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The Island Regulatory and Appeals Commission

October 31, 2024

Ms. Cheryl Bradley, CPA, CA
Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Ms. Bradley:

UE20741 – 2025 Capital Budget Application
Clarification Questions

Please find attached the Company's responses to clarification questions from Mr. Roger King with respect to the 2025 Capital Budget Application filed with the Commission on August 2, 2024.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

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

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All our energy.
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Via email: rdking519@gmail.com

October 31, 2024

Mr. Roger King
519 Simpson Mill Rd
Hunter River PE C0A 1N0

UE20741 – 2025 Capital Budget Application
Clarification Questions

Please find attached the Company's response to your clarification questions with respect to the 2025 Capital Budget Application filed with the Commission on August 2, 2024.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

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

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INTERROGATORIES

Responses to Interrogatories
of
Roger King

2025 Capital Budget
Clarification Questions
(UE20741)

Submitted October 31, 2024

Context of Questions:

1. An added complexity of this application is that the Supplemental Capital Budget Request: Advanced Metering for Sustainable Electrification Project Application – UE20737 tabled in November, 2022 remains under consideration by IRAC. Capital expenditures identified in UE20737, occurred last year (2023) and are included and changed for 2024 and 2025 in Appendix A of this application. As a result, some questions relevant to UE20737 are also tabled here.

2. One significant planned capital expenditure included last year as a "place holder Item" in Exhibit A – New Generation – is now excluded, and a new cluster of interdependent projects amounting to $40M, starting in 2025 is introduced. Hopefully an opportunity to seek details of both high cost projects separately will become available soon.

Clarification Questions:

IR-1 Appendix A shows that the budgeted allocation from the Advanced Metering for Sustainable Electrification Project Application – UE20737 – is now essentially reduced to two years, 2024 and 2025; additionally the expenditures also appear to have changed from Exhibit M10 of UE20737. Please provide a table showing the comparison between Appendix A data and Exhibit M10 and provide a detailed description of the changes including the reduced time schedule and planned 2024 expenditures.

Response:

The budget amounts for the Advanced Metering for Sustainable Electrification ("AMSE") project in Appendix A of the 2025 Capital Budget Application are the same as in Exhibit M10 of the ASME project application. The absence of footnotes in Appendix A for the years 2026 and 2027 may have confused this matter. For clarity and to facilitate reconciling the Appendix A and Exhibit M10 annual budget amounts as the same, supplementary notes for Appendix A follow.

- 2026 Distribution total includes $3,657,000 for the Advanced Metering Infrastructure ("AMI") component of the AMSE project.
- 2026 Corporate total includes $6,865,000 for the Customer Information System ("CIS") component of the AMSE project.
- 2026 Interest During Construction ("IDC") total includes $1,140,000 for the AMSE project.
- 2027 Corporate total includes $2,371,000 for the CIS component of the AMSE project.

These notes are also included in an amended Appendix A, provided as part of the response to IR-7, herein.

IR-2 Section 5.6 – System Meters – shows a continued deployment of RI meters as for previous years. To provide context of one segment of a growing customer population please provide the historical numbers and type of meter that have been deployed for Net Metering sites, i.e. Residential and Commercial (Combination Meter) customers, and describe how this metering will be phased over to the AMI infrastructure in the future. Also describe how the features of the smart meters will be utilized for both the IN and OUT meters, particularly for the Commercial (Combination Meter) customers.

Response:

Net metering installations have been accelerating since the Provincial Government's Solar Electric Rebate Program began in August 2019. Prior to 2019, there were a total of 215 net metering customers. Today there are more than 4,000.

Table 1 shows the annual addition of net-metering installations to Maritime Electric's system over the past ten years.

TABLE 1
Annual Net-Metering Installations

Year	Net-Metering Installations	Watt-Hour (non-demand) Meters	Combination (demand) Meters
2015	35	30	5
2016	38	37	1
2017	37	37	0
2018	49	45	4
2019	62	60	2
2020	265	263	2
2021	488	472	16
2022	1,033	1009	24
2023	1,287	1258	29
2024[a]	777	743	34
TOTAL	**4,071**	**3,954**	**117**

a. 2024 installations are as of September 30, 2024

With the recent approval of the AMSE project, the process of planning the transition to AMI is now underway but the detailed transition plan is not yet finalized. At this time, it is expected that net-metering customers will be converted to AMI at the same time as their neighbours, in accordance with the final transition plan.

The Company's General Rules and Regulations approved by the Commission stipulate that two meters are to be used for net-metering installations. As part of the detailed transition plan, the need for two meters will be reviewed. It is anticipated that one meter will technically be sufficient to serve net-metering accounts; however, modifications to the current General Rules and Regulations would be required.

There will be no notable changes in the way the net-metering information is processed for Commercial and Non-Commercial net-metering customers, with the exception that significantly more data will be collected and stored for both the delivered and received meter channels.

IR-3 Related to question 2, please provide sample monthly billing calculations for the condition when monthly excess renewable energy generated is a kWh credit carry forward for both the Residential and Commercial customers, e.g. is the energy credit based upon a monthly net zero, dollar billing amount or on a net zero energy used basis? How does Net Metering affect Demand billing?

Response:

For net metering, the energy credit is applied on a net-dollar-billing basis. Table 2 shows an example monthly bill for a Residential customer. The example is based on a delivered meter reading of 1,431 kWh and a received meter reading of 1,500 kWh for the month.[1] That month's bill would reflect a credit for 1,431 kWh that fully offsets the energy delivered for that month, because the energy was actually self-supplied. That customer's account would also reflect an unused credit for 69 kWh (i.e., the difference between what was delivered and received) that is carried forward to apply as a credit on a future bill, when the energy delivered exceeds the energy received.

TABLE 2 **Example of a Residential Net Metering Customer's Bill**	
Service charge: $24.57/month	$ 24.57
First block energy: 1,431 kWh x $0.1667	238.55
Second block energy: 0 kWh x $0.1332	0.00
Subtotal	**263.12**
HST: $263.12 @ 15%[2]	39.47
PEI Government energy rebate: $238.55 @ 10%	(23.86)
Net metering credit: 1,431 kWh x $0.1667	(238.55)
Total bill for current month	**$ 40.18**

Table 3 shows an example monthly bill for a General Service customer. The example is based on a delivered meter reading of 6,080 kWh and 38.7 kW, and a received meter reading of 5,720 kWh for the month. That month's bill would reflect a credit of 5,720 kWh, only partially offsetting the energy delivered. There is a net metering HST credit because the customer is an HST registrant. Net metering has no effect on the demand billing.

1 The terminology of delivered and received is from the Company's perspective. Delivered means supplied to the customer and received means supplied to the Company.

2 As is the case for most Residential customers, there is no net-metering HST credit because the customer is not an HST registrant, per a Canada Revenue Agency ruling.

TABLE 3 **Example of a General Service Net Metering Customer's Bill**	
Service charge: $24.57/month	$ 24.57
First block demand: 20.0 kW x $0.00	0.00
Second block demand: 18.7 kW x $13.43	251.14
First block energy: 5,000 kWh x $0.2043	1,021.50
Second block energy: 1,080 kWh x $0.1346	145.37
Subtotal	**1,442.58**
HST: $1,442.58 @ 15%	216.39
Net metering credit: 4,640 kWh x $0.2043	(947.95)
Net metering credit: 1,080 kWh x $0.1346	(145.37)
Net metering HST credit: $1,093.32 @ 15%	(164.00)
Total bill for current month	**$ 401.65**

IR-4 Presumably the Tignish Substation is now complete and 2025 brings the new Woodstock Substation to completion as described. But the roles and support of each Substation for the planned Skinners Pond wind farm are not. Perhaps more importantly the integration of the new Government owned transmission line from Sherbrooke to Skinners Pond is not included. An announcement of $43M federal government funding was made in 2020 yet still no MECL planning references are included in this 2025 Capital Application. It is understood that any Project Proponent costs would not be included in this application but it is believed that the PEI Energy Corporation and MECL have been mutually planning (hopefully) transmission and substation requirements. Please explain how this critical project is being supported by MECL.

Response:

The requirements for the Tignish and Woodstock substation projects are not based on or related to any third-party generation or transmission projects planned for PEI. Also, because the referenced wind farm and transmission line projects are external to Maritime Electric initiatives, any inquiries concerning their development should be made directly to the project proponent(s).

As with any development project that requires a grid connection, Maritime Electric communicates with the proponent to understand their requirements and all costs incurred by the Company to make system modifications are recovered from the proponent as a contribution in aid of construction (“CIAC”). In some cases, where system modifications provide direct benefit to Maritime Electric customers, the CIAC required from the proponent is adjusted accordingly.

Concerning the assumption that the Tignish substation is now complete, this is not the case. The land purchase for the substation has been delayed pending the approval of a development permit at the municipal level. Concerning the Woodstock substation, the project is on schedule for completion in late 2025.

IR-5 The new Scotchfort Substation, the Y-119 Extension to Scotchfort and the Y-109 Rebuild projects are described as being a set of interdependent projects spanning four years from 2025 to 2028 and estimated to cost nearly $40M. Following the recent approach for major projects to be extracted from annual capital requests and submitted as Supplemental Capital budgets, would MECL consider submitting this major Distribution/Transmission expansion also as “Supplemental”?

Response:

Projects such as the Scotchfort substation, the Y-119 line extension to Scotchfort, and the Y-109 line rebuild are similar to other transmission category projects included in past capital budget applications. As such, and because a separate supplemental capital budget request application would not materially change the information already included in the 2025 Capital Budget Application, the current approach is appropriate and preferred.

IR-6 Building upon the usefulness of separating "Supplemental Capital Expenditures" from "normal" annual capital expansion/maintenance expenditures, please provide a table for the ten years 2019 to 2028 to show the evolution of actual and estimated data for annual capital expenditures and annual energy delivered and compute the ratio ($ per GWh) of "Annual Capital Expenditure ($)" to "Delivered Energy (GWh)". In two separate lines on this table please include the sub-ratios of Distribution Expenditures ($), and Transmission Expenditures ($) to Delivered Energy (GWh). Recent data for comparable Canadian electricity Utilities' and their individual "Annual Capital Expenditure ($)" and "Delivered Energy (GWh)" data would be helpful "baselines". The proposal here is that the "Annual Capital Expenditure ($)" to "Delivered Energy (GWh)" ratio could be a useful Utility Key Performance Indicator (KPI).

Response:

Actual and forecast amounts for annual capital expenditures and annual energy delivered, along with the requested dollar per gigawatt-hour ("GWh") ratios is provided in Table 4.

TABLE 4
Ratio of Capital Expenditures to Delivered Energy (GWh)
Assumes "Delivered Energy" is Energy Sales (which excludes Losses and Station Service) and is not "Net Produced and Purchased"

	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Forecast[a]	2025 Forecast[b]	2026 Forecast[b]	2027 Forecast[b]	2028 Forecast
Total Capital Expenditures ($) (A)	$ 35,070,699	$ 34,544,713	$ 42,168,820	$ 47,390,605	$ 66,351.020	$ 85,249,000	$ 93,552,000	$ 103,437,000	$ 100,771,000	$ 101,125,000
Transmission Capital Expenditures ($) (B)	8,674,018	7,854,808	11,600,474	12,362,651	13,054,376	21,095,000	27,032,000	37,610,000	40,376,000	38,122,000
Distribution Capital Expenditures ($) (C)	23,777,736	23,530,797	27,473,849	30,282,427	42,057,240	62,872,000	60,407,000	51,648,000	51,382,000	53,997,000
Delivered Energy										
Energy Sales (GWh) (D)	1,286.9	1,292.7	1,326.0	1,390.7	1,479.2	1,545.1	1,606.4	1,649.1	1,682.6	1,715.9
Total Capital Expenditures per unit Delivered Energy ($/GWh) (E = A/D)	27,252	26,723	31,802	34,077	44,856	55,174	58,237	62,723	59,890	58,934
Transmission Capital Expenditures per unit Delivered Energy ($/GWh) (F = B/D)	6,740	6,076	8,748	8,890	8,825	13,653	16,828	22,806	23,996	22,217
Distribution Capital Expenditures per unit Delivered Energy ($/GWh) (G = C/D)	18,477	18,203	20,719	21,775	28,432	40,691	37,604	31,319	30,537	31,469

a. Includes annual Capital Budget Application, AMSE project and 2023 carryover amounts.
b. Includes annual Capital Budget Application and AMSE project amounts.

Concerning the request for recent similar data for comparable Canadian electric utilities, Maritime Electric does not have this information.

IR-7 Please reconcile the capital expenditure data presented in Schedule A of this application with the different capital expenditure data presented in the 2023 Sustainability Report.

Response:

Upon a review of Appendix A in the 2025 Capital Budget Application, it was determined that carryover expenditures included in the actual and forecast amounts were not all recorded in the same manner.

An amended Appendix A (provided herein as IR-7 – Attachment 1) shows the actual and forecast amounts with carryover expenditures recorded in the year they occurred.

The Annual Net Capital Expenditure totals in the amended Appendix A match the Total Annual Capital Expenditures in the 2023 Sustainability Report; however, the per-category amounts for Generation, Distribution and Transmission and Other in the 2023 Sustainability Report still do not match the amended Appendix A. The reason for this difference is that in the 2023 Sustainability Report, carryover amounts for the Generation, Distribution and Transmission infrastructure categories are included in “Other expenditures,” along with Contributions and all Corporate, GEC and IDC expenditures. In the amended Appendix A, carryover expenditures are included in the Generation, Distribution Transmission and Corporate annual amounts, and GEC, IDC and Contributions are provided as separate line items.

IR-8 The PEI Government's Oil to Heat Pump Affordability (OHPA) program is cited to be continuing the annual increasing costs for "Overhead and Underground Services". Please provide an estimate of the annual increases since the OHPA program was introduced. Has MECL requested any offset funding from the PEI Government; if not is this topic under consideration?

Response:

The PEI Government initiated the Oil to Heat Pump Affordability ("OHPA") program and expanded its Free Heat Pump ("FHP") program in early 2024. To end of September 2024, over 460 program-related service orders have been created. Maritime Electric costs associated with these service orders is approximately $369,000. These costs are only partially covered by the standard service fee of $75.08, which is currently being paid by the Department of Environment, Energy and Climate Action on behalf of FHP and OHPA qualified customers.

With respect to offset funding, Maritime Electric adds an administrative fee of ten per cent to the service fees billed to Government to cover the costs associated with consolidating program-related service fees into one monthly bill. Government has also been advised that if the volume of planning work to prepare program-related service orders results in overtime costs, such costs may need to be offset by the Government to avoid negatively impacting non-program-related services.

IR-9 In the 2024 Capital budget, the “New Generation” expenditure category forecasted a three (3) year expenditure of $139M but this allocation has now been removed from Exhibit A. It is assumed that the planned 2023 Supplemental Capital Budget application detailing “generation technology and associated costs” has now been submitted to IRAC. Please confirm the status of this Application and briefly summarize the “New Generation” strategy included to meet the PEI continuing peak load increase.

Response:

Maritime Electric’s application for new generating capacity is still being developed and expected to be filed with the Commission later this year. The application will reflect new capacity requirements included in the December 2022 Capacity Resource Study (provided herein as IR-9 – Attachment 1) and the July 2023 addendum report, Extreme Weather Event Capacity Impact (provided herein as IR-9 – Attachment 2). The application will include more information on proposed generation technology and associated cost estimates will be provided.

IR-10 As peak load demand is a significant driver of capital budgets, please provide the monthly peak loads for 2022, 2023 and 2024 as:

a. Net PEI Peak Load and,
b. MECL customers only

Response:

a. Table 5 shows the PEI monthly net peak load for January 2022 to September 2024. Values are shown in megawatts ("MW").

TABLE 5 PEI Net Monthly Peak Load (MW)			
	2022	**2023**	**2024**
Jan	322.9	303.7	342.2
Feb	300.6	395.0	328.6
Mar	295.8	276.1	339.6
Apr	250.4	270.1	259.8
May	217.2	234.4	230.4
Jun	208.5	215.2	240.8
Jul	234.6	247.4	251.2
Aug	237.9	215.6	249.2
Sep	211.7	223.8	225.7
Oct	194.5	261.3	-
Nov	277.0	301.1	-
Dec	307.2	326.6	-

b. Table 6 shows the Maritime Electric monthly net peak load for January 2022 to September 2024. Values are shown in MWs.

TABLE 6 Maritime Electric Net Monthly Peak Load (MW)			
	2022	**2023**	**2024**
Jan	292.6	275.7	321.2
Feb	273.5	359.0	298.9
Mar	268.7	250.3[a]	308.1
Apr	227.2	245.5	235.0
May	197.0	213.8	209.1
Jun	190.0	196.2	221.2
Jul	214.6	225.4	228.6
Aug	218.4	196.0	228.0
Sep	192.8	203.2	205.0
Oct	177.3	237.7	-
Nov	251.9	274.7	-
Dec	279.3	295.8	-

a. Incorrectly provided as 269.8 MW in response to Roger King IR-12 in September 2023.

IR-11 Please estimate the annual increases in Summer and Winter peak loads that can be attributed to the PEI Government's Oil to Heat Pump Affordability (OHPA) program from its inception to 2024.

Response:

This response involves a number of assumptions for a typical household that participates in the OHPA program. Table 7 shows the estimated increase in winter peak load due a typical household.

TABLE 7 Increase in Winter Peak Load due to a Typical Participant in the OHPA Program		
Description	**Value**	**Unit (or Note)**
Annual space heating requirement for a typical house (A)	85.00	gigajoules (GJ)
Conversion of GJ to Btu (B = A x 947,817)	80,571,000	Btu
Oil furnace efficiency (for reference) (C)	0.80	80 per cent
Higher heating value (HHV) of 1 litre furnace oil (for reference) (D)	36,200	Btu/litre
Conversion to litres furnace oil (for reference) (E = (B / (D x C))	2,782	litres
Annual Heating Degree Days below 12°C (F)	2,750	PEI ten-year average
Space heating requirement at -15°C (G= (12°C – (-15°C) x B) / F)	791,061	Btu/day
Conversion of MMBtu/day to Btu/hour (rounded) (H = (G) / 24))	33,000	Btu/hour
Supply of heating load at -15°C	**Btu/hour**	**kilowatt (kW)**
- One mini-split heat pump with COP of 2.5 [a] at -15°C for half of load	16,500	1.9
- Balance of load supplied with resistance heating[b]	16,500	4.8
TOTAL	**33,000**	**6.7**

a. COP of 2.5 means the coefficient of performance for the heat pump is 2.5 times as efficient as resistance heating.
b. Efficiency of resistance heating is 1 kW = 3,412 Btu/hour

Using the same mini-split heat pump to provide 12,000 Btu/hour of cooling at the summer peak will require 0.8 kW.

