. Most are in reasonable condition and require periodic inspection and spot maintenance. Lines Y-101 and Y-103 connecting Richmond Cove to Bedeque are of advanced age and require considerable maintenance. Y-115 is in good condition but is hard to maintain as portions are located in off-road areas that are difficult to access at many times of the year.

Y-109 has reached its end of life, and is being replaced by Y-119, which will be built along a different route. Y-109 will be removed from service after the three-year Y-119 construction period to ensure that eastern PEI reliability remains unaffected. The Y-109 route will be maintained after decommissioning as it will be used to locate future west-to-east 138 kV facilities. Figure 10 shows the proposed staged rebuild of the Y-109 and Y-111 facilities, as well as the completion of the third west-to-east transmission line:

- Build Y-119 from the Albany area to Warren Grove (the start of the steel towers), and when completed connect it in place of existing Y-109 (which will be deenergized). This will allow both Y-109 and Y-111 to remain in service while Y-119 is being constructed.
- Rebuild Y-109 in place when Y-111 approaches end of life. When construction is complete, place Y-109 in service and remove Y-111 from service. This will allow both Y-111 and Y-119 to remain in service while Y-109 is being rebuilt.
- Rebuild Y-111, and terminate it at Scotchfort when the third west-to-east line is required.

Figure 10 Staged Rebuilding of Y-109 and Y-111



69 kV Lines

The Island's 69 kV lines are generally in good condition as significant resources were dedicated to upgrading and maintaining the 69 kV facilities between 2000 and 2015. Lines T-1, T-4, T-10 and T-11 will need varying amounts of maintenance in the short to medium term.

Line T-1 terminates at West Royalty and Sherbrooke Substations, and connects to several 69 kV substations in central Queens County. It was constructed in 1983 in primarily off-road locations, which makes locating faults difficult, especially in inclement weather. It is beginning to show aging in certain sections, and likely needs to be replaced by the end of the decade. Maritime Electric intends to examine a roadside route when replacing T-1.

Line T-4 connects the Lorne Valley and Scotchfort substations and has reached its end of life. It was constructed in 1969, and over the past decade Maritime Electric has committed only enough resources to keep the line operational. Construction of the East Royalty substation in 2022 means that the Scotchfort substation will no longer be required in the dmedium term, and T-4 can be permanently deenergized. The T-4 right of way will be maintained as it will likely form the 138 kV line route between Scotchfort and Lorne Valley.

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

Line T-11 connects the City of Summerside's Ottawa St. substation to Maritime Electric's Sherbrooke Substation. It was originally constructed in 1963 with 2/0 AWG conductor, and a short portion was rebuilt in 1997 using larger 477 MCM conductor. The City of Summerside is the sole customer connected to T-11. Summerside does not take long-term firm service (or equivalent) under the OATT, and with its current load profile the line cannot be upgraded based on thermal loading considerations. However, the original portions of the line are aged and need to be replaced in the short to medium term. The original line must remain in service while the line is being replaced in order to maintain supply to Summerside. This presents a number of complications in an urban area, and Maritime Electric is currently working on plans to replace the aged sections of the line.

Substations

The Wellington substation was recently rebuilt after reaching end of life. The Lorne Valley substation rebuild is also complete; it was also at the end of its life, and provided neither adequate protection and control nor reliability to eastern PEI. The planned East Royalty substation will allow another end-of-life substation – Scotchfort – to be taken out of service in 2022. The Charlottetown substation is in fair condition, and needs a full structural and electrical assessment in the short term to determine its long-term viability.

138 kV substations were built primarily with steel infrastructure – as opposed to the wood structures that were typically used in 69 kV substation – and last longer. Bedeque, Sherbrooke and West Royalty Substations are all roughly 40 years old and are in good physical shape. They require periodic maintenance work but do not require a full-scale replacement based on asset condition.

The West Royalty Substation is a key system substation, comprised of both transmission and distribution system elements. Maritime Electric has developed a medium-term plan to install a 138 kV bus tie break, separate Y-109 and Y-111 on the bus, and replace two of the 138/69 kV transformers. This will improve the 138 kV bus reliability and maintainability and enable more transformation at the station. The distribution portion of the station, which includes the 69 kV, 25 kV, and 13.8 kV sections, will require upgrading in the medium- to long-term due to both age of the existing equipment as well as the electrification of both space heating and transportation. The distribution portion of the station is cramped and performing maintenance safely on the equipment is often difficult. Addition of new equipment at the station would be challenging due to the advanced age of the equipment as well as clearance around the station. EV charging will cause much higher loading on the station, meaning windows of time to maintain the equipment yet keep customers energized will be limited.

West Royalty is the only station in northwestern Charlottetown, an area that is experiencing significant residential and industrial growth. It also serves a portion of western and central Charlottetown, and acts as a 69 kV transmission hub for eastern PEI. Maritime Electric intends to undertake a detailed system study for West Royalty, its surrounding areas, and the City of Charlottetown surrounding areas in the next several years. This will help determine if the existing infrastructure can be maintained, if additional infrastructure is required, and if additional sites need to be acquired for the long-term system needs to be met.

138/69kV Transformers

138/69kV transformers were introduced to the Island when the original interconnection between New Brunswick and the Island was established. There are currently seven units in the system.

Table 21 138/69 kV Transformer Vintage				
Substation	**Transformer Number**	**Size (MVA)**	**Vintage**	**Comment**
Borden	X3	50	1976	Fair condition; will be replaced or removed when Borden CT1 and CT2 retired
Sherbrooke	X1	50	1976	Fair condition; will be replaced with 75 MVA unit in 2027-2030 timeframe
	X2	50	1991	Good condition
West Royalty	X5	50	1980	Planned replacement with 75 MVA in 2023
	X6	50	1986	Planned replacement with 75 MVA in 2026
	X7	50	2001	Good condition
Church Road	X1	75	2013	Good condition

The Canadian Electricity Association does not track transformer lifetime, and the expected life of equipment in a Canadian operating environment cannot be benchmarked. A European industry paper indicated that the mean lifetime for transformers is around 60 years[57], but this does not take into account environmental conditions. Like many other Canadian jurisdictions Maritime Electric amortizes its major transmission equipment over 50-60 years[58] and this reflects the generally-accepted useful operating lifespan of transmission equipment. Improved transformer testing and monitoring allows the Company to monitor and better predict when equipment is nearing required replacement. As a result, Maritime Electric is relying more closely on actual equipment condition than on industry benchmarks when considering replacement of 138/69 kV transformers.

Borden X3 and Sherbrooke X1 are the two oldest transformers in the system. They are in fair condition, and along with West Royalty X5 have tap changers located within the main transformer tank. These are difficult to fix, and failure of these tap changers could leak pollutants into the main transformer tank and possibly impact the transformer core and coils. A repair could take 6-12 months while a new transformer lead time is currently 18-24 months. West Royalty X5 has shown the most aging in the past few years and will be replaced first. Borden X3 has had some repairs undertaken and is expected to last until the end of the decade. Sherbrooke X1 is in better condition than the other two.

Maritime Electric currently has backup system capability for a loss of one of each of the six 50 MVA transformers. This backup is provided either through operating generation (West Royalty transformer issues) or converting Y-113 to 69 kV operation (Borden and Sherbrooke transformer issues). The amount of backup margin will diminish over time as the system load continues to grow.

57 "A Statistical Approach to Processing Power Transformer Failure Data"; Rogier Jongen et al.; 19th International Conference on Electricity Distribution; Vienna, 21-24 May 2007

58 Maritime Electric's depreciation study details the expected life of each type of transmission equipment

138 kV and 69 kV Circuit Breakers
Maritime Electric has been conducting a circuit breaker replacement program over the past several years as it recognized that the breakers, especially at 69 kV, were well past their expected service lives.

Table 22
Circuit Breaker Age Data

Equipment	Average Age (yrs)	Total in Service	Age Distribution (number)				
			0-10 yrs	11-20 yrs	21-30 yrs	31-40 yrs	40+ yrs
138kV Circuit Breaker	25	15	6	1	2	3	5
69kV Circuit Breaker	11	33	25	2	0	3	3

Maritime Electric will continue this program in the near-term to reduce the number of circuit breakers that have exceeded their expected lives.

Protection, Control and Communications
Analog protection and control equipment has largely been replaced with digital equipment that provides improved control, diagnostics and data gathering. Digital substation equipment also provides operational flexibility as quick settings changes are made as required. Communications equipment located in substations generally lasts 10-15 years before becoming outdated.

Maritime Electric has been gradually replacing its old radio network with a combination of both radio and fibre optics. Fibre networks provide a number of benefits over radio networks, including higher connection quality, higher security, and greater scalability. Fibre has a higher upfront cost than radio system, but over the long run is considered more cost effective due to its longer asset life.

Provincially-Owned Infrastructure
The Province owns the interconnection between the mainland and Island facilities as well as 69 kV transmission lines T-23 and T-25. The Province is responsible for all maintenance and replacement costs associated with the interconnection, either directly or through the Cable Contingency Fund. All costs associated with T-23 and T-25 are the Province's responsibility.

Lines Y-101 and Y-103 are the overhead connection between Cables #1 and #2 and the Bedeque Substation. These lines were built in 1977 and are showing advancing age. They will likely have to be rebuilt within the next 5-10 years. In addition, the two Bedeque 30 MVAr reactors are also owned by the Province and will require replacement by 2030.

8.3.5. Using Generation and Distribution to Resolve Transmission Issues

Reliable service to customers requires coordination between transmission, distribution and generation. Maritime Electric is slowly adding redundancy to the distribution system by connecting distribution feeders between neighbouring substations. This allows customer backup using mostly existing facilities, and sometimes removes the need to build additional transmission infrastructure for local reliability needs.

Generation serves much the same purpose, in that it can be used to backup customers when transmission is unavailable. Many of CT3's operations have resulted from lack of transmission, both on the mainland and on the Island, even though it was installed primarily as a capacity resource. Future dispatchable generation will be located, and used, in much the same way for the same purposes.

CT3 was designed with the option to add a future mechanical 'clutch' between the turbine and generator which would enable the generator to disengage from the turbine and operate as a synchronous condenser[59]. The clutch has not been installed on CT3 as the electric system does not yet require this fast-acting reactive power source. Growing system load will lead to situations where loss of a transmission line could cause voltage collapse in eastern PEI, and a synchronous condenser can be used to help stabilize the system. Future dispatchable generation located in eastern PEI should have synchronous condensing capability.

8.4. Impact of Renewable Energy Generation on Transmission Planning

Utility-scale wind energy generation additions are step increases of energy onto the system. Maritime Electric's 2005 transmission wind integration plan detailed the challenges and opportunities of incorporating up to 300 MW of wind onto the system. The Island currently has 204 MW of wind with another 30 MW scheduled to come online in 2021. Many of the results of the 2005 study are still relevant. Maritime Electric deals with proposed wind energy generation projects on a case-by-case basis since location, size, and technology all impact the connection point. The challenge from a planning perspective is to site and build the facilities necessary for connection.

The recent popularity of rooftop solar installations has resulted in over 500 total installations. This level of rooftop solar will have impacts on system power quality and may impact employee safety, and Maritime Electric is currently investigating these issues[60]. Rooftop solar does not reduce the system's peak load as the Island peak occurs after sundown during winter months.

8.5. Proposed Transmission Plan

Table 23 summarizes the projects required by the transmission system to meet the anticipated load growth.

[59] A synchronous condenser is a synchronous machine that is spinning unimpeded (not connected to a turbine or load). Its purpose is to rapidly adjust its reactive power output to draw or supply reactive power to the electric power system in response to system conditions.