The Table 8 below shows the estimated increases in winter and summer peak loads due to the OHPA program. The table is based on the following assumptions:

- 4,500 households participate in the program over three years;
- Registration for the program began in late December 2023, so the first winter peak impacted by the program will be for 2024/2025; and
- 375 participants have equipment in place for the 2024 summer peak.

TABLE 8 Estimated Impact of OHPA Program on Winter and Summer Peak Loads						
Winter Peak	**Cumulative Number of Participants**	**Cumulative Increase (MW)**		**Summer Peak**	**Cumulative Number of Participants**	**Cumulative Increase (MW)**
-	-	-		2024	375	0.3
2024/2025	1,500	10.1		2025	1,875	1.5
2025/2026	3,000	20.1		2026	3,375	2.7
2026/2027	4,500	30.2		2027	4,500	3.6

IR-12 Although text references in this application no longer refer to the “Integrated System Plan”, is the 2023 updated version available to provide context to this capital application? IR–13 response last year suggested that mid 2024 was the expected release period.

Response:

An update to the 2020 Integrated System Plan (“ISP”) is in progress with an expected completion date in 2025. As the 2020 ISP considers system load levels to 375 megawatts (“MW”), it is still useful for providing context to the 2025 Capital Budget Application.

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

IR-7 – Attachment 1

Maritime Electric Company, Limited Summary of Actual and Forecast Capital Expenditures (2016 to 2029)														
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
	Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Budget**	**Budget**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
Generation (A)	1,241,112	1,064,720	1,000,667	485,340	1,425,415	1,037,146	1,678,001	6,511,909	1,430,000	1,137,000	2,749,000	2,196,000	3,507,000	2,377,000
Distribution (B)	18,246,306	19,834,463	21,445,487	23,777,736	23,530,797	27,473,849	30,282,427	42,057,240[1]	62,872,000[3]	60,407,000[8]	51,648,000[12]	51,382,000	53,997,000	56,028,000
Transmission (C)	8,283,251	10,832,373	6,989,530	8,674,018	7,854,808	11,600,474	12,362,651	13,054,376	21,095,000[4]	27,032,000	37,610,000	40,376,000	38,122,000	38,329,000
Corporate (D)	1,039,510	841,786	2,143,044	1,850,589	1,894,376	2,311,382	3,157,514	4,692,794	12,368,000[5]	10,498,000[9]	10,793,000[13]	6,958,000[15]	4,947,000	4,341,000
Subtotal (E=A+B+C+D)	28,810,179	32,573,342	31,578,728	34,787,683	34,705,396	42,422,850	47,480,592	66,316,319	97,765,000	99,074,000	102,800,000	100,912,000	100,573,000	101,075,000
GEC (F)	477,714	502,450	475,368	567,505	489.745	681,043	696,617	841,522	844,000	919,000	924,000	947,000	971,000	996,000
IDC (G)	405,915	449,760	432,111	474,433	444,170	548,015	559,997	779,035	1,219,000[6]	2,109,000[10]	2,163,000[14]	1,112,000	1,181,000	1,193,000
Subtotal (H=E+F+G)	29,693,808	33,525,552	32,486,207	35,829,621	35,639,311	43,651,908	48,737,207	67,936,876	99,828,000	102,102,000	105,887,000	102,971,000	102,725,000	103,264,000
Less: Contributions (I)	(1,262,517)	(746,454)	(677,905)	(758,922)	(1,094,598)	(1,483,088)	(1,346,601)	(1,585,856)	(14,579,000)[7]	(8,550,000)[11]	(2,450,000)	(2,200,000)	(1,600,000)	(1,450,000)
Net Capital Expenditures (J=H+I)	**$ 28,431,291**	**$ 32,779,098**	**$ 31,808,302**	**$ 35,070,699**	**$ 34,544,713**	**$ 42,168,820**	**$ 47,390,605**	**$ 66,351,020**	**$ 85,249,000**	**$ 93,552,000**	**$103,437,000**	**$100,771,000**	**$101,125,000**	**$101,814,000**

1 2023 Distribution total includes $385,628 for the Advanced Metering Infrastructure (“AMI”) component of the Advanced Metering for Sustainable Electrification (“AMSE”) project, which was not included in the 2023 Capital Budget Application.
2 2023 Corporate total includes $992,349 for the Customer Information System (“CIS”) component of the AMSE project, which was not included in the 2023 Capital Budget Application.
3 2024 Distribution total includes $17,107,000 for the AMI component of the AMSE project, and $5,324,000 for items carried over from 2023. These amounts were not included in the 2024 Capital Budget Application.
4 2024 Transmission total includes $3,582,000 for items carried over from 2023 which was not included in the 2024 Capital Budget Application.
5 2024 Corporate total includes $8,467,000 for the CIS component of the AMSE project, and $285,000 for items carried over from 2023.These amounts were not included in the 2024 Capital Budget Application.
6 2024 Interest During Construction (“IDC”) total includes $420,000 for the AMSE project, which was not included in the 2024 Capital Budget Application.
7 2024 Contributions total includes ($12,000,000) for the AMSE project and ($1,400,000) for contributions carried over from 2023. These amounts were not included in the 2024 Capital Budget Application.
8 2025 Distribution total includes $16,635,000 for the CIS component of the AMSE project, which was not included in the 2025 Capital Budget Application.
9 2025 Corporate total includes $7,495,000 for the CIS component of the AMSE project, which was not included in the 2025 Capital Budget Application.
10 2025 IDC total includes $1,240,000 for the AMSE project, which was not included in the 2025 Capital Budget Application.
11 2025 Contributions total includes ($7,000,000) for the AMSE project, which was not included in the 2025 Capital Budget Application.
12 2026 Distributions total includes $3,657,000 for the AMI component of the AMSE project.
13 2026 Corporate total includes $6,865,000 for the CIS component of the AMSE project.
14 2026 IDC total includes $1,140,000 for the AMSE project.
15 2027 Corporate total includes $2,371,000 for the CIS component of the AMSE project.

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

IR-9 – Attachment 1

Capacity Resource Study

Evaluation of Various Technology Options for Maritime Electric Company

Prepared for

Maritime Electric Company, Ltd.

Prepared by Sargent & Lundy

Report SL-017203

FINAL

December 9, 2022

Project 14782.001

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Sargent & Lundy

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ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this document has been prepared, reviewed, and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASSQC Q9001 Quality Management Systems.

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ACRONYMS AND ABBREVIATIONS

Acronym/Abbreviation	Definition/Clarification
B20, B100	20% or 100% biodiesel fuel blend
BESS	Battery energy storage system
BOP	Balance of Plant
CAD	Canadian dollars
CAES	Compressed air storage system
CO_2e	Carbon dioxide equivalent
CSP	Concentrated solar power
CT	Combustion turbine
DSM	Demand side management
ELCC	Effective load carrying capability
EPA	Energy purchase agreement
EPRI	Electric Power Research Institute
GW	Gigawatt
GWh	Gigawatt hour
IRP	Integrated resource plan
ISP	Integrated system plan
kW	Kilowatt
kWh	Kilowatt hour
Li-Ion	Lithium ion
LMP	Locational marginal price
LNG	Liquified natural gas
MECL	Maritime Electric Company, Limited
MW	Megawatt
MWh	Megawatt hour
NBEM	New Brunswick Energy Marketing
NPCC	Northeast Power Coordinating Council
PEI	Prince Edward Island
PV	Photovoltaic
RICE	Reciprocating internal combustion engines
S&L	Sargent & Lundy
SAT	Single axis tracking
SMR	Small modular reactors
TWh	Terawatt hour
USD	United States dollars
U.S. EIA	United States Energy Information Administration

EXECUTIVE SUMMARY

Sargent & Lundy (S&L) was engaged by Maritime Electric Company (Maritime Electric or MECL) in mid-2022 to develop this Capacity Resource Study for the purposes of evaluating a variety of different electricity capacity resource technologies, developing cost estimates, and recommending technologies well suited to help Maritime Electric cost-effectively achieve its most critical goals and needs.

From the perspective of this Capacity Resource Study, Maritime Electric's key goals and needs that are the focus of the resource selection process are summarized as follows:

1) **Meeting Both Energy and Capacity Obligations:** Maritime Electric must meet both a) energy obligations and b) regional capacity obligations.

   Energy obligations are those associated with Maritime Electric meeting the system's electrical load continuously throughout the day. For example, if system load (i.e., demand) is 200 MW at a certain point during the day, Maritime Electric might be able to meet this load with 70 MW generated from the on-island wind farms and 130 MW from electricity imported from the mainland. As system load and wind generation changes throughout the day and over the course of the year, the amount of electricity purchased from the mainland, or occasionally generated by on-island generators, changes with time.

   Capacity obligations are the share of reserved capacity that electric utilities must have, such that the Northeast Power Coordinating Council (NPCC) reliability standards for the Maritimes Area (which consists of Prince Edward Island [PEI], New Brunswick, Nova Scotia, and northern Maine) are met. The NPCC capacity standards are established to help maintain a stable and reliable electrical system. Load serving entities, such as Maritime Electric, are required to contribute to meeting the standards set by NPCC by having a sufficient amount of reserved capacity.

   For reference, the types of resources that Maritime Electric can utilize to meet its capacity obligations are listed below. Maritime Electric can either own these resources on-island, or Maritime Electric can purchase the capacity from power plants (or energy storage facilities) located on PEI or off-island via an agreement.

   - **Demand Response / Demand Side Programs**: Demand response programs (also known as demand side management or DSM) incentivize customers to shift/reduce electrical usage during certain times. The net result of these programs is that they help the utility better balance supply and demand. For the purposes of capacity planning, demand response is considered a dispatchable resource and can be counted towards meeting capacity obligations due to the fact that it helps utilities reduce peak demand.

- **Energy Storage**: Energy storage systems are effective sources of capacity that Maritime Electric could utilize to meet its capacity obligations. Energy storage systems are considered dispatchable resources.
- **Dispatchable Generators**: A dispatchable generator is one where the operator has control over when the unit is on/off and at what MW output level the generator is operating at. Some examples of common dispatchable generator technologies include engines and combustion turbines. Dispatchable generators are well suited to help Maritime Electric meet its regional capacity obligations.
- **Non-Dispatchable Generators**: These generators are those where the operator only has partial control over generator operation. For example, the MW output level of the wind farms on PEI are dependent on the wind speed, which can vary over the course of the day. Per industry requirements, Maritime Electric can only count a portion of a non-dispatchable generator's nameplate capacity towards meeting its regional capacity obligations (e.g., Maritime Electric is only able to count less than 25% of the total wind nameplate capacity – additional information is provided in Section 2.2.1 and Appendix C). The reason for this is that when electric utilities calculate capacity contributions, they are required to account for both the resource's intermittency and timing of when the resource generates with respect to when system load is highest. Thus, while non-dispatchable generators are well suited to help Maritime Electric meet its energy obligations (thus reducing overall carbon emissions), they are not well suited to help Maritime Electric meet its regional capacity obligations.

One of the benefits of having a higher amount of capacity installed on PEI, versus purchased from mainland power plants, is that it helps to insulate Maritime Electric's customers from a likely future regional capacity shortage in northeastern Canada as a result of increasing regional demand, the retirement of all Canadian coal power plants by 2030, and a lack of adequate regional transmission infrastructure. For reference, the following table illustrates Maritime Electric's historical and estimated future capacity obligations, including the share of capacity met with on-island and mainland resources. Since the mid-2010's, the share of Maritime Electric's on-island capacity has fallen significantly due to on-island power plant retirements and increasing system load.

Table ES-1 — Capacity Obligation and Resource Outlook

Resource	2015-2019 Average	2020	2021	2022	2023	2024
MECL's Capacity Obligation (MW)	**261**	**284**	**302**	**306**	**311**	**316**
Total MECL Capacity (MW)	**276**	**287**	**302**	**306** *(est.)*	**311** *(est.)*	**316** *(est.)*
Total On-Island Capacity (%)[1]	59.4%	51.6%	49.1%	37.0%	36.4%	35.8%
Total Off-Island Capacity, i.e., Purchased from Mainland (%)	40.6%	48.4%	50.9%	63.0%	63.6%	64.2%

Notes/Sources:

1) The above on-island capacity accounts for the appropriate conversion of nameplate capacity to effective capacity (i.e., including the effective load carrying capability of the generator, or ELCC) for non-dispatchable generators (such as the wind power plants), per industry requirements. Further discussion is provided in Section 2.2.1 and Appendix C.

2) **Improving Maritime Electric's Ability to Serve Load if PEI is Electrically Disconnected from the Mainland:** A scenario where PEI is electrically disconnected from the mainland is considered an emergency scenario, and has historical precedence (since 2004, there have been nine times when PEI was either fully or partially disconnected from the mainland). During this emergency situation, on-island resources alone would have to be used to meet load and stabilize the electrical system. If PEI is fully disconnected, Maritime Electric would currently be forced to implement rolling blackouts due to the fact that there is not enough on-island generation to meet the full electrical system load. Given that the amount of on-island capacity has fallen over the last decade due to retirements, future rolling blackouts are likely to be more severe than they have been for PEI in the past. This leaves Maritime Electric's customers exposed to significant financial and health/safety risks.

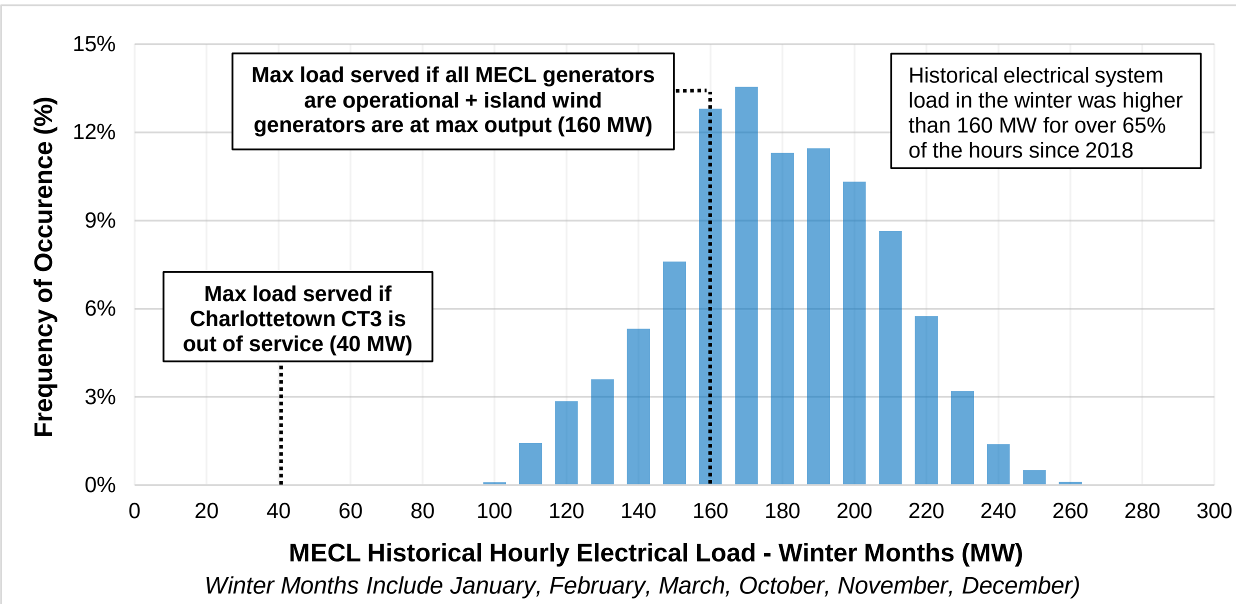
   An important point to note is that during a disconnection from the mainland, only a small portion of the on-island wind generation could be used to meet load. This is due to the fact that there is not enough dispatchable generation capacity installed on-island to be able to fully balance the generation intermittency from the large number of on-island wind generators. Without curtailment of a portion of the wind generation, there is a substantial risk of overwhelming the on-island dispatchable generators and throwing system supply and demand out of balance, which could lead to the collapse of the electrical system. At best, it is estimated that currently a maximum of 37% of all the wind generation on PEI[1] can be utilized during a full disconnection of PEI from the mainland, depending on wind conditions. This value falls to 0% in the event the largest on-island generator (Charlottetown CT3) is out of service.

[1] This is based on energy from all wind generation located on-island, which includes facilities supplying both on- and off-island customers.

The following figure shows a comparison of the historic Maritime Electric winter load to the amount of load that could be served during a disconnection of PEI from the mainland. The figure presents the distribution of historic hourly winter load (January through March and October through December) from the years 2018 through 2021. As an example, the figure illustrates that system load was approximately 190 MW for just under 12% of the hours in winter months between 2018 through 2021. During this time period, the average system load was 173 MW. Overlaid on the figure are how much load Maritime Electric will be able to serve during a disconnection of PEI from the mainland if 1) all of its dispatchable generators are available and 2) if Charlottetown CT3 is out of service. The figure illustrates that the historic system electrical load in the winter is typically far higher than the amount of electricity (in megawatts) that could be provided during a disconnection of PEI from the mainland.

Figure ES-1 — Historical System Winter Load Histogram (2018-2021)

Comparison to the Amount of Load MECL Could Serve During a Disconnection of PEI from the Mainland



For reference, both new dispatchable generators and / or energy storage could help Maritime Electric better manage situations where PEI is disconnected from the mainland. The amount that energy storage resources could help depends on a number of variables, including the charge level of the storage resource at the moment the disconnection occurs, the length of the disconnection, and whether / how much the PEI wind power plants are generating electricity during the disconnection. Due to these variables, there is significant uncertainty surrounding how beneficial energy storage resources would be during a disconnection of PEI from the mainland.

3) **Achieve Sustainability Targets:** Maritime Electric has established a greenhouse gas emissions reduction target to reduce emissions by 55% by 2030 (from 2019 levels). At present, Maritime Electric serves system load with a number of different resources; however, the majority of the energy it uses to serve load is purchased from the mainland, from New Brunswick Energy Marketing (NBEM). Energy supplied by NBEM is generated with many different resources, including renewable generators (e.g., the hydroelectric Mactaquac Generating Station) and also generators that create carbon emissions.

   A breakdown of Maritime Electric's historical generation and carbon emissions by source is provided in the following table. For reference, the energy purchased from NBEM provides a number of additional services beyond simply meeting load. Given PEI's large fleet of wind generators and the fact that wind power plants are intermittent resources, other resources that can balance the generation from the wind farms are needed. The generators that provide the balancing energy to Maritime Electric are located on the mainland and their energy is purchased through NBEM. NBEM also provides Maritime Electric additional ancillary services that help to maintain the stability of the PEI electrical system.

Table ES-2 — Historical Generation and Carbon Emissions by Source

Source	Average Historical Generation (GWh, 2019-2021)[1]	% of Total	Historical Carbon Emissions (Tonnes CO_2e)[2]	% of Total
MECL Diesel Generators	1.2[3]	0.1%	1,233	0.5%
Customer-Owned Generation (i.e., net-metered solar)	3.9	0.3%	0	0%
PEI Wind Farms	295.3	21.0%	0	0%
Point Lepreau Nuclear Generating Station	210.0	14.9%	0	0%
Purchases from NBEM	898.1	63.7%	253,389	99.5%
Total	1,408.5[3]	100.0%	254,622	100.0%

Notes/Sources:

1) Historical generation data provided by Maritime Electric.
2) Carbon emissions rates for Maritime Electric are taken from the 2022 Maritime Electric Sustainability Report (https://www.maritimeelectric.com/Media/1959/2022-sustainability-report_final_interactive-pdf_july-28-2022.pdf).
3) The average historical net generation of Maritime Electric's generators is -0.5 GWh, due to the fact that these units are primarily on standby (and to be kept on standby the generators must draw a small amount of electricity from the grid). In addition, between 2019 and 2021 the Charlottetown oil-fired generators used an average of 3.3 GWh per year while being retired from service. Shown in the above table is the generation of the diesel generators, not including the relatively small amount of electricity they used from the system. The total system generation would average 1,403.5 GWh if both the net generation from the diesel generators and the electricity used by the Charlottetown oil-fired generators was considered.

Capacity Resources Considered

Technologies in this study were ultimately selected based upon three different selection steps: a primary, secondary, and final screening. As part of this process, S&L developed cost estimates (2022 Canadian dollars) of the different technologies, considering the unique economic- / location-related specifics of PEI. Much of S&L's work is in either designing or providing project oversight through the development, construction, and operation of different generation and energy storage projects. We maintain detailed internal cost databases of project data. As a result, the cost estimates developed for this study are based on actual cost data for recent projects that are either being built or are operating.

The list of technologies initially considered for this study is provided below:

- Wind power, both onshore and offshore
- Solar power, both photovoltaic (PV) utility and rooftop scale, and concentrating solar power (CSP)
- Battery energy storage systems (BESS), lithium-ion, other storage technologies
- Reciprocating internal combustion engine (RICE), operating both on traditional and renewable fuels
- Combustion turbines (CT), aeroderivative models, operating both on traditional and renewable fuels
- Biomass power plant, operating on different types of biomass
- Nuclear power plant, small modular reactor (SMR)
- Tidal power plant or wave power plant
- Geothermal power plant
- Fuel cells

Final Resource Portfolio Selection

The final shortlisted resources are listed in the following table, along with their per kW costs and notes pertaining to their ability to help meet Maritime Electric's most critical goals/needs.

Table ES-3 — Comparison of Final Shortlisted Resources

Resource	Estimated Overnight Capital Cost ($CAD/kW)	Contributions to Energy and Capacity Obligations	Contributions When PEI is Disconnected from Mainland	Contributions to Sustainability Targets
Onshore Wind Power	$2,126 / kW	*Energy:* Excellent, but intermittent. High expected power plant capacity factor. *Capacity:* Poor, low ELCC	Unreliable resource – Can provide energy during a disconnection, but generation is intermittent. Generation intermittency/variability needs to be balanced by another resource.	Excellent – Renewable generator, very strong wind resource on PEI
Utility-Scale Solar PV	$2,389 / kW	*Energy:* Good, but intermittent. Average expected power plant capacity factor. *Capacity:* Poor, low ELCC	Unreliable resource – Can provide energy during a disconnection, but generation is intermittent. Generation intermittency/variability needs to be balanced by another resource.	Good – Renewable generator, but just average solar resource on PEI
Rooftop Solar PV	$3,131 / kW	Similar to utility-scale solar PV.	Similar to utility-scale solar PV	Similar to utility-scale solar PV
Lithium-Ion BESS	*50 MW, 1-hr* $959 / kW ($959 / kWh) *50 MW, 2-hr* $1,565 / kW ($782 / kWh) *50 MW, 4-hr* $2,670 / kW ($668 / kWh)	*Energy:* Limited – BESS can time-shift previously generated electricity. Also, there are rarely times currently or expected in the intermediate future when there is/will be excess wind + nuclear generation above system load that could be time-shifted to other hours. *Capacity:* Excellent resource for meeting capacity obligations	Uncertain / depends on event – A BESS' ability to contribute to the system (both serving load and providing renewable/load balancing) during a disconnection is dependent on the BESS state of charge when the event occurs, the length of the event, and the operation/output of the wind farms. These variables are either partially or completely out of Maritime Electric's control. At best, a BESS could significantly support the system, at worst, it would not be able to provide support.	Limited – There are rarely times currently or expected in the intermediate future when there is/will be excess wind + nuclear generation above system load that could be time-shifted to other hours. As such, BESS would not appreciably improve Maritime Electric's ability to achieve its sustainability targets. BESS' contributions will increase as more renewable generation is added to the island.
Reciprocating Engines	*Diesel* $2,257 / kW *Biodiesel* $2,556 / kW	*Energy:* Limited – RICE would likely serve as a backup generator and would be rarely utilized to meet energy obligations; however, it could generate electricity if needed. *Capacity:* Excellent resource for meeting capacity obligations	Excellent – As a dispatchable generator with quick start and ramping capabilities, RICE power plants are ideal to help Maritime Electric support the system in a disconnection scenario. Due to its operational flexibility, a RICE power plant could both serve load and provide renewable/load balancing.	Limited – Since a RICE power plant would be primarily a backup facility, the impact to total Maritime Electric emissions would be small. Also, depending on the fuel utilized (diesel vs. biodiesel), RICE could have either a small negative or small positive impact from a carbon emissions perspective.
Combustion Turbines	*Diesel* $2,486 / kW *Biodiesel* $2,643 / kW	Similar to RICE (see above)	Similar to RICE (see above)	Similar to RICE (see above)

From the final shortlisted resources, various potential portfolios were developed for consideration and final recommendation. The final portfolios considered are listed below:

- Portfolio A: BESS (lithium-ion) + onshore wind + solar PV (utility-scale and rooftop)
- Portfolio B: BESS (lithium-ion) + RICE + onshore wind + solar PV (utility-scale and rooftop)
- Portfolio C: BESS (lithium-ion) + CTs + onshore wind + solar PV (utility-scale and rooftop)
- Portfolio D: RICE/CTs + onshore wind + solar PV (utility-scale and rooftop)

Note that each of the above portfolios also assume the continued implementation and growth of the PEI DSM program. The portfolios were evaluated based on a number of criteria, including cost, Maritime Electric's most critical goals/needs, and other important considerations. As highlighted above, Maritime Electric's most critical needs are 1) meeting its energy and capacity obligations, 2) serving system load at all times, including during situations when PEI is electrically disconnected from the mainland, and 3) achieving sustainability targets.

The recommended portfolio was Portfolio D, with RICE recommended over CTs. The reasoning is as provided as follows.

The combination of RICE, onshore wind, and solar PV would provide Maritime Electric with carbon-free generation to help meet both its energy obligations and sustainability targets (via the wind and solar PV), along with capacity to meet its regional capacity obligations (via the RICE). The wind and solar PV would reduce the amount of energy needed to be purchased from NBEM. In addition, the combination of this additional energy from the wind and solar PV projects, combined with the capacity from the RICE, will help to provide a buffer against potential future regional market price volatility in energy and capacity.

Because a RICE power plant would primarily serve as a backup generator, the fact that a RICE generates carbon emissions will not substantially impact Maritime Electric's ability to meet sustainability targets, but it could create a stranded asset problem for Maritime Electric if the government of Canada begins enforcing stricter rules on allowable fuels for power generation. One distinct advantage of RICE is that it can operate on fuels the government of Canada considers to be renewable, such as biodiesel. A RICE can operate on biodiesel, with only minimal modifications required to the balance of plant equipment/storage. The lifecycle carbon emissions of biodiesel are much lower than that of traditional diesel. The fact that RICE can operate on renewable fuels helps Maritime Electric avoid the risk that a new RICE power plant would become a stranded asset in the future if fuel regulations change.

A RICE power plant would also significantly help Maritime Electric during a disconnection from the mainland. The addition of RICE to PEI would provide Maritime Electric more dependable dispatchable capacity to both serve load and also to balance the wind generation intermittency during a disconnection, which would in turn allow Maritime Electric to utilize more of PEI's wind capacity without risking an imbalance of generation and load. For reference, while a BESS project could help support the system during a disconnection from the mainland in many of the same ways, the level of support it can provide depends on the BESS' state of charge when the disconnection occurs, generation from on-island wind/solar PV, and the length of the disconnection, which are all unknowns. As a result, a BESS is not a reliable resource to support the electrical system during a disconnection of PEI from the mainland.

We estimate that a minimum of 85 MW of dispatchable capacity needs to be added to the system to be able to bring the ratio of total dispatchable capacity versus winter peak load back in line with historical levels (see Section 2.2.4 for additional discussion). Without this level of additional capacity, it is highly likely that future rolling blackouts (that might occur as a result of a disconnection of PEI from the mainland) will be much more severe than those that have occurred in the past. This capacity should be installed as soon as possible. Additional capacity beyond 85 MW will be required to replace the retirement of the Borden Generating Station generators, expected near 2030.

The following tables provide the forecasted capacity, energy, and emissions sources for Portfolio D. The new reciprocating engines in the table below are assumed to be online by 2025 and operated on biodiesel.

Table ES-4 — Estimated Portfolio D Capacity Sources

Portfolio D	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Capacity Obligation (MW):										
MECL Peak Load (Net of DSM)	284	289	293	299	305	311	317	323	329	335
Less Interruptible Load	14	14	14	14	14	14	14	14	14	14
Plus 15 % Planning Reserve	41	41	42	43	44	45	45	46	47	48
Total MECL Capacity Obligation (MW)	**311**	**316**	**321**	**328**	**335**	**342**	**348**	**355**	**362**	**369**
A) MECL Capacity Resources (MW):										
Borden Generating Station (CTs)	40	40	40	40	40	40	40	0	0	0
Charlottetown CT3	49	49	49	49	49	49	49	49	49	49
Point Lepreau Nuclear	29	29	29	29	29	29	29	29	29	29
Short Term Capacity Purchases (NBEM)	172	174	94	97	104	111	118	125	132	139
New Reciprocating Engines (Biodiesel)	0	0	85	85	85	85	85	125	125	125
Subtotal (MW)	*290*	*292*	*297*	*300*	*307*	*314*	*321*	*328*	*335*	*342*
B) Wind Power (MW):										
MECL Purchasd Nameplate Capacity	92	122	122	162	162	162	162	162	162	162
ELCC as % of Purchased	23%	20%	20%	17%	17%	17%	17%	17%	17%	17%
ELCC (MW)	*21*	*24*	*24*	*28*	*28*	*28*	*28*	*28*	*28*	*28*
C) Solar PV Power (MW):										
Rooftop Solar	15	15	15	15	15	15	15	15	15	15
Utility Scale	0	0	20	30	40	50	60	60	60	60
ELCC as % of Purchased	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
ELCC (MW)	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Total MECL Capacity (A+B+C) (MW)	**311**	**316**	**321**	**328**	**335**	**342**	**348**	**355**	**362**	**369**

Table ES-5 — Estimated Portfolio D Energy Sources

Portfolio D	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Energy Obligation (GWh)	**1,495**	**1,517**	**1,538**	**1,561**	**1,588**	**1,615**	**1,642**	**1,668**	**1,694**	**1,722**
MECL Energy Supply (GWh):										
Borden Generating Station (CTs)	1.1	1.1	0.6	0.6	0.6	0.6	0.6	0	0	0
Charlottetown CT3	1.4	1.4	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Point Lepreau Nuclear	210	210	210	210	210	210	210	210	210	210
Energy Purchases (NBEM)	968	879	865	719	729	738	747	774	800	827
New Reciprocating Engines (Biodiesel)	0	0	1.2	1.2	1.2	1.2	1.2	1.8	1.8	1.8
Wind Power	295	406	406	557	557	557	557	557	557	557
Rooftop Solar PV	20	20	20	20	20	20	20	20	20	20
Utility Scale Solar PV	0	0	35	52	70	87	105	105	105	105
Total Energy (GWh)	**1,495**	**1,517**	**1,538**	**1,561**	**1,588**	**1,615**	**1,642**	**1,668**	**1,694**	**1,722**

Table ES-6 — Estimated Portfolio D Emissions Sources

Portfolio D	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Emissions (kilo-Tonnes CO_2e)										
Borden Generating Station (CTs)	1.2	1.2	0.6	0.6	0.6	0.6	0.6	0	0	0
Charlottetown CT3	1.4	1.4	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Point Lepreau Nuclear	0	0	0	0	0	0	0	0	0	0
Energy Purchases (NBEM)	273	248	244	203	206	208	211	218	226	233
New Reciprocating Engines (Biodiesel)	0	0	0.4	0.4	0.4	0.4	0.4	0.6	0.6	0.6
Wind Power	0	0	0	0	0	0	0	0	0	0
Rooftop Solar PV	0	0	0	0	0	0	0	0	0	0
Utility Scale Solar PV	0	0	0	0	0	0	0	0	0	0
Total Emissions (kilo-Tonnes CO_2e)	**276**	**251**	**246**	**205**	**207**	**210**	**213**	**220**	**227**	**235**

Notes

1) Carbon emissions rates related to purchases from NBEM are based on 2019, 2020, and 2021 data compiled by Maritime Electric and contained in the 2022 Maritime Electric Sustainability Report (https://www.maritimeelectric.com/Media/1959/2022-sustainability-report_final_interactive-pdf_july-28-2022.pdf). Note the NBEM emissions rate (on a tonnes CO_2e per GWh basis) used to calculate carbon emissions is kept consistent for all the years shown in the table above; however, this rate is expected to fall with time as mainland utilities pursue various decarbonization strategies.
2) Biodiesel emissions assume B100 fuel is used and are calculated assuming the lifecycle emissions (from the production of the B100 fuel through combustion) are 70% less than traditional diesel fuel. The actual lifecycle emissions may vary based on a number of factors, including fuel composition, production method, etc. Note that the Canadian government considers biodiesel as a renewable fuel.

The reason BESS was not included in the recommended portfolio was primarily because of two reasons. First, a BESS solution is not as effective as the other shortlisted technologies at helping Maritime Electric meet its most critical needs. For reference, Maritime Electric's most critical needs are defined as 1) meeting its energy and capacity obligations, 2) serving system load at all times, including during situations when PEI is electrically disconnected from the mainland, and 3) achieving sustainability targets. Additionally, a BESS solution is a higher cost option than the other shortlisted technologies.

It is important to note that a BESS solution could offer some additional advantages for Maritime Electric beyond its most critical needs, such as allowing Maritime Electric to pursue an energy arbitrage strategy (if they wished to participate in an energy marketplace in the future), providing various ancillary services and other system electrical support, and helping to manage times when there is excess wind generation (which does not occur frequently today, but will occur more frequently in the future as more onshore wind is integrated onto PEI). If it were determined that a BESS solution should be pursued, we recommend Maritime Electric pursue, potentially in coordination with interested PEI stakeholders, development of a demonstration 4-hour BESS project. As a demonstration project, Maritime Electric and PEI would be better able to assess which functions/use cases future BESS projects might be utilized for to maximize the benefit for PEI and Maritime Electric's customers.

1. INTRODUCTION

Sargent & Lundy (S&L) was engaged by Maritime Electric (or MECL) in mid-2022 to develop this capacity resource study for the purposes of evaluating a variety of different capacity resource technologies, developing detailed cost estimates, and recommending the technologies best suited to helping Maritime Electric achieve its most critical goals/needs.

At a high level, this report was developed through detailed reviews and analysis of Maritime Electric's planning documents, reviews of planning documents/information from the other major utilities and planning organizations in the Maritimes region, our experience with and understanding of the technical characteristics of the different capacity resources, and our experience preparing detailed cost estimates for various capacity resource technologies.

This report is structured as follows:

- **Resource Planning Considerations** – This section of the report highlights the key planning considerations that factor prominently in the analysis of the different capacity resource options considered and ultimately drive the final resource recommendations.
- **Carbon Emissions Planning** – This section augments the previous section with a specific focus on how Maritime Electric can most effectively achieve its carbon reduction/sustainability targets. This section discusses some of the challenges associated with portfolio decarbonization, along with potential ways those challenges can be addressed.
- **Capacity Resource Comparison** – This section of the report introduces the different capacity resources considered as part of this analysis. For each resource, a summary of the resource's key technical characteristics and applicability to Prince Edward Island (PEI) / Maritime Electric's portfolio are discussed.
- **Capacity Resource Analysis** – In this section, both a preliminary and secondary screening of the different resources is performed to narrow the technologies down to those that are best suited to meeting Maritime Electric's most immediate needs/goals.
- **Capacity Resource Recommendations** – The final section of this report compares various portfolios that combine the different short-listed technologies, ultimately recommending a final portfolio.

This report is meant not only to provide a recommendation of a portfolio of technologies for Maritime Electric, but also to serve as a guide to the reader on the unique considerations that drive the final resource recommendations. In addition to the main sections of the report, a number of appendices are also included that provide supporting information.

The following subsection provides a brief introduction to S&L.

1.1. SARGENT & LUNDY INTRODUCTION

S&L is one of the oldest and most experienced full-service architect-engineering firms in the world. Founded in 1891, the firm is a global leader in power and energy with expertise in: all forms of electric power generation; resource planning; power transmission and distribution; grid modernization; energy storage; fuel infrastructure; energy consulting; decarbonization; hydrogen; carbon capture; oil and gas infrastructure; and physical and cyber-security. S&L's power generation experience includes wind, solar, natural gas- and diesel-fired, nuclear power, coal-fired; biomass-fired, oil-fired power plants, among others. We are frequently asked to perform analyses, much like this one for Maritime Electric, to help utilities plan for the future, focusing on the best ways to cost-effectively achieve decarbonization goals, improve system reliability, and maximize value for customers and stakeholders.

From the perspective of generation and energy storage cost and performance estimates, S&L is one of the most recognized firms in the energy industry. Our work frequently consists of either designing or providing project oversight through the development / operation of generation and energy storage projects. S&L maintains detailed cost databases of these projects, which helps inform our cost estimates such that they are based on actual cost data for recent projects that are either being built or are operating. Due to our knowledge of generation and energy storage costs, we helped develop the U.S. Energy Information Administration's (EIA) cost and performance benchmarking database, which consists of 25 different power generation and energy storage technology cases. In addition, we have been performing similar scopes of work for numerous other utilities and for the Electric Power Research Institute (EPRI) for many years.

More information about S&L can be found on our website, at sargentlundy.com.

2. RESOURCE PLANNING CONSIDERATIONS

This section details the key planning considerations that guide the analysis of the different capacity resource technologies evaluated later in the report. Important background information on the various considerations is provided as necessary.