[60] Source that group name that I'm on and at a high level what the group does

Table 23 Transmission System Solutions		
Projects Based on Load Growth[61]		
Project	**Year**	**Comment**
East Royalty Substation	2022	Locates a substation closer to load growth and allows end of life Scotchfort and line T-4 to be retired. Scotchfort transformer will be redeployed.
Generator – Charlottetown area 69 kV	2024	Provide backup and emergency services; allows maintenance on Charlottetown area equipment; will be required to support area as load grows; backup for CT3; provide voltage support if synchronous condenser option included; leverage during negotiations. Latest this can be in service is 2027 in order to maintain NB-NS/PEI interface at allowable levels for loss of CT3.
T-1 reactive power support	2025	Provide voltage support in the middle of the line for loss of section of line at either end
Western PEI Distribution Capacitors	2027	Required to ensure sufficient voltage support in western PEI for loss of O'Leary stepdown substation
Scotchfort Substation Rebuild	2027+	Replace Scotchfort substation removed from service in 2023; support load growth in Scotchfort area and provide backup capability to both East Royalty and West St. Peters
Third West-to-East 138kV line	2027+	Ensures generation doesn't need to be preemptively operated at load levels above 353 MW to guard against Y-109 or Y-111 outage; allows maintenance to be undertaken at West Royalty and Charlottetown substations
138kV Source at Lorne Valley	2027+	Offload West Royalty transformers; minimize operation of eastern combustion turbines; provides much stronger system to eastern PEI, allowing more robust maintenance activities; supports Crossroads and Mount Albion for T-2 outage
Projects Based on Equipment Condition		
Project	**Year**	**Comment**
Y-109 Rebuild	2021-2023	Replace Y-109 with Y-119, as Y-109 has reached end of life
West Royalty X5 Replacement	2023	Replacement of oldest West Royalty 138/69 kV transformer with a larger unit
T-11 Rebuild	2024	Portions of the line are reaching end of life and have to be replaced
West Royalty X6 Replacement	2026	Replacement of second West Royalty 138/69 kV transformer with a larger unit
Y-111 Rebuild	2027+	Line will be approaching 40 years of age; subjected to same weathering conditions as line Y-109
Projects to Enhance Customer Reliability		
Project	**Year**	**Comment**
O'Leary/Mount Pleasant 138/69 kV substation	2024	Provides voltage support to western PEI; allows maintenance on Sherbrooke substation, and lines T-5 and T-21 without needing customer outages; quicker customer restoration after issues on T5 and T-21; offloads Sherbrooke transformers; enables second path for both West Cape and North Cape wind output

In absence of eastern PEI generation (wind or CT3), line Y-109 overloads for loss of Y-111 at system peak loading levels higher than 295 MW. Similarly, Y-111

61 Based on load forecast included in Table 5

overloads for a loss of Y-109 at the same load levels. This can be resolved by load shedding, generation dispatch, or addition of a third 138 kV transmission line between the Bedeque/Borden area and eastern PEI. In the event that dispatchable generation is not added in the Charlottetown area, the third west to east line will be required by 353 MW to ensure Y-109 loading can be brought below 100 per cent for a loss of Y-111, even after CT3 is dispatched.

9. DISTRIBUTION

Distribution system planning is heavily dependent on local conditions and is influenced by subdivision construction, industrial and commercial expansion, and pockets of technological advancement and implementation. The size, length and quantity of distribution feeders, as well as distribution-connected voltage support devices, are guided by CSA standard CAN3-C235-83 which specifies acceptable system voltages at the point of customer connection. There are currently 69 distribution feeders sourced from 22 stepdown substations. Each substation's 2019 annual peak is shown in Appendix C.

Table 24
Distribution System Asset Summary[62]

Number of Customers	79,497
Overhead Lines	5,329 km
Three Phase	1,294 km
Single Phase	4,035 km
Underground Lines	43 km
Three Phase	11 km
Single Phase	32 km
Total Distribution Lines	5,372 km
Substation Transformers	32
Distribution Transformers	37,956
Padmounts	1,154
Pole Mounts	36,802
Reclosers	100
Capacitor Banks	144
Voltage Regulators	142
Metering Tanks	86

9.1. Identification of Needs Based on Reliability

9.1.1. Historical Replacement Rates

Table 25 shows the number of distribution pole mount transformers installed or replaced over the last five years. With approximately 36,800

[62] As of July 1, 2020.

transformers in service and an expected life of 40 years, an average installation rate of 920 transformers/year is required in order to achieve a sustainable average transformer age and condition. Spill prevention installations require an additional 200 distribution pole mount transformers annually[63]. Approximately 520 pole mount transformers are installed annually to facilitate new customer connections and overloaded transformers. The target rate of installations is 1,640 distribution pole mount transformers per year. The average installation rate for the past five years has been 1,505 transformers per year, which is roughly 8 per cent lower than the annual target.

Table 25
Historical Distribution Transformer Replacements

Year	# Transformers Installed	Surplus/Deficit
2015	1,240	-400
2016	1,569	-71
2017	1,557	-83
2018	1,577	-63
2019	1,580	-60

A program to optimize distribution transformer installations will reduce the number of transformers installed. The program will consist of installing a larger sized pole mount transformer in locations where successive groups of poles have distribution transformers mounted upon them. The large pole mount will serve all customers in the area and the other transformers will be removed. This program will optimize the number of distribution transformers managed and the system capacity of distribution transformers in the field.

With 144,900 poles in service and an expected technical life of 50 years, an average replacement rate of 2,900 poles/year is required in order to achieve a sustainable average pole age. Since some poles are installed in 'fresh ground' to facilitate new customer connections rather than replacement of an aging pole, the number of removed poles may be somewhat less than the totals shown in Table 26. The average 'replacement deficit' prior to 2015 had been about 1,300 poles.

Table 26
Annual Wood Installations and Replacements

Year	# Poles Replaced/Installed	Surplus/Deficit
2015	1,331	-1,569
2016	2,997	+97
2017	3,121	+221
2018	3,554	+654
2019	4,058	+1,158

[63] Spill prevention program concluded in 2019.

9.1.2. Distance between Substations

The Island's distribution substations are generally located in the centre of the Island, close to main highways and transmission facilities, with distribution feeders projecting outwards to the periphery. Increasing reliance on electricity for space heating has driven the need for several additional substations to supply the load. Electrified transportation will put further strain on the existing system, especially in the rural areas where substations are further apart.

Maritime Electric's goal is to locate rural distribution substations approximately 20 km apart. This distance will ensure: a) adequate supply to both existing and growing load; and b) substations will be able to back up feeders from neighbouring substations in most cases. It will ensure continuity of service during substation maintenance work as well as quicker service restoration during outages on main substations feeders.

9.1.3. Size and Length of Distribution Feeders

Size and length of distribution feeders has a significant impact on customer reliability. A feeder with a large number of customers will impact many customers when there is an outage. Similarly, there are many lost customer hours of service when there are issues on long feeders since the issues are often more difficult to find given the feeder's length. Maritime Electric had 1,418 customers per feeder in 2017, which was higher than the Canadian average of roughly 980 per feeder. The addition of Bagnall Road and Mount Albion, plus the rebuild of Wellington, have reduced Maritime Electric's customers per feeder to 1,152 in 2020. Clyde River and East Royalty will further reduce this number, although there is only one net new feeder with East Royalty's addition since it is replacing the existing Scotchfort Substation.

Maritime Electric's 2017 average distribution feeder length was 93 km, compared to a Canadian average of 55 km. The additional feeders installed in the past three years have reduced Maritime Electric's figure to 78 km per feeder, which is still above the 2017 Canadian average, but will lead to improved customer reliability.

Simply adding a feeder to reduce the number of customers per feeder won't necessarily have a demonstrable impact on reliability. Each location has to be examined to ensure that additional feeders within a substation – or added as part of a new substation – will separate customers onto different feeders and consequently reduce the impact of a single outage. New substations will be designed with the capability to supply at least four distribution feeders.

9.1.4. Distribution Redundancy and Automation

Redundancy on the distribution system directly leads to increased reliability. Maritime Electric is gradually extending key three phase feeders to connect to neighbouring substations' feeders. This both serves new customers along the route as well as allows backup from the neighbouring facility.

Distribution systems are becoming increasingly automated in a bid to improve reliability as well as reduce maintenance costs. Automated equipment is gradually being placed on the distribution system to allow Maritime Electric to quickly shift load from one feeder to another when required. There are a variety of products and technologies available that may prove valuable to Maritime Electric's customers. Maritime Electric intends to add distribution reclosers at locations along Maritime Electric's fibre network as a starting point which will be controlled by ECC Operators. Maritime Electric is also trialling fault indicating equipment along distribution lines. While this technology has been available for years, the impacts of its application on Maritime Electric's system is unknown and will be evaluated in the coming years.

9.2. Identification of Needs Based on Load Growth

The distribution system is continuously expanding to meet an increasing number of customers.

9.2.1. New Facilities and Services

The distribution system has much more maintenance and new construction activity than either transmission or generation based on the amount of equipment and new connections to the system. Table 27 shows the annual new meter and service installations over the past five years.

Table 27
Maritime Electric Annual Customer New Meter Installations and Services

Year	New Meter Installations	New Services[64]
2015	1,073	779
2016	1,240	973
2017	1,365	1,091
2018	1,658	1,101
2019	1,601	1,009

9.2.2. Cavendish Area

Cavendish continues to be one of the busiest tourist areas on the Island in the summer. It encompasses approximately 850 customers during the peak summer season, including campgrounds, an amusement park and the Cavendish Beach Music Festival, with a summer peak of 3.8 MW. There are unique challenges in serving the area due to the large load influx for only three months every year. The Resort Municipality, which consists of Stanley Bridge, Hope River, Bayview, Cavendish and North Rustico, has voiced concerns about power quality and reliability in the area during the past years.

Several options have been examined, including new distribution feeders from Rattenbury and Bagnall Road and a new 69/12.5 kV substation in the Cavendish area. Rattenbury historically supplied backup to the area, and is projected to need a new transformer in 2021. The Bagnall Road

64 New services such as streetlights and crosswalks do not get meters, yet require capital expenditures.

substation was built in 2018 to offload the Hunter River substation, and also provides support to the Cavendish area. However, the concentration of load in Cavendish is a long way from either substation, making it hard to provide backup in the high tourist season.

A Cavendish area substation would mostly address the issues, although siting a new substation may encounter difficulties from environmental and residential consultations. It would provide the best reliability but would also be the most costly. Maritime Electric will continue to study its options for supplying the Cavendish area.

9.2.3. Crapaud Area

The new Clyde River Substation will split the 6,600 customers on the existing Bonshaw feeder over five feeders, which will have a significant impact on customer reliability on the Bonshaw feeder. It will still be able to backup the existing Bonshaw 25 kV feeder at most times of the year.

The southern Queens County area 12.5 kV customers will continue to be supplied from Albany Substation. There is insufficient load and customers to currently justify another substation in the area, however increasing load in Crapaud and Victoria-by-the-Sea may change this in the longer term.

9.2.4. Mount Pleasant Area

The O'Leary and Wellington Substations will be unable to adequately supply load east of Mount Pleasant in the long term due to thermal and customer voltage issues. In addition, there is limited load backup potential given the 37 km distance between O'Leary and Wellington. It is impractical to build additional distribution feeders between the two stations in order to provide more capacity and additional reliability, since:

- The most direct and least expensive route (following Route 2) already has the T-21 transmission line on one side and a three phase distribution line on the other side. It would require one line to be removed and rebuilt as a double-circuit pole. A single tree leaning over due to weather events or a motor-vehicle accident could interrupt both circuits. There is little reliability to be gained by following Route 2.
- Most of the O'Leary load is located west of the O'Leary Substation, and is over 40 km from Wellington. It is impossible to effectively supply this load from Wellington on an emergency basis.
- Lennox Island load, which is 25 km from Wellington, is growing. Routing a new distribution feeder would be expensive since an existing feeder would have to be replaced. In addition, distribution losses are very high when transporting energy this distance.