2.1. MARITIME ELECTRIC'S ENERGY AND CAPACITY OBLIGATIONS

Maritime Electric must not only meet the hourly electricity demand for their customers, but it must also have a sufficient amount of generation capacity (either owned by Maritime Electric or purchased from resources on PEI or on the mainland) to meet regional reliability requirements of the electrical system. The two requirements are discussed further below:

2.1.1. Energy Obligations

Energy obligations are those that are associated with real-time system electrical demand. Maritime Electric's energy obligations vary on a continuous basis throughout the day, based on customer electricity usage. Maritime Electric has historically served this load with energy generated by three different sources:

1. A total of 29 MW of continuous baseload energy purchased from the Point Lepreau Nuclear Generating Station (located on the mainland in New Brunswick);
2. Energy purchased from wind farms located on PEI. Generation from the wind farms varies hourly based on wind speed;
3. Energy purchased from the mainland through an energy purchase agreement (EPA) with New Brunswick Energy Marketing (NBEM). The amount of energy purchased from NBEM varies continuously depending on the system load and real-time electricity generation from PEI's wind farms;

These three resources have historically combined to meet over 99% of Maritime Electric's load (with the remainder supplied by Maritime Electric's on-island backup generation). In addition, these resources are mostly carbon-free. In fact, 86% of the energy that Maritime Electric provides to its customers (as of 2021) is generated with resources that do not emit carbon[2].

Maritime Electric's system load, both in terms of system peak and energy, has increased virtually every year since 2010. The following table illustrates both historical and forecasted load. For reference, there has been over a 25% load increase (in GWh) between 2010 and 2021.

[2]Taken from page 23 of the 2022 Maritime Electric Sustainability Report (https://www.maritimeelectric.com/Media/1959/2022-sustainability-report_final_interactive-pdf_july-28-2022.pdf)

Table 2-1 — Historical and Forecasted Annual Energy and Peak Load

Year	2015-2019 *(avg.)*	2020	2021	2022 *(est.)*	2023 *(est.)*	2024 *(est.)*
MECL Energy (GWh)	1,318	1,392	1,433	1,477	1,495	1,517
December Peak Load (MW)	239	257	276	280	284	289

The increasing load correlates with the steady population growth PEI has seen over the most recent decades. In 2011, the PEI Statistics Bureau reported that PEI had just over 140 thousand residents[3], which grew to 154 thousand residents by 2021[4]. This corresponds to a 10% growth in island population between 2011 and 2021. Maritime Electric has also noted a continuous shifting towards electric heating on the island, which is expected to continue moving forward over the near to intermediate term. This shift helps to explain the fact that electricity consumption growth on the island has outpaced population growth on the island over the most recent decade.

Moving forward, we would expect system load to continue to increase due to a combination of continued population growth (which is forecasted to increase steadily moving forward based on estimates by the PEI Statistics Bureau), a continued transition of island residents to electric heating, and some adoption of electric vehicles. There are some considerations that will help to offset system load growth, including increasing demand side resources / policies, energy efficiency improvements, increasing resident-owned generation such as solar panels on homes (which provides energy but does not reduce peak system load), etc. However, based on our review of the current / forecasted impact of the demand side management (DSM) program, we do not expect the DSM program will be able to fully offset the expected increase in load as a result of the island population growth and the continued transition of residents to electric heating.

2.1.2. Capacity Obligations

Capacity obligations are associated with ensuring there is enough generation capacity installed in the region to maintain system resource adequacy[5]. The capacity requirements for the entire Maritimes Area, which includes PEI, New Brunswick, Nova Scotia, and northern Maine, are established by the Northeast Power Coordinating Council (NPCC).

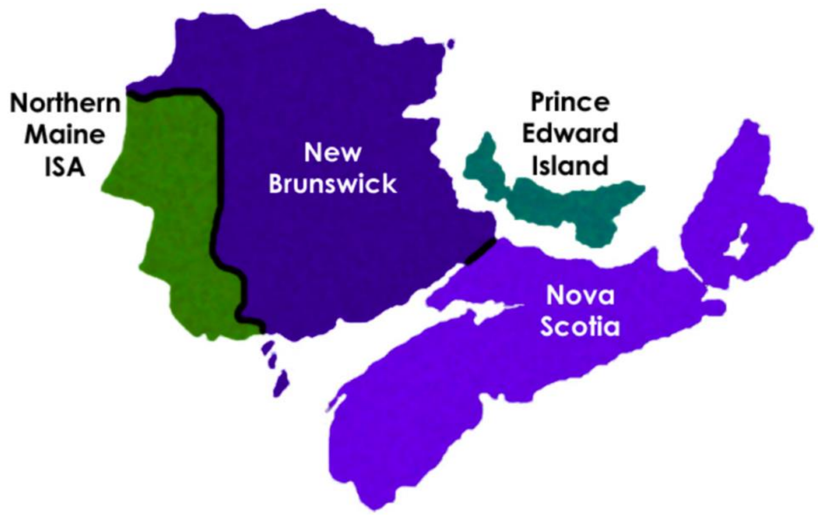
As one of the utilities serving electrical load in the Maritimes Area, Maritime Electric coordinates with the other utilities in the Maritimes Area to ensure the regional capacity requirements established by NPCC are

[3] http://www.gov.pe.ca/photos/original/2011Census.pdf
[4] https://www.princeedwardisland.ca/sites/default/files/publications/2021_census_reports.pdf
[5] Resource adequacy refers specifically to the provision that the region has a sufficient number of generating resources installed to meet both system load and generating reserve requirements. The amount of generation installed in the region needs to be high enough to cover for the periodic maintenance of generators and the probability that some generators will be out of service due to forced outages (i.e., broken down)

met. Under the terms of its Interconnection Agreement with New Brunswick Power, Maritime Electric is required to be able to carry sufficient generating capacity to meet its firm peak hourly load, plus a 15% planning reserve margin. Additionally, a single capacity resource cannot account for more than 30% of Maritime Electric's capacity contributions.[6]

The following figure illustrates the Maritimes Area.

Figure 2-1 — Maritimes Area Region for Capacity Planning[7]



It is important to note the distinct differences between Maritime Electric's energy and capacity requirements. While related, energy and capacity are also distinctly different. Resources that Maritime Electric uses to meet their regional capacity obligations do not have to be the same resources that they use to meet energy obligations. For example, Maritime Electric's diesel and oil-fired generators typically account for less than 1% of annual energy generation, but they have accounted for over 40% of the capacity Maritime Electric counts toward their regional capacity sharing obligations. If Maritime Electric cannot meet its capacity obligations fully using on-island resources, it must meet them by purchasing capacity from generators elsewhere (i.e., the mainland). In 2021, Maritime Electric purchased approximately 50% of its required capacity from power plants in New Brunswick (this includes purchases from Point Lepreau). The following table compares the resources that Maritime Electric used to meet their energy and capacity obligations in 2021.

[6] These are contractual requirements per the 1977 interconnection agreement between Maritime Electric and New Brunswick Power that were established to regulate the amount that Maritime Electric / PEI contribute to the overall Maritimes Area regional capacity requirements

[7] Source: *NPCC 2021 Maritimes Area Interim Review of Resource Adequacy*

Table 2-2 — Comparison of MECL Energy and Capacity Obligations for 2021

Obligation / Resource	Energy Obligations (i.e., Load MECL Must Serve)		Capacity Obligations (i.e., to Meet Requirements Established by NPCC)	
	Energy (GWh)	% of Total	Capacity (MW)	% of Total
MECL's Obligation	1,433	-	302	-
Maritime Electric Diesel Generators	2.2	0.15%	127[1]	42%
PEI Wind Farms	280.6	19.6%	21[2]	7%
PEI Solar	5.7	0.40%	0[2]	0%
Point Lepreau Nuclear Generating Station	197.7	13.8%	29	10%
Purchases from NBEM / New Brunswick	946.8	66.1%	125	41%

Notes/Sources:

1) Due to the retirement of the Charlottetown oil-fired generators, this value falls from 127 MW to 89 MW in 2022, resulting in capacity purchases from New Brunswick increasing from 41% to 54% of the total resources Maritime Electric utilizes to meet capacity obligations.
2) The capacity values of the wind and solar generators account for the appropriate conversion of nameplate capacity to effective capacity (i.e., including the effective load carrying capability of the generator, or ELCC), which is a required conversion Maritime Electric must perform. Further discussion is provided in Section 2.2.1 and Appendix C.

In the table above, it is important to note the small amount of capacity that Maritime Electric is able to count from the PEI wind farms and solar installations towards their regional capacity obligations (21 MW and 0 MW, respectively), especially considering there are 92.5 MW of wind generation contracted with Maritime Electric. The reason for this is because the capacity contributions of these resources is calculated using a methodology that appropriately reduces their capacity value to account for both the resource's intermittency and when the resource generates with respect to when system load is highest. This calculation methodology is an industry requirement that Maritime Electric must follow. This concept/methodology is discussed in additional detail in Appendix C.

2.1.2.1. Meeting Capacity Obligations in the Future

The recent retirement of Maritime Electric's Charlottetown oil-fired generators has resulted in a significant drop in generation capacity located on PEI. As a result, in order for Maritime Electric to meet its regional capacity obligations, it has had to purchase additional capacity from New Brunswick to replace the retired capacity of the Charlottetown generators. Table 2-3 provides Maritime Electric's historical and forecasted capacity obligations, in addition to the resources that Maritime Electric has/will use to meet those obligations. It is important to note that the capacity obligations increase each year as a result of increasing island peak hourly load (Maritime Electric's load and peak load forecast is discussed further in Section 2.1.1). For reference, the capacity obligations also account for the forecasted increasing contributions from the DSM program on PEI. As can be observed in the table, the share of Maritime Electric's capacity obligations that it can meet with on-island generators falls from near 60% (between 2015 and 2019) to just above 35% following the retirement of the Charlottetown generators and the continued increase in system peak load.

Table 2-3 — Capacity Obligation and Resource Outlook

Resource	2015-2019 Average	2020	2021	2022	2023	2024
MECL's Capacity Obligation (MW)	**261**	**284**	**302**	**306**	**311**	**316**
MECL Diesel / Oil Generators[1]	143	127	127	89	89	89
PEI Wind Farms[2]	21	21	21	24	24	24
Point Lepreau Nuclear	29	29	29	29	29	29
Purchases from New Brunswick	83	110	125	164 (est.)	169 (est.)	174 (est.)
Total (MW)	**276**	**287**	**302**	**306** (est.)	**311** (est.)	**316** (est.)
Total On-Island (%)	59.4%	51.6%	49.1%	37.0%	36.4%	35.8%
Total Off-Island (%)	40.6%	48.4%	50.9%	63.0%	63.6%	64.2%

Notes:

1) The reductions from 143 MW to 127 MW in 2020 and from 127 MW to 89 MW in 2022 is a result of the retirement of the Charlottetown oil-fired generators.
2) The capacity values of the wind generators account for the appropriate conversion of nameplate capacity to effective capacity (i.e., ELCC), which is a required conversion Maritime Electric must perform. Further discussion is provided in Section 2.2.1 and Appendix C. The effective capacity of the solar generators is 0 MW; thus, they are not included in the above table.

Purchasing higher amounts of capacity from New Brunswick, or other locations, results in increased capacity market price exposure for Maritime Electric. In the event that the price of generation capacity rises, Maritime Electric's customers will be more negatively impacted by the price increase. As discussed in Section 2.4.1, the mandated retirement of coal power plants throughout Canada by 2030 will result in less available capacity in the region. With less available capacity in the region (combined with the other factors discussed in Section 2.4), we expect that the market price for capacity will rise in the future.

In addition, less on-island generation capacity translates to a higher risk for Maritime Electric's customers in the event that PEI is electrically disconnected from the mainland. During a disconnection, Maritime Electric can only serve load with the generators installed on-island. In addition, only a portion of the on-island wind generation can be used during a disconnection from the mainland due to the fact that there are not enough other on-island generators available to fully balance the wind generation (without proper balancing of the wind generation, the electrical system can collapse). As a result, any disconnection from the mainland will result in Maritime Electric not having enough generation to fully meet load and it will be forced to shed load (i.e., not fully serve all customer demand) and implement rolling blackouts. The severity of the rolling blackouts will increase with lower amounts of generation capacity installed on the island. For Maritime Electric, this risk is of significant concern given that the potential consequences of Maritime Electric not being able to serve customer load during a serious weather event are potentially catastrophic. This scenario is discussed in further detail in Section 2.2.

2.1.2.2. Potential Capacity Resources

There are many different types of technologies that provide capacity to an electrical system. In general, the technologies best suited to providing capacity to the system are those that are dispatchable, meaning the system operator has complete control over when the technology provides electricity to the system. A further discussion of the different sources of capacity that Maritime Electric could integrate and their effectiveness at helping meet Maritime Electric's regional capacity obligations are summarized below:

- **Demand Response / Demand Side Programs**: Demand response programs (DSM) incentivize customers to shift/reduce electrical usage during critical times. The net result of these programs is that they help the utility better balance supply and demand. Demand response is considered a dispatchable resource and can be counted towards meeting capacity obligations due to the fact that it helps utilities reduce peak demand.
- **Energy Storage**: Energy storage systems are a good source of capacity that Maritime Electric could utilize to meet its obligations. Energy storage systems are considered dispatchable resources. It would need to be formally quantified how much of the energy storage nameplate capacity Maritime Electric would be able to count towards its capacity obligations; however, we expect this value to be near the storage project's nameplate capacity.
- **Dispatchable Generators**: A dispatchable generator is one where the operator has control over when the unit is on/off and at what MW output level the generator is operating at. Some examples of common dispatchable generator technologies include engines and combustion turbines. Dispatchable generators are well suited to help Maritime Electric meet its regional capacity obligations.
- **Non-Dispatchable Generators**: These generators are those where the operator only has partial control over generator operation. For example, the MW output level of the wind farms on PEI are dependent on the wind speed, which can vary over the course of the day. Per industry requirements, Maritime Electric can only count a small portion of a non-dispatchable generator's nameplate capacity towards meeting its regional capacity obligations (e.g., Maritime Electric is only able to count less than 25% of the total wind nameplate capacity – additional information is provided in Section 2.2.1 and Appendix C); thus, while non-dispatchable generators are well suited to help Maritime Electric meet its energy obligations, they are not well suited to help Maritime Electric meet its regional capacity obligations.

2.2. DISCONNECTION FROM MAINLAND

An important planning consideration for Maritime Electric is a situation where PEI is electrically disconnected from the mainland. A disconnection from the mainland has the potential to have serious consequences for PEI, especially if the outage were to take place during an extreme weather event. Since PEI has seen a significant transition towards electric heating in homes, a disconnection and subsequent loss of power during extreme cold would leave many residents without heat, which could result in significant property damage (i.e., from frozen plumbing) or even loss of life. For reference, the extended power outages during winter 2021 in Texas, resulted in 246 deaths[8] and nearly $200 billion dollars (USD) in property damage[9]. While the cause of the devastation in Texas was weather-driven, it was also a consequence of lack of system preparedness for a low probability, but high severity event.

In the event that PEI is electrically disconnected from the mainland in the winter, there is not enough on-island generation installed to meet system load, which would result in Maritime Electric having to implement rolling blackouts.[10] The reason for this is twofold. First, the total capacity of Maritime Electric's on-island dispatchable generators has recently fallen due to the retirement of the Charlottetown oil-fired generators. Historically, Maritime Electric's dispatchable capacity (127 MW) has been approximately 50% of peak load; however, this number (89 MW) is now only just above 30% of peak load. Second, only a fraction of the island's wind capacity can be utilized in a scenario where PEI is disconnected from the mainland, as is discussed in the following paragraph. Table 2-7 in Section 2.2.4 provides an annual comparison of the amount of dispatchable capacity Maritime Electric has available versus system peak load.

2.2.1. Wind Capacity During Disconnection of PEI from Mainland

Both when PEI is connected to the mainland and in a scenario where it is disconnected, properly managing island load and the variable generation of the wind farms on PEI is critical, due to the fact that an imbalance of electricity supply and demand can result in a system collapse. When connected to the mainland, the load/wind balancing requirements of the PEI electrical system are provided by mainland generators and purchased through the agreement with NBEM. An example illustrating the load/wind balancing support the NBEM energy provides is shown in Figure 2-2, which illustrates a typical winter day for Maritime Electric. As can be seen in the figure, nuclear generation is fixed for each hour of the day, but the wind generation varies based on the wind speed. The NBEM energy purchases vary throughout the day and make up the difference between the system load and the wind plus nuclear energy.

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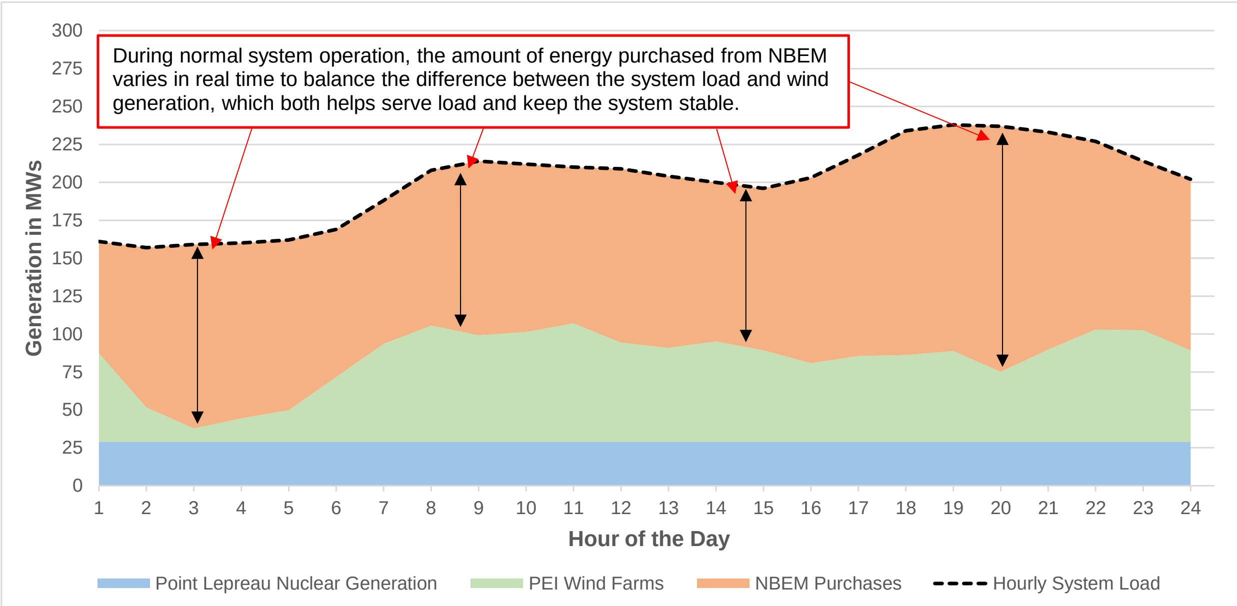
[8] https://www.texastribune.org/2022/01/02/texas-winter-storm-final-death-toll-246/amp/
[9] https://www.austintexas.gov/sites/default/files/files/HSEM/2021-Winter-Storm-Uri-AAR-Findings-Report.pdf
[10] Maritime Electric 2020 Integrated System Plan, page 41 and 42

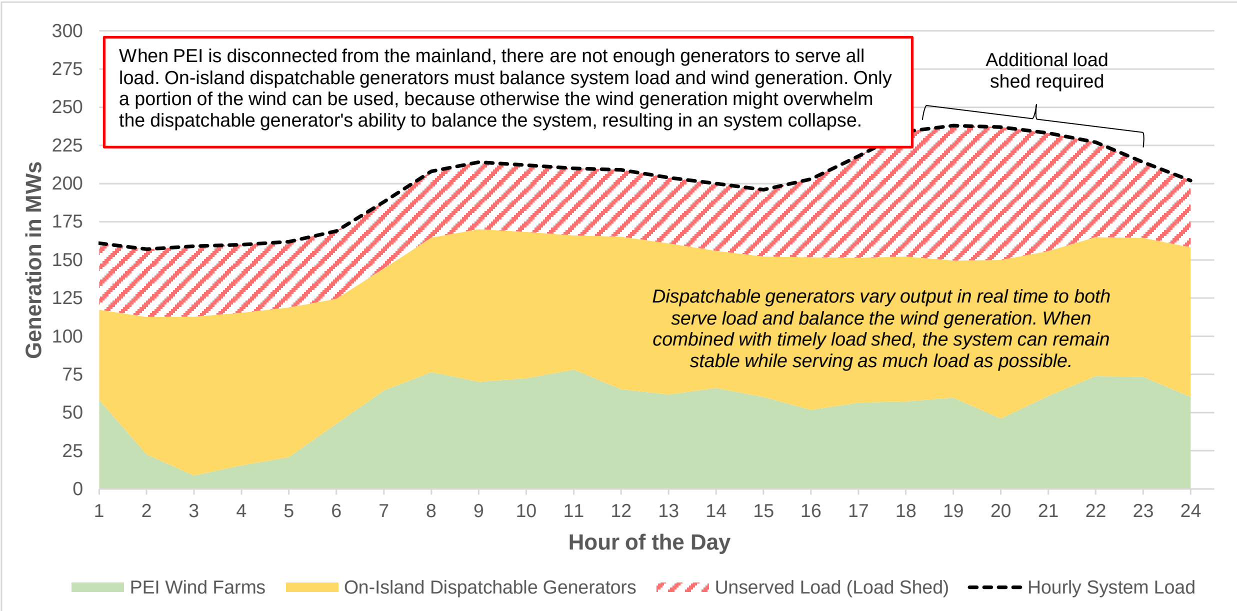
Figure 2-2 — Typical Winter Day System Dispatch



If PEI were disconnected from the mainland, these balancing requirements would need to be met by on-island generators. To balance the wind generation and system load, the dispatchable generators on PEI would need to vary output on a continuous basis to offset the peaks and valleys of the wind generation and load. Given there is a significant amount of wind capacity installed on PEI relative to the amount of on-island dispatchable capacity, only a fraction of the wind generation could be utilized when PEI is disconnected from the mainland without risking overwhelming the capabilities of the dispatchable generators on the island, leading to an electricity supply/demand imbalance and subsequent potential PEI electrical system collapse.

The following figure provides an example illustration of system dispatch in the event of a disconnection from the mainland. It is important to note that the balance between the amount of load that can be served and the amount of load that must be shed is critical during this event. To maintain this balance, Maritime Electric has to not only properly balance out the generation from the wind, but also intentionally cut power to customers on a rolling basis to not overwhelm the on-island generator's capabilities (see Section 2.2.2 for additional details on rolling blackouts).

Figure 2-3 — Winter Day System Dispatch When PEI is Disconnected



It is also important to note that during very high wind speeds (for example, during a major storm), the wind turbines must be stopped to avoid damage. In this event, much more load shed can be expected.

Maritime Electric estimates that a maximum of roughly 37% (71 MW) of all the total installed island wind nameplate capacity on PEI[11] could be dispatched if PEI were disconnected from the mainland without risking overwhelming the balancing capabilities of the dispatchable generators. Actual wind dispatch would depend on wind conditions, wind farm ability to respond to system operator directives, and contractual arrangements. In the event that the Charlottetown CT3 was also lost, the island would have an extreme shortfall in dispatchable generation that could be used for energy balancing; thus, an estimated 0% of the on-island wind generation could be utilized without risking system collapse. To illustrate this important concept, the following table was developed based on input from Maritime Electric. In the table, three different scenarios are illustrated:

- **Scenario A**: Wind generation on PEI is available and generating electricity continuously. In this scenario, the amount of wind shown in the table is the estimated maximum amount that the on-island dispatchable generators can handle without jeopardizing system stability.
- **Scenario B**: This scenario assumes that the Charlottetown CT3 is in outage. This scenario is shown to illustrate the importance of the wind balancing contributions of the on-island dispatchable resources. The loss of CT3 during an event where PEI is disconnected from the mainland would result in a significant reduction in the amount of dispatchable capacity that could be used to balance

[11] This is based on energy from all wind generation located on-island, which includes facilities supplying both on- and off-island customers.

the intermittent generation from the wind. As a result, Maritime Electric estimates that no wind generation could be utilized without risking the destabilization and potential failure of the electrical system. Load shed is expected to be much higher than Scenario A in this scenario.

- **Scenario C**: In this scenario, the wind generation is not available, due to the wind not blowing, wind speeds that are too high for operation of the wind turbines, transmission failure, or other similar reason. Load shed is expected to be much higher than Scenario A in this scenario.

The amount of load that the system can meet in all three scenarios is much lower than the peak winter load (approximately 280 MW), indicating that rolling blackouts will likely occur if PEI is disconnected from the mainland. It is important to note that the dispatchable capacity in the summer would be lower than what is shown in the table due to temperature deratings of the dispatchable generators (the estimated total capacity available in Scenario A would reduce from 160 MW to approximately 140 MW).

Table 2-4 — Capacity Available to Serve Load When PEI is Disconnected

Peak system load in the winter is approximately 280 MW

Generating Resource	Winter Nameplate Capacity (MW)	Scenario A: Wind Generation Available (MW)	Scenario B: CT3 in Outage (MW)	Scenario C: No Wind Generation (MW)
Charlottetown CT3	49	49	Unavailable	49
Borden CT1	15	15	15	15
Borden CT2	25	25	25	25
PEI Wind Farms	191	Up to 71	0	Unavailable
Total Capacity	**280**	**Up to 160**	**40**	**89**

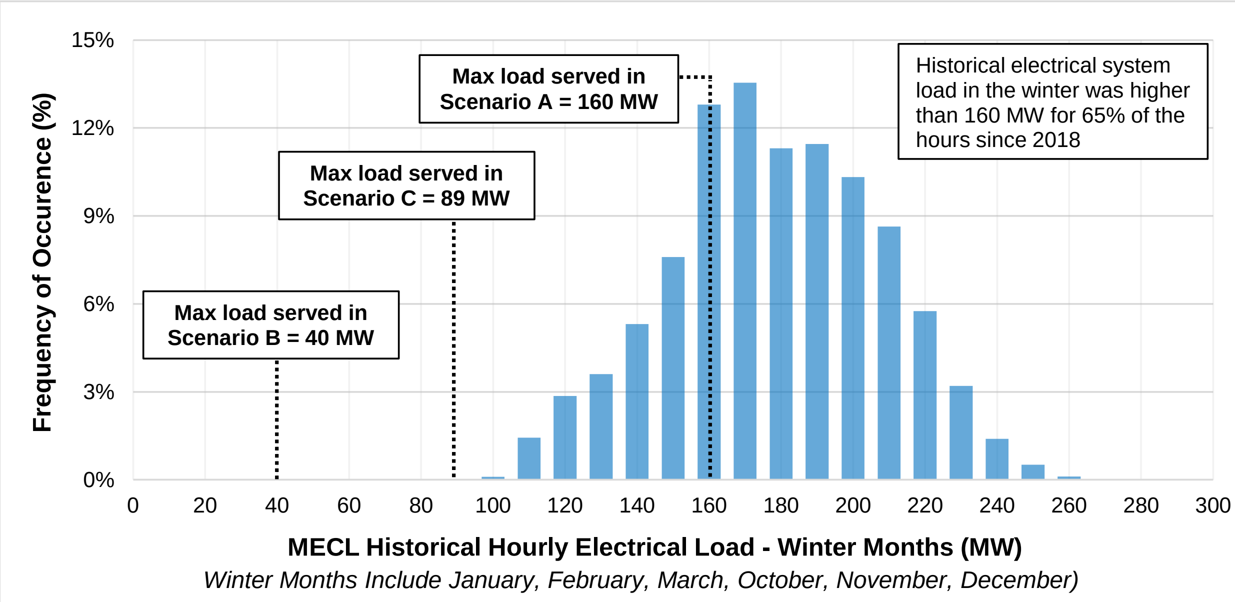
Notes:

1) The values in the above table are an estimation based on our review of the system and our discussions with Maritime Electric. Further detailed study is required to more accurately determine the amount of electricity that can be supplied, both in the current system and in the system after this report's recommendations are incorporated.

The following figure is included to illustrate how the above generation levels compare to historical system electrical demand (load) in the winter months (January through March and October through December). The figure presents the distribution of hourly electrical load based on historical data from the years 2018 through 2021. As an example, the figure illustrates that system load was approximately 190 MW for just under 12% of the hours in winter months between 2018 through 2021. During this time period, the average system load was 173 MW. Overlaid on the figure are the three different generation levels from Scenario A, B, and C in the table above. The figure illustrates the historic system electrical load far exceeded the amount of megawatts that could have been served in Scenarios A, B, and C during a disconnection of PEI from the mainland. Even the generation level of Scenario A, which is the highest of the three scenarios, generally falls short of historical hourly electrical demand.

Figure 2-4 — Historical System Winter Load Histogram (2018-2021)

Comparison to the Amount of Load MECL Could Serve During a Disconnection of PEI from the Mainland



2.2.2. Rolling Blackouts

In the event that PEI is electrically disconnected from the mainland, Maritime Electric would likely be forced to implement rolling blackouts due to the fact that there will not be enough generation to meet the full electrical system load. In a rolling blackout, different parts of the electrical grid are energized on a rotating basis, while others are without power. A rolling blackout reduces total system load such that served electrical demand does not exceed supply (a mismatch could lead to system collapse). In addition, the burden of the generation shortfall is shared such that no one area of the grid is without power for more than a set length of time.

The following table illustrates an example of how a rotating blackout might work. In this example, total system generation is assumed to equal 75 MW for each hour. The example also assumes that Areas A, B, C, and D make up an electrical system, with each area having a load of 25 MW. Since the total combined load of Areas A, B, C, and D is equal to 100 MW (4 x 25 MW), but generation is only equal to 75 MW, only three areas can be served at one time. The area without electricity is rotated each hour.

Table 2-5 — Example Rotating Blackout Schedule

Resource	Areas with Electricity	Area without Electricity
Hour 1	Areas A, B, C	Area D
Hour 2	Areas B, C, D	Area A
Hour 3	Areas A, C, D	Area B
Hour 4	Areas A, B, D	Area C
Hour 5	Areas A, B, C	Area D
Hour 6	Areas B, C, D	Area A

It is important to note that rolling blackouts become more severe if there is less generation available to dispatch. During a rolling blackout, this would translate to longer time periods where areas of the grid would have to go without power, which is a significant risk to customer safety. With the recent retirement of the Charlottetown oil-fired generators, Maritime Electric has less on-island dispatchable generation that it can dispatch during a rolling blackout. In addition, several of the island's dispatchable generators are approaching end of life and will have to be considered for retirement in the near future; for example, Maritime Electric's two Borden combustion turbines are 50 years old and some of the Summerside reciprocating engines are over 60 years old.

2.2.3. Historical Frequency of Mainland Disconnections

There have been a number of times in recent history where PEI was either completely disconnected from the mainland, or some portion of the electrical connection to the mainland was lost, resulting in emergency generation and load shed (emergency blackouts) to prevent total system failure.

- Complete disconnection from mainland: 4 events since 2004, of varying duration. The most recent event took place on November 29, 2018 and lasted approximately 8 hours.
- Partial disconnection from mainland, resulting in emergency generation / load shed: 5 events dating back to 2008. The most recent was on January 22, 2018.

More broadly, between 2019 and 2021, the on-island combustion turbines operated on 130 occasions, of which 42 of those occasions prevented either interruptible load having to be shed or wider system rolling blackouts. All remaining operation of the on-island combustion turbines were either to provide emergency energy to Nova Scotia Power / New Brunswick Power, perform required monthly test runs of the combustion turbines, or various transmission-related reasons. A breakdown of the reasons the combustion turbines were operated between 2019 and 2021 is provided in the following table.

Table 2-6 — Historical Reasons for Combustion Turbine Operation, 2019 – 2021

Resource	Number of Instances	Total MWh
Unit Testing	62	552
NB Power "Hold-to-Schedule"	52	2,106
Emergency Energy Supply to Others	10	569
On-Island Transmission Related	5	167
Curtailment by NB Power	1	91

Of the 130 occasions the combustion turbines had to operate, a common reason is due to "hold to schedule" events, which are discussed further below.

2.2.3.1. Hold to Schedule Events

There have been numerous events where on-island backup generation was operated to prevent interruptible load from being shed, or even rolling blackouts. Many of these events are categorized as "hold to schedule" events and occur when Maritime Electric is unable to import the full amount of electricity from the mainland needed to completely meet system load.

The most common reason for a "hold to schedule" event is when there is a sudden shortfall in island wind generation compared to what the wind generation was forecasted to be. Maritime Electric must tell NBEM how much electricity it plans to import from the mainland ahead of time. In order to determine the amount of electricity it needs to purchase and import, Maritime Electric must first use a forecast of island wind generation to determine how much electricity the PEI wind generators should be able to contribute over the course of the day to meeting system load. After accounting for the forecasted wind generation, Maritime Electric then forecasts how much electricity it needs to purchase from New Brunswick to serve any remaining load that will not be able to be fully met by the expected wind generation. Once Maritime Electric tells New Brunswick Power how much electricity it plans to purchase and import, any remaining unpurchased electricity available at the intertie between PEI and New Brunswick is often purchased by Nova Scotia Power. In the event the wind generation on PEI falls short of its forecast, Maritime Electric will be short on electricity to fully meet load and has to request additional electricity in real time from New Brunswick to make up for the shortfall. If there still is transmission capacity available, Maritime Electric can purchase and import the associated electricity to meet system load; however, if the electricity has already been previously purchased by Nova Scotia Power, or is unavailable for some other reason, Maritime Electric is required to "hold to [its original] schedule", and as a result must start its backup generators to make up for the shortfall in wind generation and meet system load.

Hold to schedule events are typically short in duration (i.e., an hour), but occur with relative frequency, primarily due to the difficulty of forecasting wind generation with complete accuracy all of the time.

2.2.4. Recommended Generation Capacity During Rolling Blackouts

While any instance that rolling blackouts occur is a serious emergency event, the severity of rolling blackouts can vary based on how much on-island generation capacity is available to be dispatched. Historically (through the mid- to late-2010's), Maritime Electric has had an amount of on-island dispatchable generation capacity (between its oil-fired and diesel-fired generators) equal to at least 50% of winter peak load (winter is the season where load is highest on PEI). Maritime Electric has been able to successfully navigate previous potential rolling blackout scenarios with this amount of dispatchable capacity; however, we note that Maritime Electric and PEI have also been fortunate in that the previous instances PEI has been disconnected from the mainland have been resolved within hours. Future events (i.e., large storms, hurricanes, etc.) that might damage key interconnection equipment could result in PEI being disconnected from the mainland for much longer periods of time.

With the recent retirement of the Charlottetown oil-fired generators, Maritime Electric has significantly less dispatchable generation capacity located on PEI that it can utilize to meet system load in the event that PEI is disconnected from the mainland. The retirement of the oil-fired generators has resulted in the amount of on-island dispatchable capacity falling from over 50% to approximately 30% of winter peak load (which includes the peak load reductions provided by DSM). This is shown in the following table.

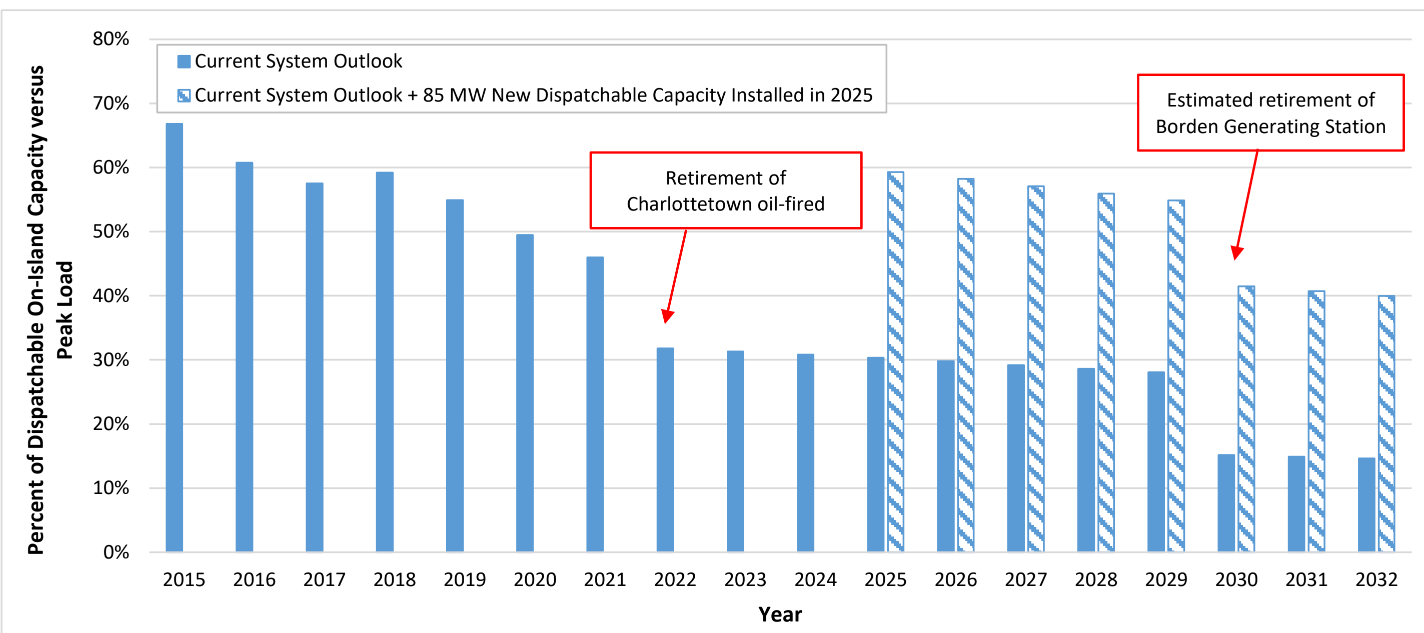
Table 2-7 — Outlook of Dispatchable On-Island Capacity vs. Peak Load

	Year *(2023 – 2032 are Forecasted Years)*													
	Average 2015-2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
MECL Peak Load (MW) (Net of DSM)	239	257	276	280	284	289	293	299	305	311	317	323	329	335
Charlottetown Thermal Plant (MW)	54	38	38	0	0	0	0	0	0	0	0	0	0	0
Borden Generating Station (MW)	40	40	40	40	40	40	40	40	40	40	40	0	0	0
Charlottetown CT3 (MW)	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Total (MW)	**143**	**127**	**127**	**89**	**89**	**89**	**89**	**89**	**89**	**89**	**89**	**49**	**49**	**49**
Ratio of Dispatchable On-Island Capacity to Peak Load (%)	**60%**	**49%**	**46%**	**32%**	**31%**	**31%**	**30%**	**30%**	**29%**	**29%**	**28%**	**15%**	**15%**	**15%**

As compared to the mid- to late-2010's, the current low amount of dispatchable on-island capacity (per peak load level) poses a significant risk to Maritime Electric's customers in the event of a disconnection from the mainland, as it will likely lead to more severe rolling blackouts than would have occurred in the past. There is not a consistent energy industry standard that identifies exactly what rolling blackout severity level is acceptable versus unacceptable; thus, it is difficult to identify the exact amount of dispatchable capacity Maritime Electric should have installed on PEI to manage the unique situations where PEI is electrically disconnected from the mainland. As such, our recommendation for how much dispatchable capacity Maritime Electric should have installed on PEI is based on the consideration that Maritime Electric was successfully able to navigate previous potential rolling blackout scenarios. During those previous scenarios, there was an amount of dispatchable capacity on PEI greater than or equal to (≥) 50% of peak load.