A distribution substation between O'Leary and Wellington in the Mount Pleasant area would alleviate these issues by providing voltage support to the area and back up to both O'Leary and Wellington. It would also meet the long-term target of 20 km between each distribution substation. In addition, it would be located at or close to a Mount Pleasant 138/69 kV substation if that becomes the preferred location for the western 138 kV source.

9.2.5. Tignish Area

A lengthy distribution feeder currently serves the Tignish area from the Alberton substation, with no opportunity for backup supply. While Alberton substation transformers have sufficient spare capacity, loading on the feeder is leading to high distribution losses given the length of the feeder.

Table 28
Tignish Feeder Peak Load Growth

Year	Peak Load (MVA)
2016	7.343
2017	7.807
2018	7.797
2019	7.628
2020	7.944[65]

A Tignish substation would reduce distribution system losses by 370 kW during peak loading periods, which equates to roughly $75,000 in levelized annual loss savings over the life of the feeder. A second distribution feeder between Alberton and Tignish will be considered as well, as it would likely cost considerably less but have lower loss savings. Maritime Electric will continue to monitor the Tignish area loading and reliability, and will undertake studies as necessary to determine the most economical solution.

9.2.6. Bedeque/Kinkora Area

The area directly to the south of the City of Summerside is supplied from the Albany Substation. This extended distance is prone to outages, and load growth south of Summerside is straining supply from the Albany substation. Kensington Substation is closer, but is not capable of picking up the extra load at peak times.

The Bedeque switching station currently has only 138 kV equipment. A 138/12.5 kV source at the Bedeque station could offload the Albany substation, provide backup to Albany and Kensington customers, and provide more reliable service to customers south of the City. Maritime Electric will continue to study the area and determine the supports most appropriate for the customers.

9.2.7. Scotchfort Area

The Scotchfort Substation is scheduled to be removed from service when the East Royalty substation is completed in 2022. A distribution source at this location will not be needed in the short to medium term as the area can be sufficiently supplied by East Royalty and West St. Peters. However, electrified transportation will likely lead to voltage and backup issues for the Scotchfort area given its distance from East Royalty and West St. Peters.

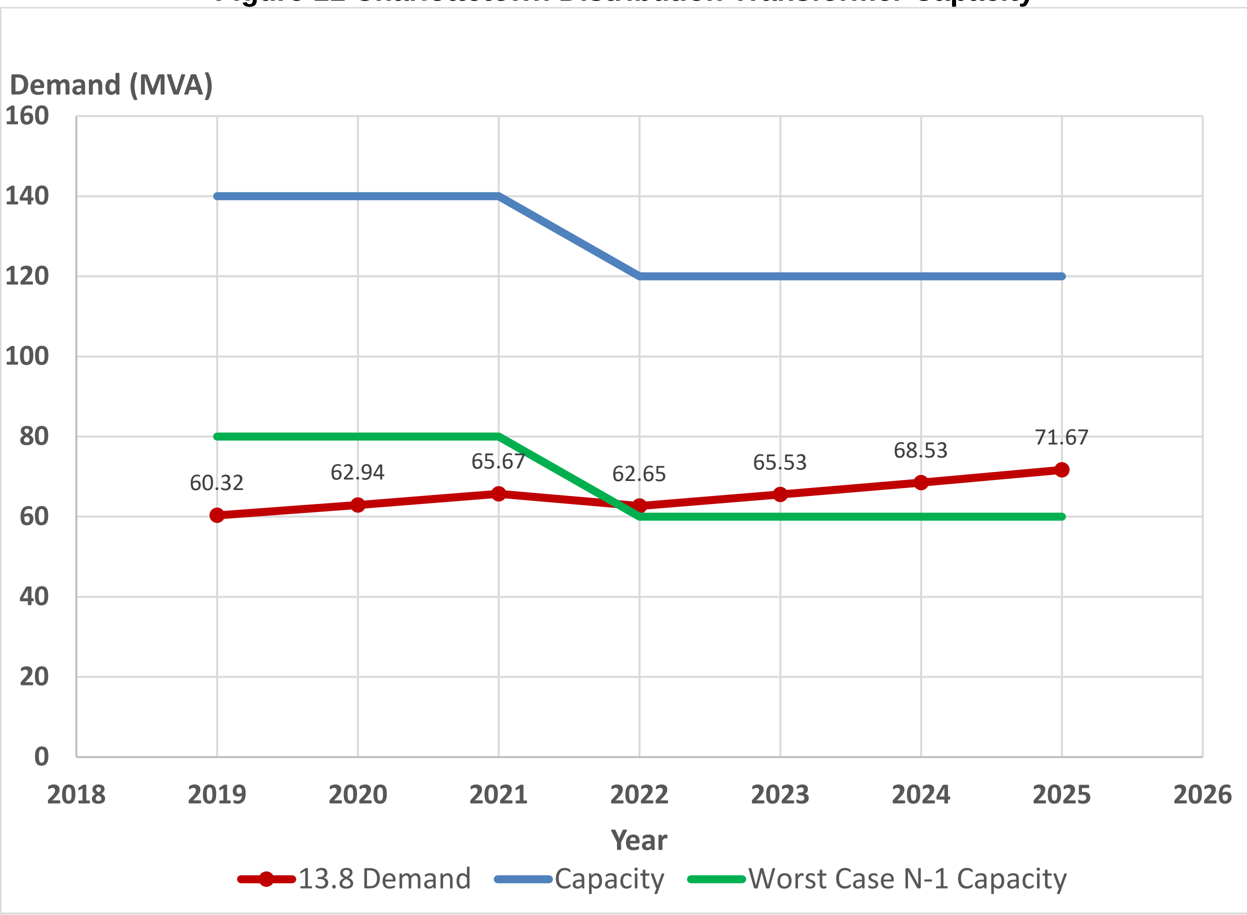
65 First six months of 2020

The Company expects that a new distribution substation will be needed in the Scotchfort area in the long term. It will align with the Company's goal of approximately 20 km between distribution stations, enabling sufficient reliability for customers in East Royalty, Scotchfort and West St. Peters substations as their energy needs become increasingly served by electricity.

9.2.8. CTGS Closure Impacts on Distribution Facilities

The CTGS is scheduled to be decommissioned in 2022, and the sole remaining CTGS 69/13.8 kV transformer (Charlottetown X2) will be removed as part of this decommissioning. The Charlottetown area will have insufficient stepdown transformer capacity to supply the load for the loss of the largest single unit (Charlottetown X4) once Charlottetown X2 is removed from service. Figure 11 shows the shortage of transformer capacity in Charlottetown after the CTGS is decommissioned.

Figure 11 Charlottetown Distribution Transformer Capacity



Maritime Electric can either: a) add transformation capacity, or b) operate CT3 as an island with some Charlottetown load in order to address the transformer shortfall. CT3 islanded with City load is the short term solution to this issue as there will be few hours per year that this situation exists so the potential costs impacts are small. CT3 islanded operation will become more prevalent as Charlottetown load increases with rising urban density, space heating and electrified transportation needs, and additional distribution capacity in the Charlottetown area will become economically attractive. Maritime Electric continues to look at the need, possible locations, and timing of additional distribution resources in the Charlottetown area.

9.2.9. Cold Load Pickup

Maritime Electric has occasionally experienced cold load pickup challenges on long and heavily loaded feeders. In the case of transmission system restorations, distribution feeders are currently disconnected prior to transmission line re-energizations to minimize the impact of cold load pickup.

Maritime Electric is working towards reducing the number of customers and the total length of distribution lines on each feeder by adding more substations and more distribution feeders. Maritime Electric is also working on deploying more ECC controlled reclosers on the feeders (along with the installation of fibre networks). The measures will help address the some of the cold load pickup issues.

9.3. Technology Impact on Distribution System

Customer-Level Energy Storage

Several customer-level energy storage options are available but to Maritime Electric's knowledge there has been little uptake on the Island. These devices will causes issues for system, public and Maritime Electric employee safety if they are not properly installed. Although it is not law, Maritime Electric needs to know where these are on the system in order to operate the system safely, as the Company will have to change its operating procedures in order to accommodate working on its system with these devices installed. This will have a negative impact on the reliability of customers without these energy storage devices, as extra time and precautions will have to be taken to ensure the energy storage device are not backfeeding into a deenergized system.

EV Impacts

Public charging infrastructure will be installed with Maritime Electric's knowledge, so Maritime Electric can ensure that the local distribution system is prepared for the impacts from the charger. Private EV charging – either home- or business-based – is different as there currently is no obligation for those customers to inform Maritime Electric of the charger on their system. EVs will have an immediate impact on distribution facilities at the neighbourhood level.

A Level 2 EV charger electric load is roughly equivalent to two regular-sized clothes dryers. Commercial electrical infrastructure often has sufficient spare capability to accommodate this increased load, but local residential distribution infrastructure may not. Most of Maritime Electric's residential infrastructure was constructed before electrified space heating became popular. Newer distribution facilities have taken electrified space heating into account, but the impacts of transportation will be significant.

Maritime Electric needs to expand the capabilities of its system in a measured approach – increasing the system's capabilities when needed but not unnecessarily – but has no visibility of electrified transportation. Industry groups are studying how to best approach electrified transportation to ensure that the proper procedures are in place, but minimizing the amount of overbuild that goes into the system. Smart meters with advanced software may be able to detect where an EV has been connected and may be able to provide Maritime Electric with key data, but this will still be after the EV is on the system, which may encounter issues before Maritime Electric has the chance to review and upgrade the local system. Maritime Electric needs a way to see where EVs have been, and will be, located so that it can review and potentially upgrade its system accordingly.

Smart Meters

Smart meters have been available for the past 15-20 years. Many technological advances have been made since the first edition of these meters was developed. Current meters have many capabilities, including two-way communication, interval readings (useful for billing and load research purposes), remote connect/disconnect functions, remote reading, and remote customer voltage and connectivity signals.

Smart meters will enable time of use rates to be adopted, which combined with appropriate rate price signals will help reduce system peak loading by enticing customers to shift load to off-peak periods.

In addition, some versions of the newer meters have data analytics functions built into the unit, which allows the meter to discern each load that is connected behind the meter. The meter can differentiate, for example, between a kettle, an oven, lights, and computer load. The meter may be able to accurately track the time and amount of energy and demand delivered to a residential EV charger, which may be able to assist governments when they are looking to replace lost gasoline tax revenue as EVs gain popularity.

Maritime Electric's billing and customer databases are not capable of accommodating a smart metering system, and will require replacement if the Company pursues smart meters.

9.4. Proposed Plan

Maritime Electric will continue to connect new customers to the system and will incorporate changing customer load patterns into its forecasts. It has exposure to unknown additional EV charging load, which can impact both that customer as well as neighbouring customers. Maritime Electric will consult with industry and develop design standards that address this transformational load.

Once the East Royalty substation is complete there is no immediate need for another distribution substation based on current load projections. Tignish, Mount Pleasant, Cavendish and Bedeque will be closely examined to determine the timing of their needs. Distribution work will concentrate on strengthening and expanding the capabilities of the existing system to both increase reliability and prepare for electrified transportation by:

- Constructing distribution line extensions to provide connections to neighbouring substations to help with maintenance and storm restoration options;
- Upgrading aged or inadequate substation transformation equipment with newer and/or larger equipment;
- Adding distribution automation in select areas to determine its effectiveness and applicability to the Maritime Electric system; and
- Modernizing substations to ensure they meet electrical code standards, can accommodate a mobile transformer as needed, and have communications and P&C equipment that meets cybersecurity needs.