Accounting for the anticipated continued load growth on PEI, and also considering the continued growth of DSM on the island, approximately 85 MW of additional dispatchable capacity is required to bring the current ratio of dispatchable capacity to peak load back in line with the 50% historical threshold. Note that even with this amount of additional dispatchable capacity, there would likely still be a need for rolling blackouts to be implemented if PEI were disconnected from the mainland. The following figure illustrates the ratio of dispatchable on-island generation capacity versus peak load both historically and forecasted through 2032. A second set of data points are included on the figure to illustrate how the ratio of dispatchable capacity versus peak load increases if 85 MW of additional dispatchable capacity are added on PEI in 2025. Note that current estimates for the retirement of the Borden Generating Station (40 MW) is approximately 2030. Additional capacity, beyond the 85 MW assumed in 2025, would have to be added to the system in 2030 to replace Borden's retired 40 MW capacity to maintain a 50% ratio of capacity to peak load. The following figure does not add any additional capacity to replace Borden; however, it does illustrate the impact of Borden's retirement in terms of the capacity to peak load ratio.

Figure 2-5 — Outlook of Dispatchable On-Island Capacity vs. Peak Load



2.2.5. Battery Energy Storage During System Disconnection

Given the interest in and growth of BESS in electrical systems over the last decade, we have provided the following subsection to explain some of the capabilities and shortcomings of BESS in a situation where PEI were electrically disconnected from the mainland.

A key challenge if PEI's system is disconnected from the mainland grid is that there will likely not be enough generation to meet all system load. As a resource, BESS cannot generate energy, it can only transfer energy from one period of time to another; however, BESS can provide some portion of the system balancing needs (i.e., absorb excess wind generation or inject energy when wind generation is low). By meeting some portion of the island's balancing needs, BESS could allow PEI to utilize a larger amount of the on-island wind generating capacity in the event of an electrical disconnection to the mainland. For example, if wind generation was high one moment, the BESS could absorb some of the excess wind generation, which would allow the dispatchable generators on the island to operate at a more continuous MW level. Without the BESS, those dispatchable generators would otherwise have to lower output to make room for the high wind generation.

It is important to note that the ability for BESS to help meet the island's balancing needs is limited by the BESS state of charge at that point in time. The limitations would be that during low wind production periods, the battery would have to be sufficiently charged to be able to inject the necessary balancing energy, while in contrast, during high wind production periods, the BESS would need sufficient headroom to be able to absorb the excess wind energy. If the BESS were empty / fully charged when wind production was low / high (respectively), the BESS could not help balance the system at that moment. Since the BESS state of charge during a disconnection from the mainland is a function of 1) its state of charge when the mainland disconnection occurred 2) the output of the wind generators during the disconnection, and 3) the length of time it takes for PEI to be re-connected to the mainland, it is difficult to accurately forecast how much system balancing benefit BESS could provide PEI during a disconnection from the mainland.

For planning purposes, a worst-case scenario for PEI during a situation where the island was disconnected from the mainland would be a scenario where there was no wind generation, due to the wind not blowing, the wind blowing too strongly to operate the wind turbines, a transmission failure, or some other similar reason. In this scenario, the benefit of a BESS would be limited to the amount of energy it has stored (i.e., its state of charge) when the island was disconnected from the mainland, the BESS MW capacity, and the BESS duration (i.e., 2-hour, 4-hour, etc.). If this disconnection lasted for a significant period of time (e.g., as long as or longer than the 8-hour disconnection PEI experienced in 2018), the BESS would not be able to help the system for the full duration of the time PEI was disconnected from the mainland. In this situation, the BESS' energy reserves would be drained and there would be no way to recharge the BESS until a mainland connection was restored.

2.3. RENEWABLE AND SUSTAINABILITY TARGETS

Sustainability and reducing carbon emissions are two of Maritime Electric's most important goals. At present, 86% of the electricity that Maritime Electric delivers to its customers is generated using carbon-free resources. In 2021, Maritime Electric received the Sustainable Electricity Leader designation from Electricity Canada. Moving forward, Maritime Electric has established a greenhouse gas emissions reduction target to reduce emissions by 55% by 2030 (from 2019 levels). A detailed discussion regarding our recommended methods for how Maritime Electric can achieve this emissions reduction target is provided in Section 3.3. In addition, Section 3 provides a general overview of carbon emissions planning considerations related to Maritime Electric's portfolio.

2.4. REGIONAL GENERATION PLANNING CONSIDERATIONS

Given that PEI purchases a significant amount of both energy (over 75%) and generation capacity (over 60%) from its neighbours, it is important to consider the generation plans of PEI's neighbours when assessing what types of / how many resource additions PEI will require moving forward. As such, S&L reviewed planning documents from New Brunswick Power, Nova Scotia Power, and Hydro Québec.

2.4.1. Coal Power Plant Retirements

The government of Canada has committed to phasing out conventional coal-fired power plants by 2030. This commitment will have a significant impact on the generation portfolios of both New Brunswick and Nova Scotia. At present, coal generation accounts for the following amounts of capacity in these provinces:

- New Brunswick: 467 MW, or 12.3% of the province's total generating capacity
- Nova Scotia: 1,234 MW, or 41.2% of the provinces total generating capacity

Both the New Brunswick Power and Nova Scotia Power Integrated Resource Plans (IRPs) postulate scenarios where their coal generation is retired in 2030. In both IRPs, the scenarios that retire coal in 2030 require substantial modifications to each utility's overall generation portfolio.

- ***New Brunswick Power:*** At the time the 2020 New Brunswick IRP was written, New Brunswick Power considered the continued operation of the 467 MW Belledune Coal Power plant until 2040 via an equivalency agreement with the government to be the most cost-effective and likely plan for the future. Since the publication of the IRP, the government has mandated that the coal power plant must retire by 2030. The IRP did explicitly consider a scenario where coal is retired by 2030 and noted that electricity imports and renewable energy / storage are not feasible solutions to replacing the retired coal capacity from Belledune. Instead, the IRP postulated potentially building a new natural gas power plant or small modular nuclear reactors to replace the coal capacity. At present, it is uncertain how New Brunswick will replace the retired coal capacity.

- ***Nova Scotia Power:*** Given coal generation makes up a significant percentage of Nova Scotia Power's total generation capacity (41.2%), the retirement of coal generation in Nova Scotia by 2030 necessitates substantial changes to Nova Scotia's generation portfolio. The Nova Scotia IRP considers that the retired coal generation will be replaced with a combination of new natural gas power plants, wind and solar farms, demand response, imported capacity, and energy storage. From an energy perspective, the Nova Scotia IRP estimates that wind generation and imported energy will be primarily how generation from coal is replaced in the future. Additionally, given Nova Scotia will have an increased reliance on imported capacity and energy following the retirement of coal generation in 2030, the top item noted in the IRP's action plan is the development of a regional integration / interconnection strategy to better connect Nova Scotia electrically to the rest of the Canadian provinces and the North American mainland.

- ***Hydro Québec:*** The impact on Hydro Québec due to the retirement of coal generation in Canada by 2030 will be primarily demand-based. Hydro Québec operates a sizable fleet of hydroelectric power plants, with a total hydroelectric capacity of 36,700 MW. The retirement of coal generation in the region is likely to result in an increased demand for capacity and energy from Hydro Québec's power plants. In addition, the United States has been an important consumer of Hydro Québec's hydroelectric generation. Sales of electricity from Hydro Québec to the United States averaged approximately 25 TWh in 2021, which is 30% higher than a decade ago[12]. As the United States works towards meeting its own decarbonization goals, demand from the United States for Hydro Québec's generation is likely to increase. In fact, Hydro Québec recently signed major long-term power purchase agreements with both Massachusetts and New York, each for approximately 10 TWh annually[13]. Finally, Québec's own electricity demand is expected to grow substantially over the next decade. Hydro Québec estimates that their system load will grow by 20 TWh between 2019 and 2029 (a 12% regional load increase). To meet these challenges, Hydro Québec is implementing a robust energy efficiency policy and also has a long-term plan to install another 5,000 MW of renewable generating capacity, consisting primarily of both hydroelectric (2,000 MW installed by 2035) and wind generation (3,000 MW installed by 2026).

From the perspective of PEI, the retirement of coal in Canada by 2030 will result in significant changes to the generation portfolios of PEI's immediate neighbours. While PEI's neighbours are planning on developing new capacity, the level of investment and mobilization needed to replace the retired coal capacity is significant considering that the retirement deadline for the coal power plants is less than a decade away. In addition, there is a forecasted increase in energy and capacity demand from Nova Scotia

[12] https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/electricity/statistics/electricity-trade-summary/index.html
[13] https://www.hydroquebec.com/data/documents-donnees/pdf/strategic-plan.pdf?v=2022-03-24

and the northeastern United States. All of this is likely to result in more competition for regional energy and capacity if the development of new generating resources and the implementation of regional energy efficiency programs cannot keep pace with demand growth. An increase in demand without similar corresponding increase in supply has the potential to result in higher costs for Maritime Electric's customers.

2.4.2. Mactaquac Generating Station Life Extension Project

Given that Maritime Electric imports a substantial amount of both system capacity and energy from New Brunswick, S&L reviewed the New Brunswick Power Corporation's 2020 IRP to determine whether any planned changes occurring in New Brunswick with respect to generation might impact Maritime Electric's ability to import electricity and capacity into PEI. One important consideration is the Mactaquac Generating Station life extension project.

The Mactaquac Generating Station is a 668 MW hydroelectric power plant that provides a significant amount of renewable generation to New Brunswick and the surrounding areas, including PEI. This power plant is one of the most important in the region due to both its large size and dispatchability, in addition to the fact that it is a zero-carbon emitting generator. For reference, the Mactaquac Generating Station accounts for just under 18% of New Brunswick Power Corporation's 3,790 MW generating capacity.

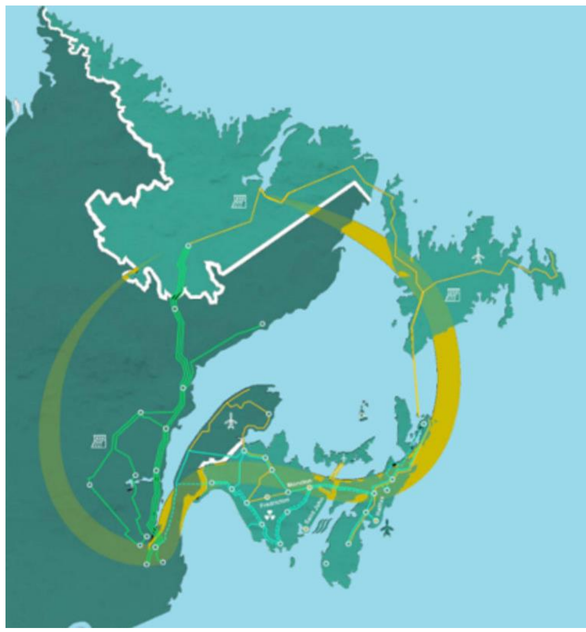
Related to the Mactaquac Generating Station, The New Brunswick Power Corporation notes that "since the 1980s, concrete portions of the station have been affected by a chemical reaction called an alkali-aggregate reaction. This reaction causes concrete to swell and crack. This results in significant annual maintenance and repairs. Without additional capital improvements, the station is expected to reach the end of its service life in 2030." As a result, the New Brunswick Power Corporation has recommended a life extension project for the power plant to make necessary repairs and improvements, ultimately allowing the power plant's life to extend to 2068. As of the writing of the New Brunswick Power Corporation's 2020 IRP, this project is expected to start in 2027 and end in 2033. During the project, the output of the power plant will be limited. The life extension project would be a significant capital expense and would require substantial engineering expertise. Estimates for project costs are varied but appear to be in the CAD $3 billion range or higher.

Given the scale of this project and the importance of the power plant to the region, S&L is of the opinion that there is some uncertainty regarding whether New Brunswick will be able to or willing to sell Maritime Electric enough generator capacity and energy to fully meet Maritime Electric's obligations. The timely progress and success of the life extension project is important for PEI given how reliant PEI is on capacity and energy from New Brunswick. In the event that the Mactaquac Generating Station life extension project experiences schedule delays or there are deratings beyond what is planned, New Brunswick will have less capacity and energy available to sell to neighbours; thus, it would be more difficult for Maritime Electric to secure sufficient capacity and energy at a reasonable price from New Brunswick.

2.4.3. Regional Transmission Improvements

From an electrical perspective, the increased demand for zero-carbon electricity in the region, including the northeastern United States, will require significant regional transmission upgrades to transport the electricity longer distances. One such proposed large scale project is the Atlantic Loop Project, which would create a transmission loop through eastern Canada so that zero carbon energy could be transported to the Maritime Provinces from Quebec and Labrador. A diagram of the proposed project is included below.

Figure 2-6 — Proposed Atlantic Loop Project Diagram[14]



Given the size of the project, different levels of Canadian governments involved, and sizable investment required, a final decision on whether the project will be fully implemented has not been made. As a result, there is uncertainty surrounding whether the transmission system will be able to accommodate the increased clean energy imports and exports between Canadian provinces (and between Canada and the United States) in the future. For PEI, this results in another layer of uncertainty surrounding the potential challenge of securing sufficient energy and capacity from the mainland in the future. This challenge is compounded from the fact that there will likely be an increase in demand for imported capacity and energy as coal is retired in Canada by 2030.

[14] Clean power Roadmap for Atlantic Canada, https://www.nrcan.gc.ca/sites/nrcan/files/energy/images/publications/2022/A%20CLEAN%20POWER%20ROADMAP%20FOR%20ATLANTIC%20CANADA-ACC.pdf

2.5. ENERGY CONTRACTS

Currently, Maritime Electric purchases over 60% of the energy it needs to serve system load through a contract (energy purchase agreement, or EPA) with NBEM. The EPA with NBEM is a comprehensive and complex agreement, but in general is based around the framework that the energy Maritime Electric purchases from NBEM follows a fixed rate structure. This agreement offers Maritime Electric a number of important benefits.

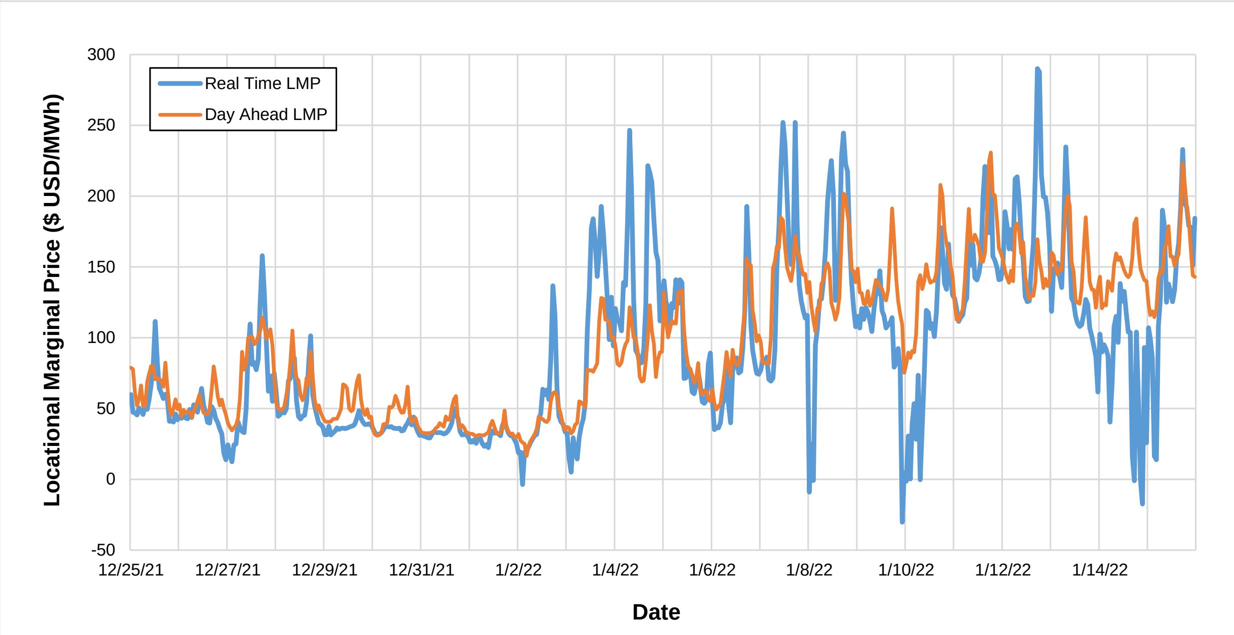
The contract provides some level of price volatility insulation for Maritime Electric's customers, especially when compared to an alternative where Maritime Electric instead purchased energy that varies in price on an hourly basis, as is the case in an energy marketplace. A large amount of generation supplied to Maritime Electric from NBEM is generated by New Brunswick Power, which has both a diverse generation portfolio and has a current surplus of generation capacity. As such, New Brunswick Power is able to provide their customers some level of price hedging against market forces that would otherwise increase the cost of power generation. Through the EPA with NBEM, Maritime Electric is also able to partially benefit from New Brunswick Power's generation portfolio's ability to hedge against market forces.