Longer term system developments involve additional substations to meet the expected EV transportation load. It will be increasingly important to have distribution substations adequately spaced to supply the load from thermal, voltage, and backup perspectives. One or two large step loads can quickly make a difference on a rural electrical system.

10. CHARLOTTETOWN PLANT SITE PLAN

The Charlottetown Plant site has been used by Maritime Electric and its predecessors for over 150 years. When Maritime Electric was formed it assumed the remaining portion of a 999-year lease which was entered into in 1853 for 1.2 acres of land at the corner of Sydney and Cumberland Streets that now forms part of the Charlottetown Plant site. This leaves 832 years left on a land lease that costs ratepayers very little. Maritime Electric owns the rest of the Charlottetown Plant property. The oldest existing facilities onsite date back to the 1920s. Most of the CTGS building sits on the leased property, and decommissioning of the CTGS equipment in 2022 presents the opportunity to look at the site's long term usage.

Maritime Electric believes that preserving the existing CTGS building is a long-term safety and cost liability, and has proposed to IRAC that the building be removed and the ground levelled[66]. While it is possible to keep at least a portion of the building intact to house future generation, it is not recommended:

- The cost of installing the generation would be higher than a freestanding structure, due to the need to hoist most of the equipment and put in onsite through the roof;
- Construction of the foundation would be difficult due to the confined nature inside the building. The existing building foundations would not support a combustion turbine and would need to be removed before the new foundations can be built;
- Combustion turbine packages come standard with safety, noise abatement, and fire retarding systems built into the enclosure, whether located outdoors or indoors. If this standard enclosure is not included, custom designs are required and the cost can be significant. For example, the combustion turbine cooling ventilation system requires the air surrounding the package to be replaced several times per minute. If the volume of space surrounding the turbine is increased, the cost of the cooling ventilation system goes up. Locating a combustion turbine within the CTGS will be more expensive than a standard outdoor setting, and would be solely for aesthetic reasons; and

[66] IRAC Docket UE23001.

- Maritime Electric will consider purchasing a used combustion turbine in the future. Experience has shown that Maritime Electric combustion turbines are operated infrequently, and Maritime Electric neither expects nor needs a turbine to be capable of operating for thousands of hours per year for the next 40 years. A lightly-used turbine will provide the same reliability to customers, based on its projected usage, for likely much less upfront capital cost. The requirement to house a future generator in the CTGS building may limit Maritime Electric's flexibility in procuring a lightly-used generator for its future needs.

Following IRAC's order to further investigate the possible use of the CTGS building, Maritime Electric hired a consultant to investigate repurposing the building to house office space. The consultant determined that the cost of upgrades required to bring the building up to code and to house offices was prohibitive[67].

Maritime Electric still believes that removal of the CTGS is the best long-term cost option for the Company and the ratepayer, and removes a significant safety risk for the Company. There are several options available to the Company for the Charlottetown Plant site with the CTGS building removed:

1. Remove all equipment from the Charlottetown Plant site and sell the site to others;
2. Continue to operate the existing equipment, and sell the surplus land owned by the Company to a third party (exclusive of the leased land component);
3. Continue to operate the existing equipment, and keep the surplus land for future Maritime Electric use;
4. Continue to operate the existing equipment, and add dispatchable generation; or
5. Continue to operate the existing equipment, and relocate Maritime Electric's head office to a new building constructed on the CTGS site.

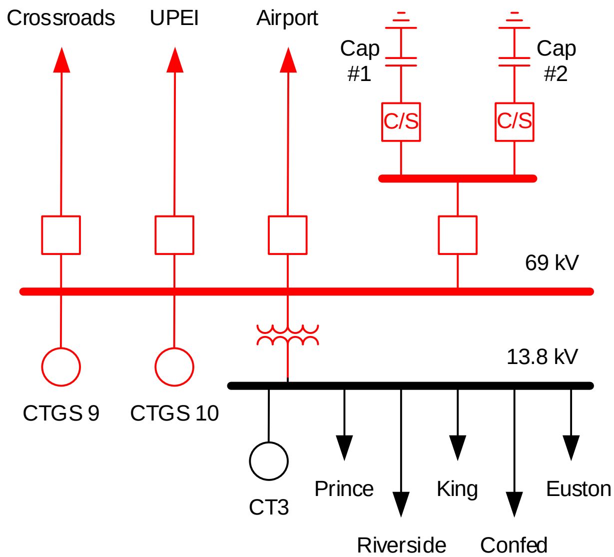
Electrical Importance of the Plant Site

The site currently contains the CTGS building and equipment, CT3, Energy Control Centre building, and the Charlottetown substation. Energy produced by CT3 is supplied directly to the substation's 13.8 kV distribution bus, allowing it to supply the five connected feeders even if either the entire substation or step up transformer is out of service. CT3 is typically connected to the transmission system, and its surplus energy is exported from the substation to other customers via the connected transmission lines.

It is a key transmission location for the Company, having two connection to West Royalty (with taps to UPEI and the Airport substation), as well as supplying eastern PEI via line T-2 which connects to Crossroads, Mount Albion and Lorne Valley.

[67] Appendix B to CTGS Decommissioning Semi-Annual Report, June 2020.

Figure 12 Charlottetown Substation



Many key public services, including the Charlottetown Wastewater Treatment Plant and the Queen Elizabeth Hospital, are in close proximity to the Charlottetown substation and benefit from the high reliability of this substation. Continued substation facilities at Charlottetown is beneficial in providing reliable service to these key loads in addition to downtown Charlottetown.

The site's close proximity to the Irving fuel terminal and pipelines make fuel supply and delivery more secure, particularly during severe transportation issues on the Island. While this close proximity is convenient and meets Maritime Electric's present day fuel usage needs, the Plant site could be connected to the existing pipeline in the future should the Company's mode of operation change. The combination of substation importance, existence of generating assets on-site, ready access to fuel supplies and/or delivery channels, and proximity to key loads means the Charlottetown Plant site is key to the Company's future energy supply needs.

The Plant site is an existing industrial site, and adding generation and substation equipment to the site would be a continuation of past use. The Plant site and Charlottetown substation can help the Company meet its need for additional on-Island capacity as they are capable of accommodating a second combustion turbine in the 50 – 75 MW size range. A larger unit would likely exceed the current capabilities of the substation, and may concentrate too much future capacity in one location. It is not anticipated that a third combustion turbine would be added at the site unless additional substation and transmission capacity were added.

Other locations in the Charlottetown area have been considered as a greenfield site for another combustion turbine. No site has the same combination of transmission, distribution, fuel delivery and fuel handling ease as the Charlottetown Plant site. All other sites would be much more expensive to acquire, develop and construct.

The Charlottetown substation will require replacement within the next decade as it is approaching 60 years of age. A standard outdoor substation is the mostly likely option, built adjacent to the existing substation. Indoor gas-insulated switchgear is a more compact design and is sometimes chosen for urban environments, but it is far more costly to install and limits future expansion and flexibility of the equipment.

Climatic Impact on the Plant Site

CT3's design in 2004 was influenced by the potential flooding risks over its expected 50 year lifespan. Its foundation was built up to 4.82 m CD[68], which exceeded the 50% flood probability within 50 years prediction at the time. More recent environmental studies have shown that the Charlottetown Plant site is susceptible to even higher coastal flooding up to the year 2100 during extreme total sea level rise conditions. The City of Charlottetown has set 5.45 m CD as the minimum elevation for waterfront properties.

While these flooding conditions are rare – the only recent extreme event with major water ingression at the Plant site was during 'White Juan' in January 2000 – the Company must ensure any facilities constructed there are able to both withstand, and be operable during, an event. This includes employee access to the Charlottetown Plant site and its equipment. Climate change adaptations will have to be developed and implemented in order to continue to use this site.

Maritime Electric has undertaken a high-level examination of the site and has determined that it will be able to add to or replace infrastructure at the site that can effectively accommodate the required climate change adaptations. The two main options available to the Company are raising the ground level or surrounding the site with a dike-like structure.

Raising the ground level for new infrastructure is the most cost-effective option and would require the least work at the site. New infrastructure would be built to ensure its base level is above the projected flood level, and the ground surrounding it would have to be sloped to allow operational and maintenance access to the equipment. This may not require much site grading. Access to the site will have to be examined to ensure that, even though the equipment is operating and above the coastal flooding levels, the site is still accessible by Company personnel.

A dike built around the entire Charlottetown Plant site would protect existing and future infrastructure. While this would ensure the site will remain water-free during the extreme coastal events, it would mean that any water that enters the site (via rain or melting snow) would be trapped onsite and unable to naturally flow off the site. A system to drain any trapped water would be required. A pumping system, using the existing cooling water pipes from the CTGS to the Charlottetown harbour, could be devised if it meets environmental standards. A dike would also require road access to the Plant site to be realigned since Richmond Street is not at the required elevation. The Richmond Street access to the Plant site may have to be closed, and access to the site limited to Water Street. Maritime Electric feels that

[68] CD refers to Chart Datum, which is a typical water level measurement unit that displays depths on a nautical chart. It is generally derived from tidal phases.

targeted ground elevation increases is more cost effective in both the short and long terms.

Discussion and Analysis of Options

Remove all equipment from the Charlottetown Plant site and sell the site to others

In 2015, Maritime Electric undertook a high-level costing analysis of relocating CT3 from the Plant site to a generic greenfield site on the outskirts of Charlottetown. The cost was determined to be $25.8 million (2015$), and details were included IRAC *UE20723 (CT4) Responses to Interrogatories – PEI Energy Corporation, IR-10*. The Company undertook further studies to determine the cost to both reduce its footprint on the Charlottetown Plant site or withdraw from the Charlottetown Plant site entirely. The cost of either option was roughly $50 million (2015$), which included the $25.8 million to move CT3. A breakdown of these costs is included as Appendix D[69]. Maritime Electric believes that the cost of remediating the site prior to sale would be at least as much as the proceeds from a sale.

Moving the Charlottetown Plant site infrastructure to another location would not improve customer reliability, nor would it save the Company money in the cost of providing service. The costs associated with this option – an estimated minimum of $50 million – are not justifiable to Maritime Electric's customers, and would have to be fully covered by a third party wishing to take over the Charlottetown Plant site. Maritime Electric does not believe this is a viable alternative, and as such Maritime Electric is neither using resources to update the 2015 cost figures nor contemplating vacating the Charlottetown Plant site.

Operate existing equipment and sell surplus land to third parties

The CTGS building is in the southwest corner of the Charlottetown Plant site property, and sits adjacent to Maritime Electric's ECC, CT3, Charlottetown substation and control building. Most of the CTGS building is located on land leased from the Cumberland Trust, and has favourable economic terms for the Company and ratepayers. There will be limited appetite for third-party use of the site based on its industrial history, and depending on future use Maritime Electric will likely undertake an environmental remediation on the site before selling the land to others. The costs associated with environmental remediation will likely be higher than the proceeds from sale of the land owned by the Company, as site testing has shown soil contaminants are present from its years of producing electricity from coal and heavy oil. Maritime Electric believe that sale of this property and transfer of land leases to others is not economically viable, and is not in the interest of ratepayers.

Operate existing equipment and keep the surplus land for future Maritime Electric use

The utility industry is entering into a period of great change and uncertainty. Electrified transportation and space heating will drive the Island's energy and peak

[69] This cost estimate includes the 2015 estimated cost to remove the CTGS building, but did not include any costs associated with environmental remediation necessary to sell the site to a third party, nor the proceeds from such a sale.

demands in the next decades. Renewable energy will continue to increase its supply penetration.

Energy storage will also be a key factor, and has the potential to transform the industry in the long term. Current storage technologies will likely remain uneconomic as their cost and technology gains are incremental. A transformative change in storage technology could lead to wide-scale adoption, enabling large scale storage of renewable energy.

Small modular nuclear reactors are also currently of interest. What this technology looks like is unknown, but access to a heat sink may be a necessary part of the process if past practice is a guide (i.e. nuclear generation). The Charlottetown Harbour is a natural heat sink and has been used in that capacity for the past 100 years by the CTGS. Ready access to this cooling source is a valuable attribute of the Charlottetown Plant site.

Operate existing equipment and add dispatchable generation

The Charlottetown Plant site has existing fuel storage and offloading, existing dispatchable generation (CT3), a 69 kV substation that connects both to West Royalty substation as well as eastern PEI, and proximity to critical loads in Charlottetown.

Maritime Electric is in need of additional on-Island dispatchable generation, sized around 50-75 MW. The existing Charlottetown Plant site and substation have the space to accommodate generation and its transmission connections, even with the CTGS building left in place, although the site would have a less efficient layout if this was completed. The CTGS building, while technically capable of containing a new generator, cannot do so practically or economically. A new generator would be best placed in the location of the CTGS close to, or just south of, the existing machine shop. This would leave a reasonable buffer between the generation and local residents, and would allow additional site infrastructure when required.

Operate existing equipment and relocate Maritime Electric's head office to CTGS site

Maritime Electric's office building at 180 Kent Street is aged and requires upgrades to bring it up to today's standards. Maritime Electric is contemplating looking into selling its office building at 180 Kent Street and relocating those offices to the Charlottetown Plant site. A new energy efficiency building would be constructed at an elevation above flooding projections and would house Maritime Electric's ECC as well, ensuring that critical function remains above storm surge levels.

This is not the preferred use of the site, but would allow Maritime Electric to consolidate its properties and operate an energy efficient office building. This building could also provide a physical buffer between CT3 and the Cumberland Street residents.

Plant Site Plan

The Charlottetown Plant site has fuel storage and offloading, existing generation, proximity to load and transmission, and an existing substation. It is the ideal site for the next on-Island dispatchable generator, sized around 50-75 MW, as it is an existing industrial site and most of the generator's ancillary needs are already on site.

The right of way between the Charlottetown Plant site and the Charlottetown Harbour should be maintained to allow future access to the Harbour's heat sink capabilities if and when it is required. The River Pumphouse should be removed as it is no longer required and is in need of significant repair, and the underground services between the Plant site and Charlottetown Harbour should remain in place as they would be unseen by the public. The existing rock groyne should be left in place for potential future site cooling requirements. The alternative is to locate future generation or storage equipment elsewhere and use groundwater as the cooling medium, which may not be available in the required quantities.

The Charlottetown Plant site should also be capable of a 138 kV connection that can provide a supply to downtown and eastern.

11. LONG-TERM VIEW OF SYSTEM NEEDS

Maritime Electric continues to look at longer term system issues, and uses it as a guide for developing needed programs and infrastructure deployment.

Continued replacement of 138/69 kV transformers

The 138/69kV 50MVA transformers will be replaced with larger 75MVA transformers, with the replacements being driven by equipment condition and loading.

Replacement of the Borden Generation Station Facilities

The two Borden generators were installed in 1971 and 1973 and will be obsolete by the end of the decade. Maritime Electric is nominally scheduling their replacement for 2030 when the two units will be almost 60 years old. Locating replacement generation in Borden may make use of existing system facilities, but it is likely not the best location for this generation on the system. Siting generation close to load centres and transmission substations brings more reliability, maintenance and operational benefits. Locating a Borden replacement close to the Sherbrooke substation could also provide additional system benefits.

Replacement of Original Submarine Cables

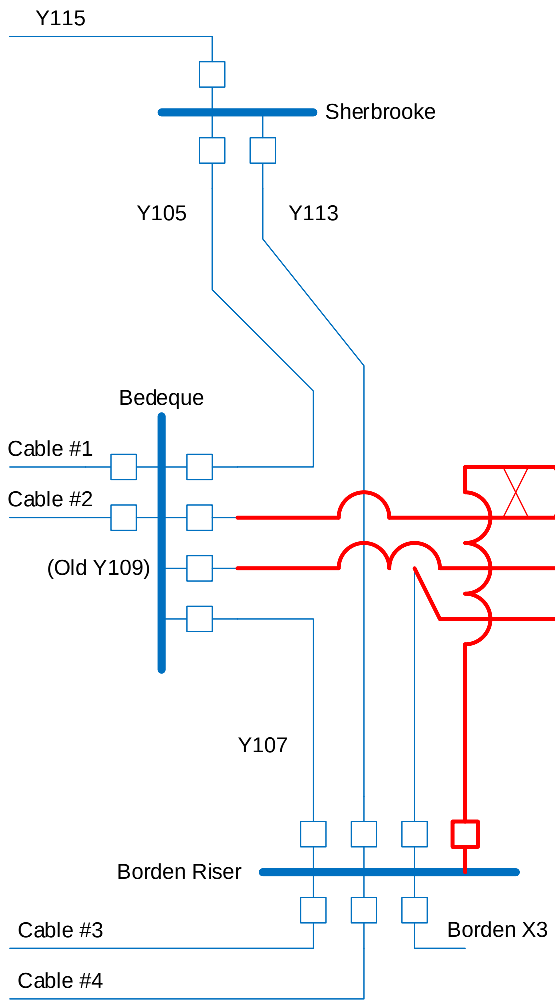
Cables # 1 and #2, along with lines Y-101 and Y-103, were installed in 1977 and are capable of either DC (200 kV) or AC (138 kV) operation. While Cables #3 and #4 were built for 138 kV operation, the potential of high voltage DC transmission into the Moncton area means that high voltage DC should be considered as possible Island connection in the future. A long-term outlook of the system's needs and supply options is necessary when looking at replacing Cables #1 and #2 to ensure that the optimal connection to the mainland is constructed.

Rebuild of line Y-111

Y-111 is anticipated for rebuild around 2030, by which time the impacts of electrified transportation may be more apparent. Consideration should be given to building a double circuit steel tower for at least a portion of the length if long-term projections show large increases in both energy and demand in eastern PEI.

The 1977 connection between PEI and New Brunswick opened PEI up to mainland energy and capacity markets. At the time, the 138 kV infrastructure was built with considerable surplus thermal capacity to allow the system to grow without additional step infrastructure needs. The addition of Cables #3 and #4 in 2016-17 accomplished the same, as additional submarine capacity will not be needed for some time. A double circuit steel tower to replace Y-111 would maximize the use of the Y-111 right of way, and would provide sufficient thermal capacity for decades. The existing Y-111 right of way can accommodate a double circuit steel tower from Bedeque to West Royalty. One potential configuration is shown in Figure 13.

Figure 13 Y-111 Double Circuit Connections



Rebuilds of Y-105, Y-107 and Y-113

Lines Y-105, Y-107 and Y-113 are currently operated using 477 MCM Hawk conductor with a thermal capacity of 160 MVA. These lines are relatively short and voltage drop over the length is not a concern. Larger conductor – 740 AAAC Flint or other – should be used when these lines are rebuilt to increase the lines' thermal loading capabilities and reduce overall system losses.

Conversion of Distribution Substations to 138 kV

Increasing system loads will lead to higher 69 kV system loading. A 69 kV line has four times as many losses as a 138 kV line for a similar power transfer. Consideration should be given to constructing distribution substations at 138 kV that are located on or close to 138 kV facilities when either building new or rebuilding existing stations. This will help offload 138/69 kV transformers and help minimize system losses.

Relocating sections of Y-115

Line Y-115 was designed and built in 2008 in a short timeframe under considerable pressure from wind farm project proponents. Portions of it were routed through wet, inaccessible land as that was the only option given the limited timeframe. The line has had reasonable reliability up to this point.

Repair and replacement of sections between Portage and O'Leary will be expensive as corduroy roads will have to be rebuilt in order to access the area, and specialized tracked vehicles will be required for access. Moving these sections out to the roadside should be investigated to see if relocation is a long term lower cost option.

West Royalty Substation Long-Term Options

The West Royalty substation is one of the key stations on the system. It is currently the only substation that contains four voltage levels – 138 kV, 69 kV, 25 kV, and 13.8 kV – and is space constrained with little room to expand its existing facilities. There is one 138 kV bay left which will be used for transformer upgrades. The distribution yard (69/25 kV and 69/13.8 kV) is constrained and has few options for expansion or rebuild. West Royalty needs to be flexible in the long-term to meet the future changing needs of the system given this substation's key role in both load-serving in the Charlottetown area as well as serving as the main transmission hub for eastern PEI.

138 kV Source to Charlottetown Substation

The Charlottetown Substation is the key substation serving downtown and eastern Charlottetown. It connects to existing CT3 generation, and is the preferred site for an additional combustion turbine in the Charlottetown area. Certain 69 kV bus outages in West Royalty require the entire West Royalty 69 kV supply to be cut to Charlottetown, meaning that Charlottetown has to be supplied through Church Road via Y-104. This can be accomplished without CT3 operation only at light low loading periods – overnight times in the spring during the system's lightest loading conditions – as the system is very weak when supplied from that distance. The addition of a Lorne Valley 138 kV source will help with system strength in that configuration, but with the growing system load the system will still be relatively weak when the West Royalty 69 kV source is cut off.

Converting T-15 to 138 kV, or tapping Y-104 and connecting it to a 138 kV source at Charlottetown are potential solutions to bringing the 138 kV supply to Charlottetown. It will significantly strengthen the supply to Charlottetown, and will allow the West Royalty 69 kV bus to be taken out of service during more periods of the year for planned or emergency maintenance without any customer interruptions.

System Maps – Present to Long Term

The following maps of the 138 kV and 69 kV systems are presented as a conceptual vision of the system up to 2030.