If Maritime Electric were instead part of an energy marketplace like nearby ISO-New England, Maritime Electric's customers would be directly exposed to power prices that vary on a real-time basis. At times, this may be beneficial for customers due to low power prices; however, at other times power prices could be very high. A utility like New Brunswick Power, which has excess generation capacity, is able to reduce/avoid purchases from a marketplace when prices are high because New Brunswick Power instead could dispatch their own power plants to generate electricity at less cost than purchasing it from the high-priced marketplace. However, Maritime Electric has a shortage of generation capacity installed on-island relative to its peak load. As a result, Maritime Electric would still be forced to buy significant amounts of energy from a marketplace during high-priced periods even if Maritime Electric dispatched their own generators during these times.

The following figure illustrates a recent period of energy price volatility in ISO-New England. Figure 2-7 shows hourly locational marginal prices (LMPs) for electricity (in USD $/MWh), for both day-ahead prices and real-time prices, between the end of December 2021 through the beginning of January 2022. Prices are taken from the node that represents the tie between ISO-New England and New Brunswick. As can be seen in the figure, prices both increased and became much more volatile in the beginning of January 2022 due to a combination of cold weather, high electrical demand, and the high price of natural gas (both gaseous and liquified). While infrequent, prices in energy marketplaces can reach levels much higher than those shown in the graph. For example, during the polar vortex event in Texas in 2021 prices touched USD $9,000/MWh, which was equal to the price cap set by ERCOT, the Texas grid operator.

Figure 2-7 — ISO-New England Locational Marginal Prices (USD)[15]

At the ISO-New England Tie to New Brunswick, December 2021 to January 2022



While the existing EPA with NBEM does not fully insulate Maritime Electric from macro-market forces that impact the cost of electricity production, it does provide significantly more price certainty than if Maritime Electric met its energy obligations through a marketplace, which is reflected in Maritime Electric's rates.

2.5.1. Energy Storage Arbitrage

Electricity price arbitrage is a use-case for BESS that has seen significant growth in popularity. Energy arbitrage is an economic use-case for BESS that is accomplished by buying energy from a marketplace when energy costs are low and storing the energy until energy costs are high. Once prices are high, the energy is re-injected (sold) into the electricity system. The difference between the purchase price and injection price is profit for the utility, net the efficiency losses of the storage system.

The potential for installing a BESS on PEI and utilizing it for arbitrage is discussed in detail in the recently released report, *Prince Edward Island Resource Planning and Maritime Electric Capital Expenditures, Alternatives to MECL Integrated System Plans and Impact on MECL Capital Expenditures*, developed by Synapse Energy Economics. A requirement in order to engage in an energy arbitrage trading strategy is participation in an energy marketplace (e.g., ISO-New England). At present, Maritime Electric does not currently trade energy in an energy marketplace. Maritime Electric could decide to join an energy

[15] Source: ISO-New England LMP pricing information, https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/lmp-by-node

marketplace in the future; however, this would amount to a change in Maritime Electric's corporate strategy and would require additional investigation to weigh the various pros/cons and coordinate with Maritime Electric's stakeholders/oversight entities. Given that Maritime Electric has a shortage of on-island generation capacity relative to its peak load (described further in the previous section), it is not recommended that Maritime Electric join an energy marketplace in lieu of an agreement with NBEM or similar organization (i.e., exclusively purchase energy through a marketplace instead of through a contract with an entity like NBEM) as this would force Maritime Electric's to meet a significant portion of its energy needs via a marketplace, exposing its customers to much higher energy price volatility.

3. CARBON EMISSIONS PLANNING

This section provides an overview of PEI's electrical system from a carbon emissions perspective, comparisons of PEI to its neighbours, and a discussion of how PEI might reduce carbon emissions moving forward. The goal of this section is to provide the reader a firm understanding of both where Maritime Electric's electrical system is today with respect to carbon production and the most effective changes/policies Maritime Electric/PEI can implement to reduce carbon production in the future.

3.1. MARITIME ELECTRIC SYSTEM OPERATION

As discussed in Section 2.1, Maritime Electric has historically met the energy needs of its customers on PEI with energy purchased from the Point Lepreau Nuclear Generating Station, energy purchased from the wind farms located on PEI, and energy purchased from the agreement with NBEM. Between 2019 and 2021, these three resources combined to provide over 99% of the energy Maritime Electric utilized to meet system load. Solar energy and energy generated by Maritime Electric's diesel generators provided the remaining generation. It is important to note that the energy purchased through NBEM has historically helped Maritime Electric not only meet load, but also provide critical load- and renewable- balancing support, and frequency / voltage support needed for system electrical stability. The ability for Maritime Electric to purchase the exact amount of energy it needs in real time from NBEM allows Maritime Electric to balance the variable generation from PEI's wind farms. This in turn has allowed PEI to integrate an increasing amount of wind generation on the island.

3.1.1. Load and Renewable Balancing Resources

As more wind and solar energy is installed on PEI, resources that provide load- and renewable-balancing support will become more important for Maritime Electric because higher amounts of installed wind and solar capacity will result in an increase in the magnitude of generation from the wind and solar farms. For example, currently a total of 92.5 MW of wind capacity is contracted with Maritime Electric. A very windy hour could result in 92.5 MW of generation from the wind farms. If the wind then calmed, a large portion of that wind generation will disappear. By contrast, if another 70 MW of wind capacity was contracted with Maritime Electric, a windy hour could result in 162.5 MW of wind generation. If the wind calmed in this scenario, the drop in total wind generation would be greater than in the current system with only 92.5 MW of wind generation. As a result, more balancing resources will be needed to manage these larger swings in generation.

There are many different types of resources that can provide load- and renewable-balancing support for Maritime Electric. Currently, purchases from NBEM are the primary resource that provide this support. Other options that can provide this support in electrical systems are fast-ramping engines / combustion turbines and BESS. At present, Maritime Electric's diesel generators are capable of providing load- and renewable-balancing support to the system, but Maritime Electric rarely utilizes these generators for that purpose due to the fact that they are more expensive to dispatch and produce more carbon emissions (on a per kWh basis) than purchasing energy from NBEM. New engines / combustion turbines could utilize renewable fuels (i.e., biodiesel), which would be an improvement from a carbon emissions perspective; however, purchases from NBEM would still likely be a more cost-effective option than utilizing new engines/combustion turbines.

BESS is also a resource than can be utilized to provide load- and renewable-balancing support to electrical systems. The challenge with utilizing BESS to serve this need on PEI is that there are efficiency losses when charging/discharging a BESS resource, typically on the order of 10% to 15% for lithium-ion batteries. These efficiency losses are significantly higher than the 1.7% transmission losses associated with importing energy from the mainland. The only times a BESS resource could charge in a way that would benefit the system from a carbon emissions perspective would be during hours when the total wind plus nuclear generation exceeds system load. During those hours, the excess generation that would otherwise have to be sold back to the mainland could be stored in the BESS and used at a later time.

To illustrate system operation with and without a BESS, during times when high wind output would result in excess total generation (total generation greater than system load), the following example shown in Table 3-1 was developed. In the example, two scenarios are presented – one without a BESS resource and one with a BESS resource. In both scenarios, two consecutive hours are illustrated. Wind generation for both scenarios is high during hour 1 (190 MW), then falls for hour 2 (100 MW). Nuclear generation from Point Lepreau is consistent at 29 MW for both hours. In both scenarios, during hour 1 there is excess generation equal to 19 MW due to high wind farm output (system load is only 200 MW for hour 1, while total generation is 219 MW). In the scenario without the BESS, the excess 19 MW has to be sold back to the mainland, but in the scenario with the BESS, the excess 19 MW is used to charge the BESS for re-injection back into the system in the second hour. During the second hour, the battery can only inject 16.2 MW of energy back into the system because the battery is only 85% efficient (19 MW x 85% = 16.2 MW).

As can be observed in the example, the scenario with the BESS resource is able to increase the total amount of carbon free MWh utilized by PEI from 329 MWh to 345.2 MWh, while reducing the amount of MWh that have to be purchased from NBEM from 71 MWh to 54.9 MWh. By reducing the amount of MWh purchased from NBEM, the battery is able to help Maritime Electric reduce its carbon emissions.

Table 3-1 — Example A: Comparison of Battery Operation

Battery only charges when there is excess wind + nuclear generation

	Wind + Nuclear Generation Exceeds Load in Hour 0 No BESS is Installed		Wind + Nuclear Generation Exceeds Load in Hour 0 BESS Installed and Charges from Wind	
	Hour 1	Hour 2	Hour 1	Hour 2
System Load (MW)	**200**	**200**	**200**	**200**
Imported Nuclear Generation (MW)	29	29	29	29
Wind Generation (MW)	190	100	190	100
BESS Charge (-) / Discharge (+) (MW)	-	-	-19	16.2
Imports from NBEM (MW)	0	71	0	54.9
Total Generation + Imports (MW)	**219**	**200**	**200**	**200**
Excess generation sold back to mainland (MW)	19	0	0	0
Wind + Nuclear + BESS That Stays on PEI (i.e., Carbon Free MWs Not Sold Back to Mainland)	**200**	**129**	**200**	**145.2**
Sum of Hour 1 + Hour 2 (MWh)	**329**		**345.2**	
Total MWh Imports from NBEM (Hour 0 + Hour 1) (i.e., Non Carbon Free MWs)	**0**	**71**	**0**	**54.9**
Sum of Hour 1 + Hour 2 (MWh)	**71**		**54.9**	

Currently, total wind plus nuclear generation on PEI very rarely exceeds system load; thus, the BESS would rarely be able to charge as is shown in the above example. The number of times when wind generation plus nuclear generation exceeds system load will increase as more wind generation is installed on PEI. In an effort to quantify how effective BESS would be able to help contribute to systemwide carbon emissions reductions, an hourly calculation of system generation and emissions with and without BESS was developed for various amounts of wind generation. The calculation methodology and results are presented in Section 3.2.1 and generally finds that the benefit (in terms of both carbon emissions reductions and carbon emissions reductions per dollar invested) a BESS resource could provide is modest.

If instead the BESS resource was allowed to charge from the wind generation during hours where the wind plus nuclear generation was less than system load (as it is for most hours in the current system), the round-trip efficiency losses of the BESS would result in less overall wind generation being utilized on the island than if the BESS was not used at all. This in turn would require more purchases from NBEM, and higher carbon emissions for the island.

To better illustrate this, the previous example was recreated assuming the wind generation equals 100 MW for both hours 1 and 2. In the example, system operation for the scenario without a BESS resource is identical for both hours due to the fact that both the wind generation and nuclear generation are consistent. In the scenario with the BESS, the BESS charges 19 MW during hour 1, then discharges 16.2 MW during hour 2 – consistent with the previous example. As can be seen in the example that follows, when the BESS resource charges during times when there is not excess generation (e.g., when wind plus nuclear generation is less than system load), total purchases from NBEM increase from 142 MWh to 154.9 MW, indicating that it is actually worse for Maritime Electric from a carbon emissions perspective than if the BESS did not operate / if there was no BESS installed. The reason for this is that the round-trip efficiency losses of the BESS result in some carbon-free generation being lost when the BESS charges/discharges.

Table 3-2 — Example B: Comparison of Battery Operation

Battery charges when there is not excess wind + nuclear generation

	Wind + Nuclear Generation is Less than Load in both Hour 0 and Hour 1 No BESS is Installed		Wind + Nuclear Generation is Less than Load in both Hour 0 and Hour 1 BESS Installed and Charges from Wind	
	Hour 1	Hour 2	Hour 1	Hour 2
System Load (MW)	**200**	**200**	**200**	**200**
Imported Nuclear Generation (MW)	29	29	29	29
Wind Generation (MW)	100	100	100	100
BESS Charge (-) / Discharge (+) (MW)	-	-	-19	16.2
Imports from NBEM (MW)	71	71	90	54.9
Total Generation + Imports (MW)	**200**	**200**	**200**	**200**
Excess generation sold back to mainland (MW)	0	0	0	0
Wind + Nuclear + BESS That Stays on PEI (i.e., Carbon Free MWs Not Sold Back to Mainland)	**129**	**129**	**110**	**145.2**
Sum of Hour 1 + Hour 2 (MWh)	**258**		**255.2**	
Total MWh Imports from NBEM (Hour 0 + Hour 1) (i.e., Non Carbon Free MWs)	**71**	**71**	**100**	**54.9**
Sum of Hour 1 + Hour 2 (MWh)	**142**		**154.9**	

3.2. CARBON EMISSIONS FOR MARITIME ELECTRIC

Of the three main resources that Maritime Electric has historically utilized to meet system load, energy purchased from both Point Lepreau and the wind farms on PEI do not generate carbon emissions. Energy purchased through NBEM is generated from a variety of different types of power plants located throughout New Brunswick, Nova Scotia, Québec, and the United States. As a result, a portion of the energy purchased through NBEM is generated from power plants that release carbon emissions.

For reference, historical generation in GWh and carbon emissions in tonnes CO2e for Maritime Electric between 2019 and 2021 is provided in Table 3-3.

Table 3-3 — Maritime Electric Historical Generation and Emissions by Source

Source	Average Historical Generation (2019-2021)[1]	% of Total	Historical Carbon Emissions (Tonnes CO_2e)[2]	% of Total
MECL Diesel Generators	1.2[3]	0.1%	1,233	0.5%
Customer-Owned Generation (i.e., net-metered solar)	3.9	0.3%	0	0%
PEI Wind Farms	295.3	21.0%	0	0%
Point Lepreau Nuclear Generating Station	210.0	14.9%	0	0%
Purchases from NBEM	898.1	63.7%	253,389	99.5%
Total	1,408.5[3]	100.0%	254,622	100.0%

Notes/Sources:

1) Historical generation data provided by Maritime Electric.
2) Carbon emissions rates for Maritime Electric are taken from the 2022 Maritime Electric Sustainability Report (https://www.maritimeelectric.com/Media/1959/2022-sustainability-report_final_interactive-pdf_july-28-2022.pdf).
3) The average historical net generation of Maritime Electric's generators is -0.5 GWh, due to the fact that these units are primarily on standby (and to be kept on standby the generators must draw a small amount of electricity from the grid). In addition, between 2019 and 2021 the Charlottetown oil-fired generators used an average of 3.3 GWh per year while being retired from service. Shown in the above table is the generation of the diesel generators, not including the electricity they used from the system. The total system generation would average 1,403.5 GWh if both the net generation from the diesel generators and the electricity used from the Charlottetown oil-fired generators was considered.

It should be noted that a significant portion of the energy purchased from NBEM is from non-carbon emitting sources. In fact, 86% of the electricity Maritime Electric delivered to its customers (as of 2021) was generated using non-carbon emitting sources[16].

For comparison, Table 3-4 is included to illustrate carbon emissions rates for a variety of different northeast Canadian utilities and other planning regions. From a carbon emissions perspective, Hydro Québec and Newfoundland and Labrador Hydro are the regional leaders in terms of low carbon emission energy production. The vast majority of the electricity these utilities deliver to their customers is generated with in-province hydroelectric power plants, which do not generate carbon emissions. New Brunswick Power has a diverse portfolio of many different types of generators, including those that generate carbon emissions (e.g., the Belledune and Coleson Cove generating stations) and those that are carbon free (e.g., Mactaquac hydro and the Point Lepreau nuclear power plant), while Nova Scotia Power has a number of operating coal-fired power plants, which tend to generate carbon emissions at a higher rate than other power generation technology.

The emissions rates for Nova Scotia Power and New Brunswick Power are set to be reduced in the coming years as a result of the Canadian government's mandated retirement of coal power plants by 2030. This

[16] Taken from page 23 of the 2022 Maritime Electric Sustainability Report (https://www.maritimeelectric.com/Media/1959/2022-sustainability-report_final_interactive-pdf_july-28-2022.pdf)

would result in Maritime Electric's carbon emissions falling if it were to continue its energy purchase agreement with NBEM.

Table 3-4 — Historical Carbon Emissions Rates for Various Utilities/Locations

Utility	2019-2021 Average Carbon Emission Rates (kg/kWh)
Maritime Electric[1]	0.195
Nova Scotia Power[2]	0.621
New Brunswick Power[3]	0.295
Hydro Québec[4]	0.001
Newfoundland and Labrador Hydro[5]	0.026
ISO-New England[6]	0.250
All of Canada[7]	0.110
All of United States[8]	0.386

Notes/Sources:

1) Carbon emissions rates for Maritime Electric are taken from the 2022 Maritime Electric Sustainability Report (https://www.maritimeelectric.com/Media/1959/2022-sustainability-report_final_interactive-pdf_july-28-2022.pdf) and are all inclusive of electricity produced by Maritime Electric's generators, imported electricity, vehicle emissions, building heating, and other related items.
2) Carbon emissions for Nova Scotia are taken from Nova Scotia Power's emission reporting database (https://www.nspower.ca/cleanandgreen/air-emissions-reporting) and are inclusive of electricity produced by Nova Scotia Power's generators and imported electricity.
3) Carbon emissions for New Brunswick are taken from the Canada Energy Regulator database (https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-new-brunswick.html). Emissions rates are based on 2019 and 2020 data as data for 2021 is not provided.
4) Carbon emissions rates for Hydro Quebec are taken from the following source: https://www.hydroquebec.com/data/developpement-durable/pdf/d-5647-affiche-co2-2021-an-vf.pdf
5) Carbon emissions rates for Newfoundland and Labrador Hydro are taken from the Canada Energy Regulator database (https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-new-brunswick.html). Emissions rates are based on 2019 and 2020 data as data for 2021 is not provided.
6) Carbon emissions rates for ISO-New England are taken from the 2020 ISO-New England Electric Generator Air Emissions Report (https://www.iso-ne.com/static-assets/documents/2022/05/2020_air_emissions_report.pdf)
7) Carbon emissions rates for Canada are taken from the Canada Energy Regulator database for 2020 (https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-canada.html#:~:text=The%20greenhouse%20gas%20intensity%20of,%2FkWh%20(Figure%208).)
8) Carbon emissions rates for the United States are taken from the U.S. Energy Information Agency website for 2020 (https://www.eia.gov/tools/faqs/faq.php?id=74&t=11#:~:text=In%202020%2C%20total%20U.S.%20electricity,CO2%20emissions%20per%20kWh).

It is important to note that while Hydro Québec and Newfoundland and Labrador Hydro have a significant amount of carbon free generating capacity, there currently is a lack of electricity transmission infrastructure in place to support a large-scale increase in energy exports from these utilities throughout the region. In the event that regional transmission infrastructure is expanded, Maritime utilities would likely benefit from long term clean energy contracts with Hydro Québec and/or Newfoundland and Labrador Hydro. Currently Québec and New Brunswick are exploring adding additional transmission capacity between the provinces. In addition, the proposed Atlantic Loop Project would create a transmission loop through eastern Canada so that zero carbon energy could be transported through the region. A diagram of the proposed project is included in Figure 2-6 and duplicated below.