Figure 14 Present System Single Line

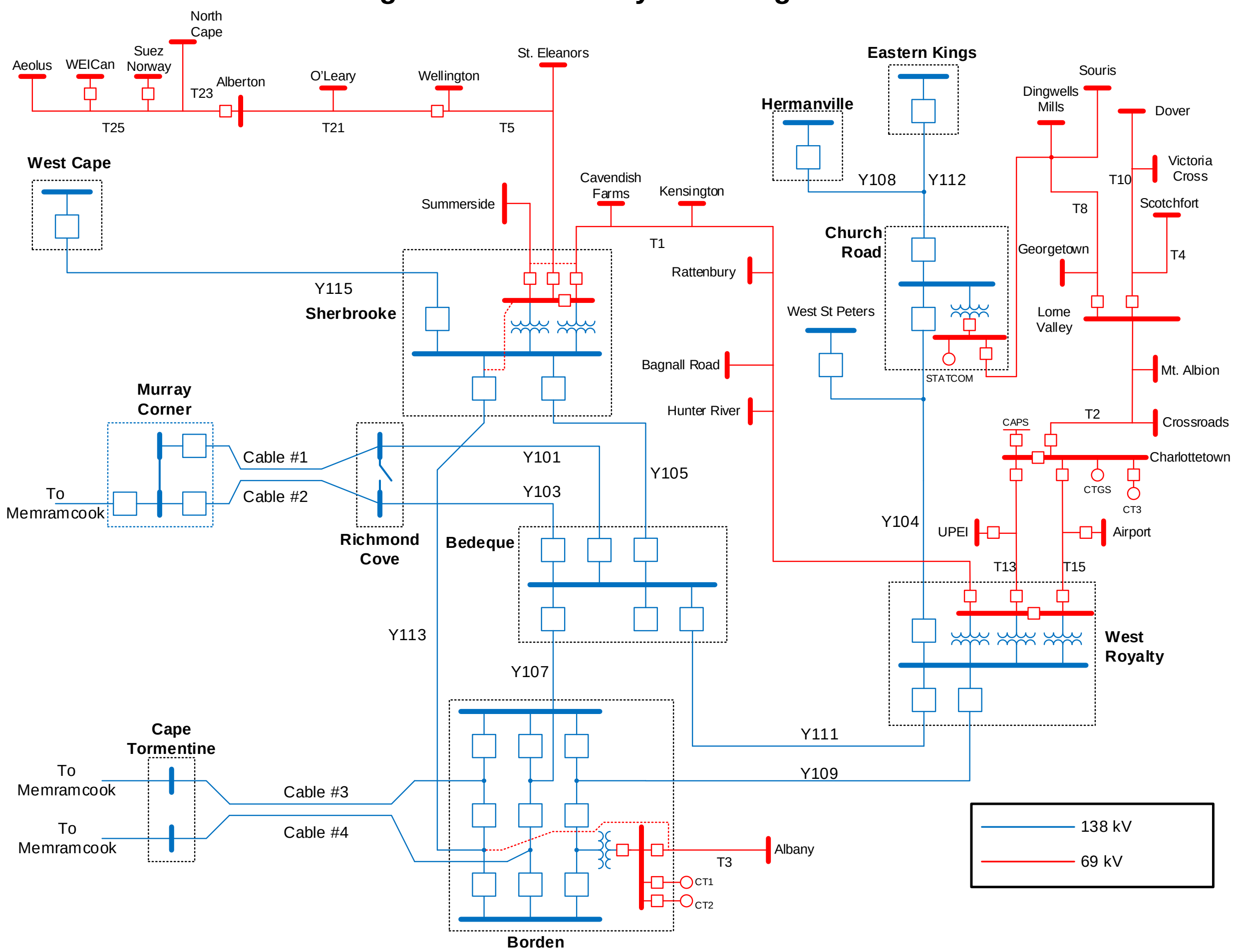


Figure 15 2025 System Single Line

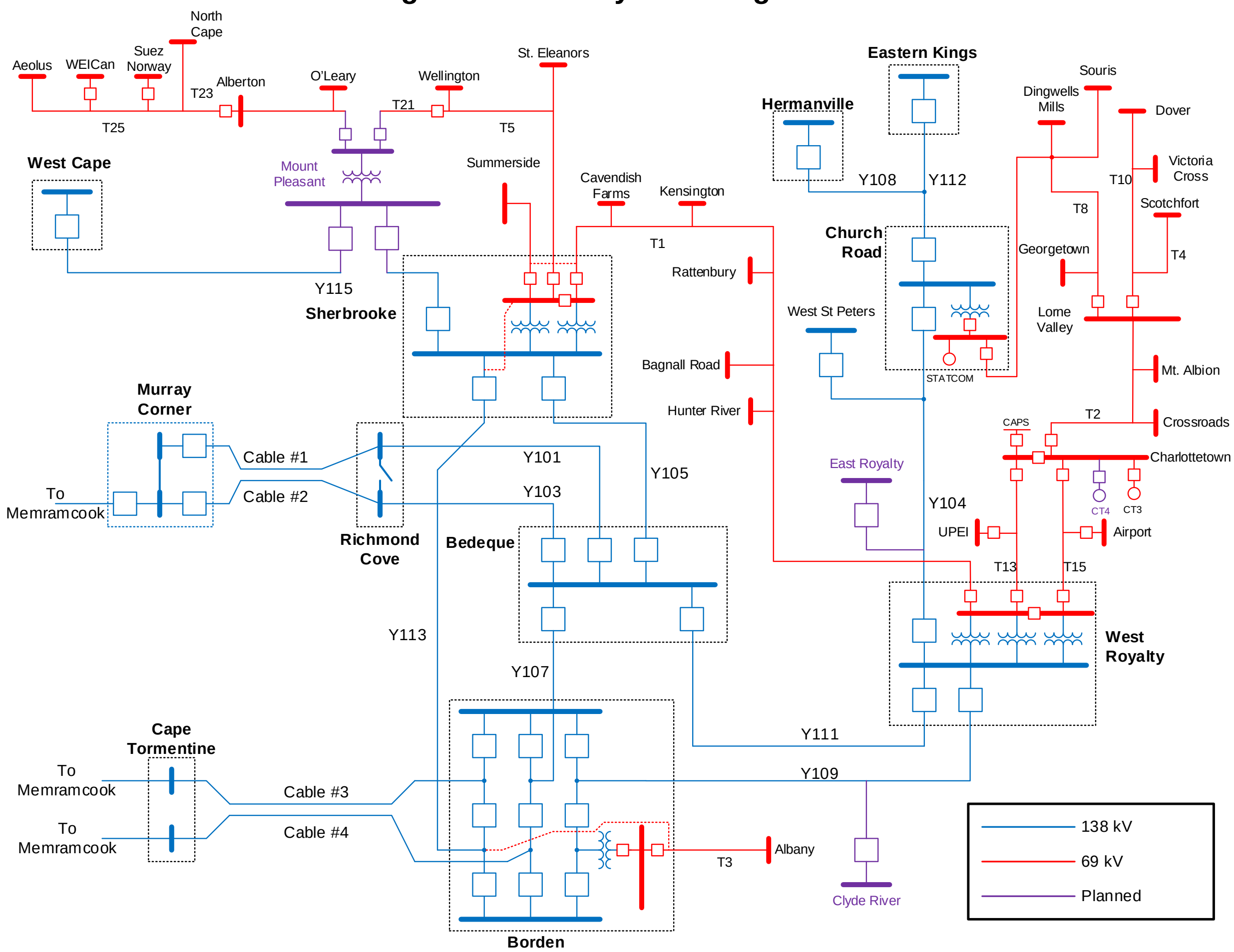


Figure 16 2030 System Single Line

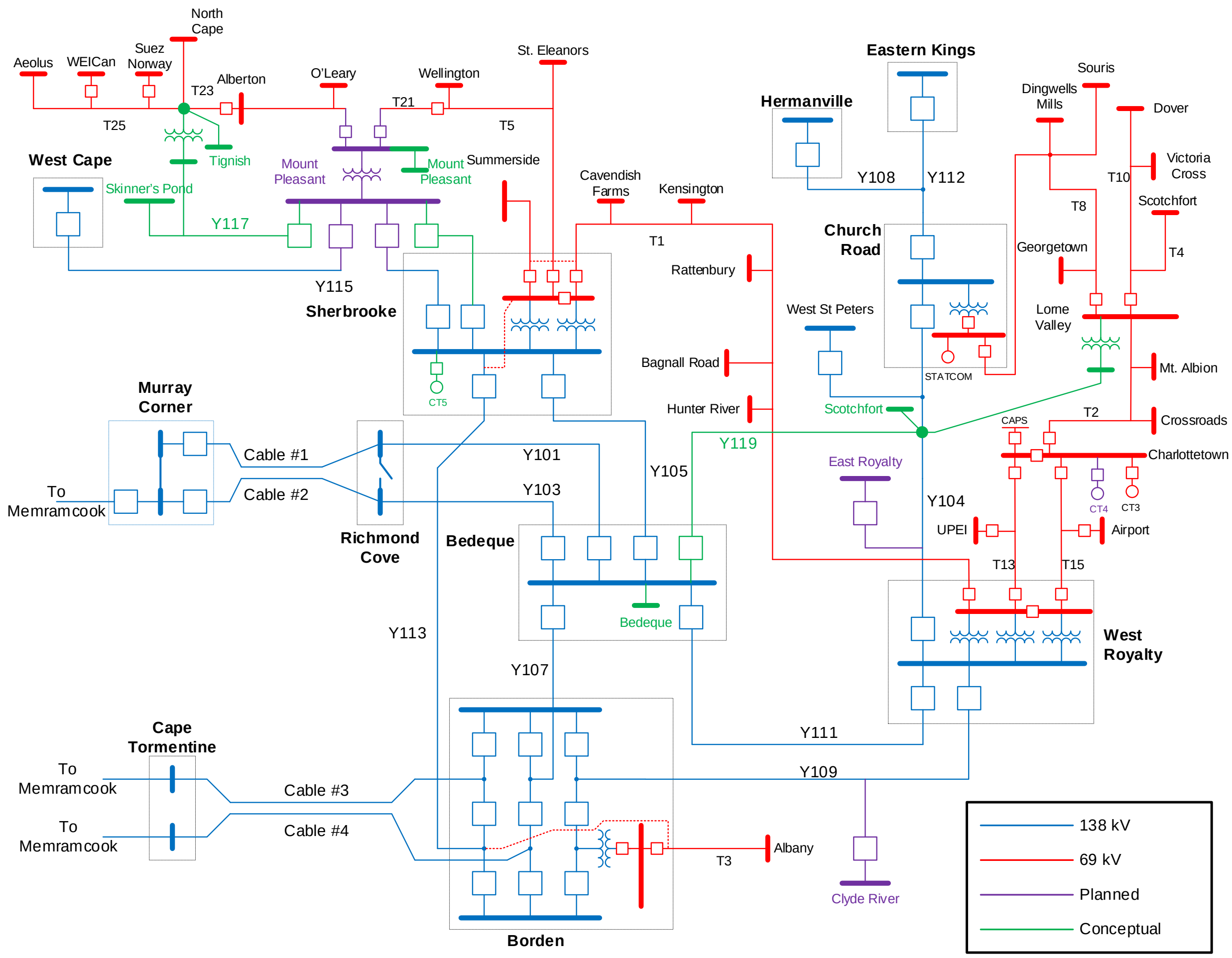


Figure 17 Existing 138 kV System Map

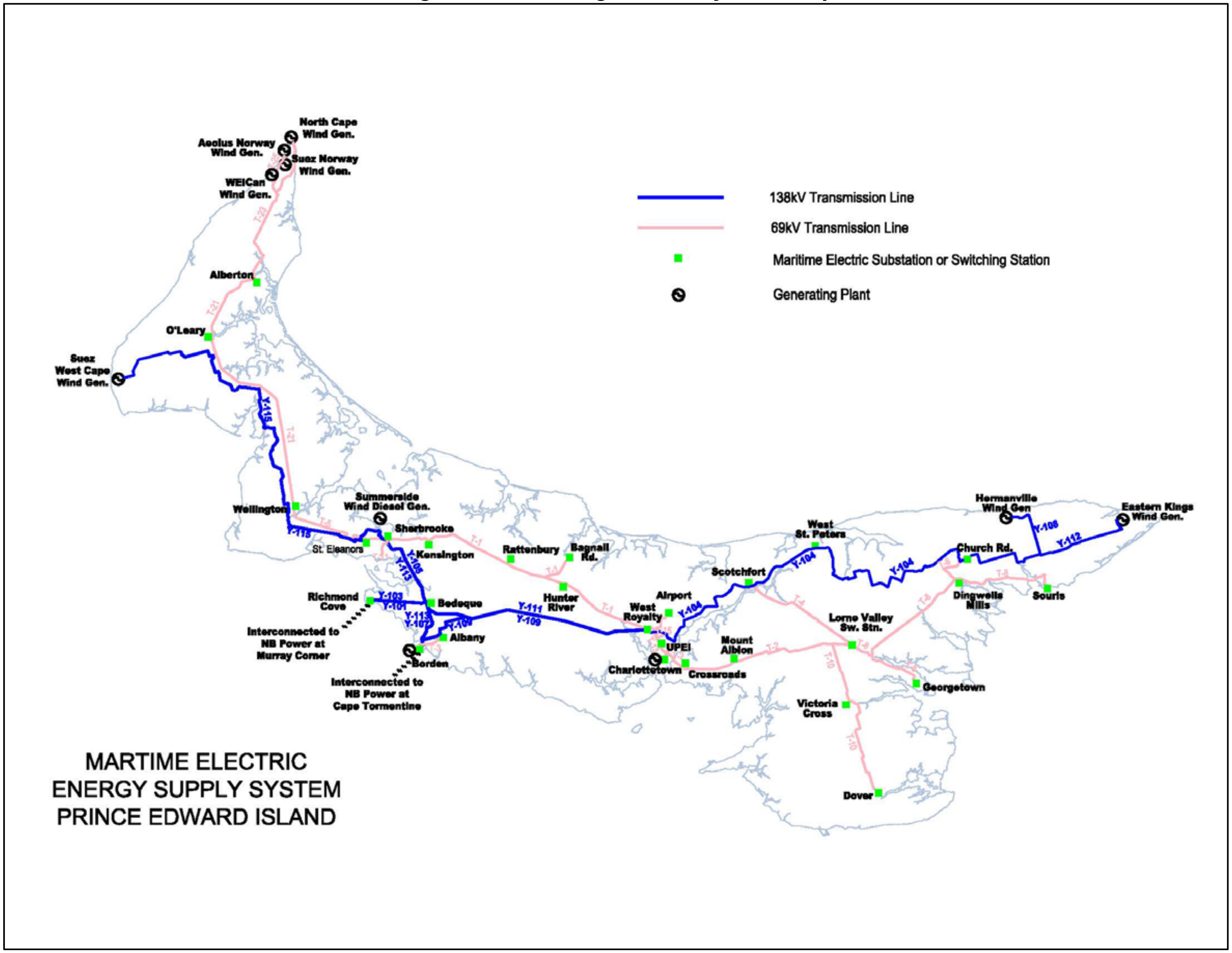
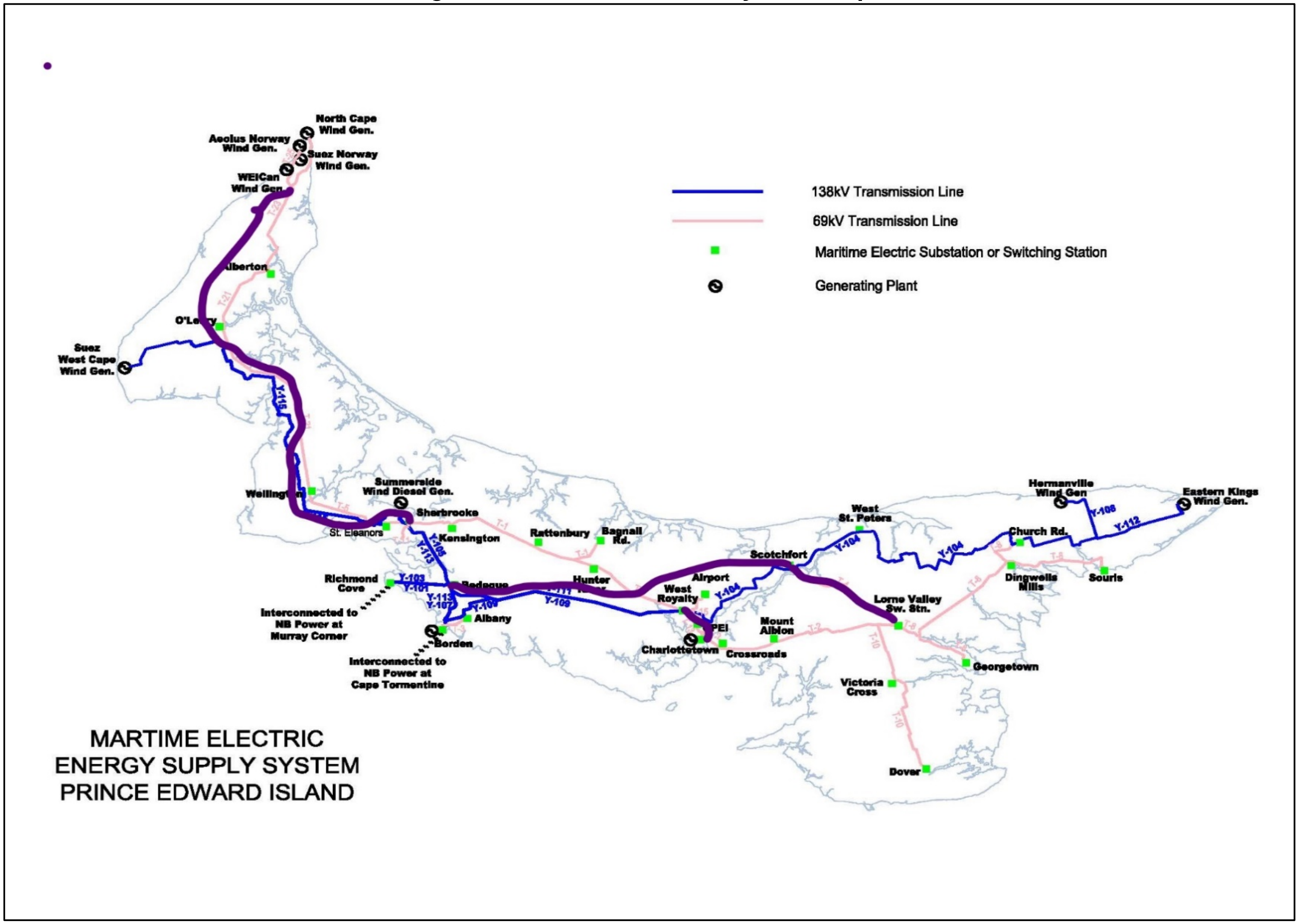


Figure 18 Ultimate 138 kV System Map[70]



70 Purple lines represent additional 138 kV transmission lines

12. CRITICAL SPARES

Maritime Electric carries a supply of critical spare parts and equipment that can be readily dispatched into service when required. The type and quantities are based on a variety of factors including cost, availability, estimated likelihood of need, ease of transport, and impact on customer reliability.

Maritime Electric has agreements with some suppliers to hold critical spare parts and equipment at supplier facilities when that option is the most cost-effective. Maritime Electric continuously reviews its spare parts and equipment on hand to improve customer reliability in a cost-effective manner.

Most of Maritime Electric's equipment can be quickly replaced in the case of a failure depending on weather conditions and accessibility to the failed equipment. There are sufficient inventories of poles, conductor and transformers both on-Island and in the Maritimes to accommodate most situations. In the rare case of atypical equipment, Maritime Electric stores sufficient spares on site. For example, Maritime Electric stores spare parts, splice kits and cable lengths for the subsea cables that interconnect PEI to New Brunswick.

There are, however, several large pieces of equipment that Maritime Electric does not carry critical spares for and that have significant lead-times in the case that a replacement is needed. In the case that large existing equipment is replaced to improve reliability, Maritime Electric sometimes opts to keep the existing equipment in storage or in "hot-standby" as a spare if it is economical to do so. Table 30 below details large equipment for which Maritime Electric does not carry spares for, along with projected replacement times.

Table 29 Long Lead Time Items			
Equipment	**Component**	**Outage Time**	**Comment**
CT1, CT2	Gas Turbine	2-12 months	CT1 & CT2 are old turbines and no spares are available. Many parts have to be custom-made.
	Generator	12 months	Generators are custom-made and require exact sizes, footprints and bolt prints to be interchanged.
	Transformer	6-12 months	This size of the generator transformer is unusual. The time to rectify a core failure requiring a complete replacement or rebuild depends on factory availability.
	Control System	8-12 months	Control systems are obsolete and spare parts are no longer available.
CT3	Gas Turbine	1-6 months	Maritime Electric does not pay an annual fee to be in a 'spare turbine' pool. Maritime Electric would require a new turbine to be scheduled and built if one is not readily available.
	Generator	12 months	Generators are custom-made and require exact sizes, footprints and bolt prints to be interchanged.
	Transformer	6-12 months	This is an atypical generator transformer due to on-load taps. It is custom-made and there are very few (if any) spares available in North America.
	Control System	8-12 months	Some spare parts available, however, the system is becoming obsolete and the loss of a major component would inhibit operation for an extended period.
Sherbrooke, Borden, West Royalty, Church Road	138/69kV transformers	6-12 months	No spares located on-island. Spares may be available somewhere in North America; otherwise, a new transformer would need to be designed, ordered, built and installed.
Borden, Bedeque	Reactors	6-12 months	No spares located on-island. Spares may be available somewhere in North America; otherwise, a new reactor would need to be designed, ordered, built and installed.

The loss of these long lead time items can impact the system during both summer and winter peaking, as well as during periods of system maintenance and repair.

Outages to CT1 and CT2 are no longer as severe since Cables #3 and #4 were installed. However, due to their locations, outages to CT3 and/or the West Royalty Substation can be much more severe. The failure of a CT3 component or a West Royalty 138/69kV autotransformer can interrupt Eastern PEI customer supply until system conditions permit load reinstatement. The difficulty with outages related to the loss of equipment with long lead times is that it can repeatedly impact customer supply over a long duration until the system seasonal load level drops to more manageable levels.

In the case of a major failure to CT1, CT2 or CT3, leased engines can be obtained from suppliers, however, availability is often limited and the cost is typically high. Leased engines can be installed in 4-8 months after an agreement is signed with a supplier.

13. SUMMARY

Maritime Electric integrates its generation, transmission, and distribution planning in order to provide reliable and safe service at the most economic cost of energy to customers. Corporate services such as fleet and information technology also require ongoing upgrades and replacements, however these services, while important, are not as intricately linked as the first three.

The large-scale capital additions scheduled over the medium- to long-term are summarized in Tables 30 and 31. Note that some projects are load-driven, and timing depends on rate of load growth. Other projects are age- or condition-related, and timing is independent of Island load growth patterns.

Table 30
Summary of Capital Projects Up to 2025

Projected Year of Need[71]	Project
Generation Projects	
2024	Additional 50-75 MW Combustion Turbine
Transmission Projects	
2021-2023	Replace end of life Y-109 with Y-119
2022	East Royalty Substation tap line
2023	West Royalty – replace transformer X5 with 75 MVA unit
2024	Western 138/69kV transformer and substation
2024	Line T11 – rebuild
Distribution Projects	
2022	East Royalty Substation

[71] Based on current load forecast

Table 31 Summary of Potential Capital Projects Post 2025	
Projected Year of Need	**Project**
Generation Projects	
2030	CT1 and CT2 replacement
Transmission Projects	
2026	West Royalty – replace transformer X6 with 75 MVA unit
2027+	Line Y105, Y-107 and Y-111 Rebuilds
2027+	Third West-East transmission line & Scotchfort Switching Station
2028+	138 kV connection to Lorne Valley; 138 kV source at Lorne Valley
2030+	138 kV Connection to Charlottetown Substation, Charlottetown Substation rebuild
Distribution Projects	
2026	Mount Pleasant – new substation
2026	Tignish substation
2027+	Cavendish substation
2028+	Scotchfort 138/12.5 kV substation
2029+	Bedeque area 138/12.5 kV substation
2029+	Charlottetown area 13.8 kV transformation capacity, if not included with additional Charlottetown-area generation

Appendix A – Transmission Line Data

Maritime Electric Transmission Lines					
Name	**Voltage**	**Location**	**Built**	**Length**	**Conductor**
T1	69kV	West Royalty to Sherbrooke	1983	58.3	477 ACSR - Hawk
T2	69kV	Charlottetown to Lorne Valley	1989	36.0	477 ACSR - Hawk
T3	69kV	Borden to Albany	2019	4.6	4/0 ACSR - Penguin
T4	69kV	Scotchfort to Lorne Valley	1969	20.8	4/0 ACSR - Penguin
T5	69kV	Sherbrooke to Wellington	1996-2003	19.2	2/0 ACSR - Quail
T8	69kV	Lorne Valley to Georgetown, Dingwells Mills, Souris	1999-2011	63.6	477 ACSR - Hawk, 4/0 ACSR - Penguin
T10	69kV	Lorne Valley to Dover	1989-1994	33.4	4/0 ACSR - Penguin
T11	69kV	Summerside to Sherbrooke	1963, 1997	3.6	2/0 ACSR - Quail
T13	69kV	West Royalty to Charlottetown	1983	6.2	477 ACSR - Hawk
T15	69kV	West Royalty to Charlottetown	1986	12.5	477 ACSR - Hawk
T21	69kV	Alberton to O'Leary	2003-2008	52.1	477 ACSR - Hawk
Y104	138kV	West Royalty To Church Road	2017	83.1	740 AAAC - Flint
Y105	138kV	Bedeque to Sherbrooke	1971	15.4	477 ACSR - Hawk
Y107	138kV	Bedeque to Borden	1971	8.3	477 ACSR - Hawk
Y108	138kV	Y112 to Hermanville	2013	10.3	477 ACSR - Hawk
Y109	138kV	Borden to West Royalty	1979	50.9	740 AAAC - Flint
Y111	138kV	Bedeque to West Royalty	1987	41.1	740 AAAC - Flint
Y112	138kV	Church Road to Eastern Kings	2006	34.7	477 ACSR - Hawk
Y113	138kV	Borden to Bedeque	1991	23.8	477 ACSR - Hawk
Y115	138kV	Sherbrooke to West Cape	2008	84.9	740 AAAC - Flint
			Total	662.7	

PEI Energy Corporation Transmission Lines					
Name	**Voltage**	**Location**	**Built**	**Length**	**Conductor**
T23	69kV	Alberton to North Cape	2001	28.4	4/0 ACSR - Penguin
T25	69kV	Christopher Cross to Norway	2003	7.5	4/0 ACSR - Penguin
Y101	138kV	Richmond Cove to Bedeque	1978	9.7	954 ACSR - Cardinal
Y103	138kV	Richmond Cove to Bedeque	1978	9.8	954 ACSR - Cardinal
			Total	55.5	

Appendix B – LoadFlow Study Results

Load Level (MW)	Projected Year	Issue Description	Potential Solutions
Various	Existing	Cannot supply various load due to maintenance outages	Building of reliability and redundancy in system will gradually reduce this exposure
240	Existing	Cannot supply Crossroads and Mt. Albion for loss of T-2 between Charlottetown and Crossroads	138 kV source into Lorne Valley will resolve this issue
294	2020	Assumes Clyde River substation in service	
		Need on-Island generation operating to keep NB-NS/PEI interface below maximum levels	Wind can offset imports up to the point when voltage-based issues require dispatchable generation to operate
		WR autos at 102% with X5 out, CT3 output at 45 MW	Allow 10% overload on all 138/69kV transformers as peaking conditions are short-duration during cold temperature periods
		Sherbrooke autos at 100% with T-1 open at Rattenbury	System studies show more issues if T-1 open point shifted west, so open point has to remain at Rattenbury.
		Loss of Y-111 at peak can cause low eastern PEI voltages	Undervoltage load shedding (UVLS) may be initiated in short term to support system voltage; load can be restored after CT3 is started
		Loss of Y-104 at peak causes West Royalty autos to load to 111%	Start CT3 to offload West Royalty autos
304	2021	Various N-1 operational issues	All can be resolved with existing facilities
312	2022	Cannot supply Crossroads and Mt. Albion for loss of T-2 between Charlottetown and Crossroads	138 kV source into Lorne Valley will resolve this issue
		Loss of Y-111 at peak without eastern generation operating puts eastern PEI on verge of voltage collapse; Y-109 loads to 108%	UVLS required unless generation is operated preemptively; CT3 resolves voltage and Y-109 loading issues
		Loss of Y-104 at peak causes West Royalty autos to load to 118%, eastern voltages between 90-94%	Start CT3 to offload West Royalty autos
		Loss of T-1 between Hunter River and West Royalty leads to Sherbrooke auto loading at 126% after closing T-1 loop	Dispatch all Summerside diesels reducing Sherbooke loading to 110%; longer-term issue may require Y-113 conversion to 69kV.
321	2023	Assumes East Royalty substation in service	

		Need minimum 25MW of generation to keep interchange loading under 300MW	
		Sherbrooke autos at 110% with no western 69kV wind operating	
		Loss of Y-104 at peak causes West Royalty autos to load to 113%, assuming East Royalty substation in service	Dispatch CT3
		Loss of T-1 between Hunter River and West Royalty leads to Sherbrooke auto loading at 130% after closing T-1 loop	Dispatch all Summerside diesels reducing Sherbooke loading to 114%; in short-term Summerside needs to shed load to reduce Sherbrooke loading to 110%; in longer-term Y-113 can be converted to 69kV.
		May need all reactors out of service to support voltages in western PEI	Add distribution capacitors or western 138/69kV source
329	2024	Assumes O'Leary/Mount Pleasant 138/69kV substation in service	
		Need 35 MW of generation operating to keep interface under 300 MW	
		Loss of Y-111 at peak without eastern generation operating likely collapses eastern PEI	Significant load shedding required, or alternatively eastern generation (wind, dispatchable) needs to be operating prior to loss of Y-111
		Loss of T-1 between Hunter River and West Royalty leads to no issues with western 138/69 kV source in service	
		Outage to O'Leary/Mount Pleasant 138/69 kV transformer leads to low western voltages	Distribution capacitors in selected locations likely alleviates the issue
337	2025	Need 45 MW of generation operating to keep interface under 300 MW	
		West Royalty autos load to 100% under no contingency situations with no eastern generation operating	
		Loss of Y-104 at peak with no eastern generation operating - West Royalty autos load to 121%; eastern voltage between 93-96%	Dispatch only generator east downstream from autos – CT3
		Loss of T-1 between Cavendish Farms and Sherbrooke – low voltages seen at western end of T-1	Reactive power support needed somewhere on T-1, such as Bagnall Road or Rattenbury; closer to the end would cause larger local voltage change when opening/closing reactive power source

		O'Leary auto outage loads Sherbrooke autos to 116%; low western voltages	Short-term Summerside operate generation to reduce its non-firm load; longer term convert Y-113 to 69kV; western distribution capacitors will help support voltage
353	2027	Need 60MW of dispatchable generation on-Island to keep interchange below 300 MW. If CT3 out of service, isn't sufficient remaining dispatchable generation on-Island to keep interface below 300MW.	Additional on-Island generation will relieve this issue; if not present then interruptible customers will have to be shed.
		Loss of Sherbrooke transformer – remaining transformer overloads to 106% even with CT2 operating at full output and Y-113	This may be the point where Sherbrooke transformer should consider being upgraded if transformer condition dictates transformer is 51 years old and reaching maximum output
		Loss of Y-111 leads to voltage collapse and Y-109 overloading	Require eastern generation to be operating. Synchronous condenser and reactive power devices help with voltage issues, but do not relieve thermal loading issues. Need additional generation and/or a third west-to-east line in place.
		O'Leary auto outage loads Sherbrooke autos to 121%; low western voltages	Short-term Summerside operate generation to reduce its non-firm load; longer term convert Y-113 to 69kV; western distribution capacitors are needed to support voltage
375	2030	Need 80MW of dispatchable generation on-Island to keep interchange below 300 MW.	Additional on-Island generation will relieve this issue; if not present then interruptible customers will have to be shed to keep interface at maximum available levels.
		Loss of CT3 leads to West Royalty auto loading at 108%, low eastern PEI voltages	No way to offload transformers or support voltage with CT3 offline
		Loss of Y-104 when western wind + Borden generators operating; West Royalty transformers load to 135%; eastern voltages range 89-93%	With CT3 operating at full output, West Royalty transformers still load to 107%. A third source into eastern PEI (138kV to Lorne Valley) or second eastern dispatchable generator are required

Appendix C – Maritime Electric Substation Peaks 2019

Substation	Feeder (if applicable)	Peak Feeder Load (MW)	Peak Substation Load (MW)
Alberton	Alberton Cct	4.28	
	Tignish Cct	7.94	
O'Leary			10.15
Wellington			8.92
St. Eleanors			6.43
Albany			14.14
Kensington			12.27
Rattenbury			6.21
Hunter River			6.65
Bagnall Road			7.71
West Royalty 25kV	Bonshaw	21.34	
	Milton Brackley	15.46	
Airport			8.05
West Royalty 13.8kV			19.80
Charlottetown			29.92
UPEI			14.66
Scotchfort			5.38
West St. Peters			7.75
Crossroads			17.16
Mount Albion			3.62
Victoria Cross 12.47 kV			6.22
Victoria Cross 24.94 kV			6.45
Dover			4.45
Gerogetown			5.66
Dingwells Mills			5.23
Souris			7.45
Non-Coincident Total Peak (MW)	**249.2**		

Appendix D – Relocating CT3 Costs (2015$)

	Option 1. GIS substation at Charlottetown Plant, generating station on outskirts of City						
	Option 2. Move all infrastructure from Charlottetown Plant to outskirts of City						
		Option 1			**Option 2**		
		Unit Cost	**# units**	**Total Cost**	**Unit Cost**	**# units**	**Total Cost**
Site Development	Land Purchase	$200,000	15	$3,000,000	$200,000	20	$4,000,000
	Site work	$400,000	1	$400,000	$400,000	1	$400,000
	Substation infrastructure	$500,000	1	$500,000	$500,000	1	$500,000
	Substation Building	$200,000	1	$200,000	$200,000	2	$400,000
	69kV breakers	$400,000	4	$1,600,000	$400,000	3	$1,200,000
	Communications	$300,000	1	$300,000	$300,000	1	$300,000
Generation Costs	Move CT3	$25,800,000	1	$25,800,000	$25,800,000	1	$25,800,000
	Additional CT4 install costs	$1,000,000	1	$1,000,000	$1,000,000	1	$1,000,000
	Additional 60MVA GSU	$1,200,000	1	$1,200,000			$ -
Distribution	13.8kV switchgear			$ -	$800,000	1	$800,000
	13.8kV breakers	$30,000	2	$60,000	$30,000	5	$150,000
	69/13.8kV transformer, 30MVA	$600,000	2	$1,200,000	$600,000	2	$1,200,000
	Water supply			$ -	$500,000	1	$500,000
	Transfer feeders from CTGS to switchgear	$200,000	1	$200,000			
	13.8kV Lines			$ -	$50,000	29	$1,450,000
	Reconductor 13.8kV lines			$ -	$50,000	10	$500,000
Plant GIS	Breakers	$500,000	4	$2,000,000			$ -
	Bus	$1,000,000	1	$1,000,000			$ -
	Building	$500,000	1	$500,000			$ -
	Infrastructure	$500,000	1	$500,000			$ -
	Connections	$500,000	1	$500,000			$ -
Demolition	Plant site demolition, greenfield	$10,000,000	1	$10,000,000	$10,000,000	1	$10,000,000
Transmission	Transmission Line, 477MCM	$120,000	6	$720,000	$120,000	6	$720,000
	IDC	$2,000,000	1	$2,000,000	$2,000,000	1	$2,000,000
	Total			$52,680,(			$50,920,(

Notes:
1. Development costs are assumed to be included in CT4 budget (EIA, regulatory, legal, permitting, Maritime Electric salaries, etc.)
2. Plant site demolition assumes substation, fuel storage, CTGS building removed, stacks down, asbestos abatement, site levels and landscaped afterwards.
3. GIS sub assumed to go between X4 and Charlottetown Substation. CTGS buildings, etc. come down.
4. Holland College can use additional parking up to 13.8kV switchgear, X4, GIS substation; south side of GIS/switchgear becomes green space. Essentially occupy Richmond St to Sydney Street, all the way through existing Plant site
5. Site reclamation does not include environmental costs for land (fill, sub-surface, etc.).