Figure 3-1 — Proposed Atlantic Loop Project Diagram[17]

Given the size of the project, different levels of Canadian governments involved, and sizable investment required, a final decision on whether the project will be fully implemented has not been made. As a result, the transmission system cannot currently accommodate a substantial increase in energy imports and exports between Canadian provinces.

It is also important to note that there is a strong likelihood that any future purchases from Hydro Québec and/or Newfoundland and Labrador Hydro that Maritime Electric might be able to secure would be for energy only, and potentially on an interruptible basis. As such, Maritime Electric would need to find alternative means to meet its regional capacity obligations, either through generation capacity installed on PEI or purchased from the mainland.

3.2.1. Carbon Emissions Improvement From Battery Energy Storage

In order to help quantify how much the addition of battery energy storage on PEI could be able to help reduce Maritime Electric's carbon emissions, an hourly calculation of system generation and emissions was developed. The calculation estimated emissions for a variety of different scenarios. The scenarios considered include three different levels of island wind generation:

[17] Clean power Roadmap for Atlantic Canada, https://www.nrcan.gc.ca/sites/nrcan/files/energy/images/publications/2022/A%20CLEAN%20POWER%20ROADMAP%20FOR%20ATLANTIC%20CANADA-ACC.pdf

1. Current system installed wind capacity, for a total system nameplate capacity equal to 92.5 MW, current system (2022) load
2. Additional 70 MW of wind capacity, for a total system nameplate capacity equal to 162.5 MW, expected 2025 system load
3. Additional 120 MW of wind capacity (in addition to Scenario 1), for a total system nameplate capacity equal to 212.5 MW, expected 2025 system load

The wind capacity in Scenario 1 represents the current system, while the wind capacity in Scenario 2 represents the likely amount of installed wind that will be under contract with Maritime Electric in the near future (potentially by 2025). Scenario 3 represents a more aggressive wind development plan and is included for comparison purposes and future planning. Both Scenarios 2 and 3 consider an estimated hourly load forecast for 2025, while Scenario 1 considers the current hourly system load.

For each of the scenarios, different BESS installation cases are considered. Our estimate of the capital costs associated with the BESS systems is also provided, based on our detailed capital cost buildups detailed in Appendix A.

a) No BESS is added to PEI
b) A single 50 MW, 2-hour BESS (100 MWh storage) is added to PEI (CAD $78 Million)
c) A single 50 MW, 4-hour BESS (200 MWh storage) is added to PEI (CAD $134 Million)
d) A single 50 MW, 8-hour BESS (400 MWh storage) is added to PEI (CAD $244 Million)

Calculations are based on the assumption that the addition of BESS to the island would allow Maritime Electric to better manage the generation from the wind power plants installed on PEI. Currently, during times when the wind generation causes total system generation to exceed system load, Maritime Electric is forced to sell excess PEI wind energy to the mainland. At present, the frequency at which this occurs is very low; however, it would likely occur at a higher rate in the future as more wind power plants are installed on PEI. The addition of BESS could store some, or all, of the excess wind generation for re-injection at a later time. Maritime Electric could then reduce the amount of energy it needs to purchase from the mainland by instead using the re-injected wind energy from the BESS. Since the energy from the mainland is generated using some carbon-emitting power plants, the addition of BESS would help Maritime Electric reduce carbon emissions.

The model developed to investigate carbon emissions performs calculations on an hourly basis, then presents the results on an annual basis. Calculations are based on historical Maritime Electric hourly system load and generation data from the last four years. The BESS is modeled such that it charges off wind energy that otherwise would have to be sold back to the mainland due to energy oversupply. The modeled BESS then injects this energy back into system after total system generation falls below system load. The energy the BESS injects back into the system displaces energy that would otherwise have to be imported from New Brunswick or generated by Maritime Electric's diesel-fired generators. In addition, the model conservatively assumes the BESS is able to further reduce the amount that the diesel-fired Maritime Electric generators operate by 100% (this assumption is conservatively high as the addition of BESS cannot completely eliminate the need for the island's diesel-fired generation). The modeled BESS is assumed to have an 85% round trip efficiency. At a high level, the calculation provides a simplified look in the potential benefits of BESS from a carbon reduction perspective versus the capital investment of the BESS.

The results of the analysis are provided in Table 3-5. The data reported includes the following variables:

- **Gross wind generation (MWh)**: This variable is the estimated total amount of on-island wind generation that is purchased by Maritime Electric annually. It includes both the wind generation that Maritime Electric is able to sell to their customers, in addition to generation that might have to be sold by Maritime Electric to the mainland as a result of generation oversupply during some subset of hours in the year.
- **Wind generation sold to MECL customers (MWh)**: This is the annual PEI wind generation that is sold to the Maritime Electric customers. The addition of BESS helps to increase this variable because the BESS is able to absorb some portion of the energy that would otherwise have to be sold to the mainland (due to periods where there is energy oversupply) and inject it back into the system at a later time.
- **Percent of PEI wind generation purchased by MECL that is sold to MECL customers (%)**: This is the ratio of the two previous variables.
- **Total generation carbon emissions, all electricity delivered to MECL customers (tonnes CO_2e)**: This variable tracks the estimated amount of carbon emissions associated with the electricity that Maritime Electric sells to their customers. This variable includes estimated carbon emissions associated with electricity purchased from mainland power plants (via NBEM), based on NBEM's most recent carbon emissions rates (tonnes CO_2e vs GWh produced).
- **Carbon emissions ratio for all electricity delivered to MECL customers (kg/kWh)**: The carbon emissions ratio is the amount of carbon emissions per kWh. This variable is useful to track carbon emissions rates from one location to another, such as to the locations in Table 3-4.
- **Percent of electricity sold to MECL customers that is carbon free (%)**: This variable tracks the percentage of MWhs that Maritime Electric sells to their customers that are generated with carbon free resources.

The results of the analysis indicate that with the amount of wind generation installed on PEI currently, there are very few times when high wind generation results in there being an oversupply of electricity generation on the island. As a result, with the amount of wind capacity installed on PEI today, a BESS system is not needed to shift excess wind generation to other times.

As more wind is installed on the island, there are more times when there will be an oversupply of electricity generation. As a result, BESS becomes more beneficial; however, the benefit is fairly modest. For example, an addition of a 50 MW, 4-hour BESS to the scenario with 70 MW of additional wind (162.5 MW of wind capacity total) yields a reduction in overall carbon emissions of just 1.2% (from 219,074 to 216,350 tonnes CO_2e) from the scenario without BESS. Considering the level of investment required for a 50 MW, 4-hour BESS system (estimated at CAD $134 million), we consider the associated reduction in overall carbon emissions from BESS to be a low value for PEI on a dollars-invested per carbon reduction perspective. The cost per carbon reduction is calculated equal to CAD $49 thousand per tonne CO_2e reduction for the BESS system. By comparison, the addition of 70 MW of wind generation on the island is estimated to reduce future carbon emissions by 14% (from 254,622 to 219,074 tonnes CO_2e) without considering BESS. This reduction in carbon emissions is over 10x higher than that resulting from the addition of the 4-hour BESS alone. Furthermore, we estimate that the cost of adding 70 MW of additional onshore wind generation would be similar to cost of adding a 50 MW, 4-hour BESS; however, on a dollars-invested per carbon reduction perspective, wind would be considerably less expensive. The cost per carbon reduction is calculated equal to CAD $4 thousand per tonne CO_2e reduction for the onshore wind. Detailed cost comparisons of the various technologies considered in this report are provided in Appendix A.

There are a significant number of times when high wind generation results in an oversupply of overall electricity generation on the island in the scenario where 120 MW of additional wind is operational (212.5 MW of wind capacity total). BESS provides the highest benefit in terms of improving overall carbon emissions in this wind capacity scenario; however, the benefit is still fairly small, especially for the smaller-sized BESS cases. A key takeaway from this scenario is that PEI and Maritime Electric should have a plan on how to manage excess electricity generation as higher amounts of wind are installed on the island. S&L did not investigate alternative approaches to managing this generation beyond BESS; however, one alternative approach would be to address this contractually, whether with the wind generators, PEI's neighbours, or other parties, in such a way that provides more flexibility for the island and maximizes value for customers. This is discussed more in Section 3.3.

Table 3-5 — Estimated Portfolio Carbon Emissions with New Battery Storage

Parameter	No BESS	50 MW, 2-hr BESS (100 MWh)	50 MW, 4-hr BESS (200 MWh)	50 MW, 8-hr BESS (400 MWh)
Estimated BESS Capital Cost ($ CAD)	**-**	**$78 M**	**$134 M**	**$244 M**
Current system installed wind capacity (92.5 MW), current system load				
Gross wind generation (MWh)	295,552	295,552	295,552	295,552
Wind generation sold to MECL customers (MWh)	295,267	295,384	295,405	295,448
Percent of PEI wind generation puchased by MECL that is sold to MECL customers (%)	99.90%	99.94%	99.95%	99.96%
Total generation carbon emissions, all electricity delivered to MECL customers (tonnes CO_2e)	254,622	254,588	254,583	254,571
Carbon emissions ratio for all electricity delivered to MECL customers (kg/kWh)	0.181	0.181	0.181	0.181
Percent of electricity sold to MECL customers that is carbon free (%)	85.7%	85.7%	85.7%	85.7%
Current system installed wind capacity + 70 MW new wind capacity (162.5 MW), estimated 2025 load				
Gross wind generation (MWh)	571,475	571,475	571,475	571,475
Wind generation sold to MECL customers (MWh)	557,461	563,319	566,034	567,928
Percent of PEI wind generation puchased by MECL that is sold to MECL customers (%)	97.55%	98.57%	99.05%	99.38%
Total generation carbon emissions, all electricity delivered to MECL customers (tonnes CO_2e)	219,074	217,116	216,350	215,816
Carbon emissions ratio for all electricity delivered to MECL customers (kg/kWh)	0.141	0.139	0.139	0.139
Percent of electricity sold to MECL customers that is carbon free (%)	88.9%	89.0%	89.0%	89.0%
Current system installed wind capacity + 120 MW new wind capacity (212.5 MW), estimated 2025 load				
Gross wind generation (MWh)	768,564	768,564	768,564	768,564
Wind generation sold to MECL customers (MWh)	694,799	707,178	715,646	727,100
Percent of PEI wind generation puchased by MECL that is sold to MECL customers (%)	90.40%	92.01%	93.11%	94.61%
Total generation carbon emissions, all electricity delivered to MECL customers (tonnes CO_2e)	180,327	176,529	174,140	170,909
Carbon emissions ratio for all electricity delivered to MECL customers (kg/kWh)	0.116	0.113	0.112	0.110
Percent of electricity sold to MECL customers that is carbon free (%)	90.8%	91.0%	91.1%	91.3%

3.3. EFFECTIVELY REDUCING CARBON EMISSIONS

Maritime Electric's 2022 Sustainability Report presents a goal of reducing greenhouse emissions by 55% by 2030. Achieving this goal will require Maritime Electric to implement substantial changes to how it serves load. This section discusses the most effective methods Maritime Electric and PEI can pursue to help reduce carbon emissions.

- **Integration of additional wind generation on PEI**: Frequent and strong winds are one of PEI's best resources from a power generation perspective. The capacity factors of the most recently developed wind farms on PEI frequently see levels approaching 50% or higher, which is among the highest in the energy industry for land-based wind generation. PEI has already integrated a significant amount of wind generation on the island (through development by the PEI Energy Corporation); however, the further development of wind generation on PEI would be one of the most effective ways Maritime Electric could achieve their greenhouse gas reduction goals by 2030. For reference, Maritime Electric is anticipating an additional 70 MW of wind generation being developed on PEI through the PEI Energy Corporation, operational in near future.

  One challenge that Maritime Electric will have to address as more wind generation is developed on PEI is how best to manage times when there may be excess wind generation beyond system load. Currently, this occurs very infrequently, but it will occur with more frequent regularity as higher levels of wind capacity are integrated. As illustrated in the previous sections, the addition of BESS onto PEI would only be able to marginally improve the system from the perspective of managing excess wind generation and improving carbon emissions for Maritime Electric. As a result, BESS is not recommended to address this challenge. Instead, Maritime Electric may be required to address this challenge contractually, whether with the wind generators, PEI's neighbours, or other parties.

  Specifically, Maritime Electric might pursue contracts that allow more flexibility, favorable terms, and/or alternative financial arrangements to better address the higher likelihood of curtailment of the island wind power plants. For example, Maritime Electric could pursue payment structures with a price per MWh that varies by hour/season, with the price for the hours with the highest likelihood of curtailment being lowest. Maritime Electric might also explore including a fixed per MW price structure (either in addition to or replacing the per MWh price structure), which would help to fix the payments for the wind generation per month, while also sharing some of the cost burden of curtailment with the wind project owner (since the wind project owner would have to forecast project curtailment in order to properly determine its best per MW price). Alternatively, Maritime Electric might be able to set up an agreement with a mainland offtaker, like New Brunswick Power or Nova Scotia Power, to buy any excess wind generation for a fee.

  In addition, as more wind generation is integrated onto PEI, the importance of load- and renewable-balancing resources increases. At present, energy purchased through NBEM is used to meet Maritime Electric's system balancing needs. With more integrated wind generation, there will be larger swings in totaled (summed) hourly generation from the wind farms. If load- and renewable-balancing needs were continued to be met with energy purchased from NBEM, the larger swings in hourly generation from PEI's wind would be more costly for mainland generators to balance. These costs would ultimately be passed contractually onto Maritime Electric and their customers.

While wind generation is a great source of carbon free energy, it is not a good source of generation capacity due to its intermittent nature (see Appendix C). As a result, even with a large number of on-island wind power plants, Maritime Electric will need to meet their required capacity obligations using other resources, whether installed on the island or purchased from the mainland. This is discussed in detail in Section 2.1.

Finally, the continued integration of wind generation will necessitate transmission upgrades on PEI, especially in the western portion of the island where there is considerable wind energy interest but a lack of the necessary transmission facilities to transport the energy. Without these upgrades, it will not be possible for large amounts of additional wind generation to be added to the system.

- **Further implementation of demand-side management**: A low-cost and effective solution that would help to reduce PEI's carbon emissions is a prudent DSM program. DSM focuses on reducing energy consumption using a variety of methods, including integrating modern technologies (e.g., smart meters, push communications, etc.), influencing customer behavior (e.g., through time-of-use electricity rates, education, etc.), and by improving system efficiency. Currently, PEI's DSM plan is managed by the efficiencyPEI. The successful growth and adoption of PEI's DSM plan will help to partially offset the expected energy consumption growth in PEI resulting from both population increase and the PEI residents' continued transition away from oil-fired heating to electrical heating in homes. Any reductions in energy consumption from DSM would equate to fewer MWh purchased from the mainland, which would result in both carbon emission reductions and cost savings for Maritime Electric's customers.
- **Integration of additional solar generation on PEI**: The addition of solar generation onto PEI will help to reduce carbon emissions on the island. In addition, solar PV is among the lower cost generation technologies available today. Given PEI's solar resource is much lower than PEI's wind resource (the expected capacity factor for new wind farm on PEI is near 45%, while the expected capacity factor for a new solar PV power plant on PEI is approximately 20% - see Appendix D for detailed calculations), the priority should be to develop additional wind generation on PEI. However, additional solar PV can provide carbon-free energy diversity to Maritime Electric's generation portfolio at a relatively low cost; thus, should be part of the solutions Maritime Electric can utilize to reduce carbon emissions moving forward[18].

  Similar to wind generation, solar PV generation is a good source of carbon free energy, but it is not a good source of generation capacity due to its intermittent nature. Given this, Maritime Electric will still need to meet their regulatory capacity obligations using other resources, whether installed on the island or purchased from the mainland. This is discussed in detail in Section 2.1.

Two additional considerations that are likely to help Maritime Electric reduce carbon emissions are included below. While Maritime Electric does not have direct control over the implementation of these items, their implementation/progress is likely to benefit Maritime Electric and PEI.

- **The retirement of coal generation in Canada by 2030**: While Maritime Electric does not own any coal power plants, some portion of the energy it purchases through the NBEM EPA is generated from coal power plants. As a result, the retirement of coal throughout Canada by 2030, along with

[18] Net metering small-scale renewable energy installations such as rooftop solar can cause cross-subsidization issues where non-solar customers are in effect subsidizing the system costs of solar customers.

the further decarbonization of the power sector in Canada, will benefit Maritime Electric from a carbon emissions perspective as it continues to purchase energy from the mainland.

- **Expansion of regional transmission capacity**: As discussed previously, Hydro Québec and Newfoundland and Labrador Hydro have a significant amount of carbon free hydroelectric generating capacity and future generating capability; however, there currently is a lack of electricity transmission infrastructure in place to support a large-scale increase in energy exports from these utilities throughout the region. If regional transmission infrastructure is expanded, Maritime utilities would be able to benefit from long term clean energy contracts with Hydro Québec and/or Newfoundland and Labrador Hydro. It is important to note that there is a strong likelihood that any future purchases from Hydro Québec and/or Newfoundland and Labrador Hydro that Maritime Electric might be able to secure would be for energy only, and potentially on an interruptible basis. As such, Maritime Electric would need to find alternative means to meet its regional capacity obligations, either through generation capacity installed on PEI or purchased from the mainland.

4. CAPACITY RESOURCE COMPARISON

4.1. TECHNOLOGIES CONSIDERED

This section compares a number of different capacity resource technologies based on initial input from both Maritime Electric and S&L. The list of technologies considered is provided below:

- Wind power, both onshore and offshore
- Solar power, both photovoltaic (PV) utility and rooftop scale, and concentrating solar power (CSP)
- Battery energy storage systems (BESS), lithium-ion, other storage technologies
- Reciprocating internal combustion engine (RICE), operating both on traditional and renewable fuels
- Combustion turbines (CT), aeroderivative models, operating both on traditional and renewable fuels
- Biomass power plant, operating on different types of biomass
- Nuclear power plant, small modular reactor (SMR)
- Tidal stream power plant or wave power plant
- Geothermal power plant
- Fuel cells

The following subsections provide an overview of the different technologies listed above, including considerations specific to PEI.

4.1.1. Wind Power

Wind energy is produced from wind turning the blades of a turbine which in turn spins a generator, creating electricity. Wind energy is a renewable source of power that releases no carbon emissions. The amount of power generated is dependent on the real-time wind speed; thus, generation from wind power plants is variable.

Wind turbines can be placed either onshore or offshore. Offshore wind generally provides higher, more consistent energy outputs than onshore wind because of the typically higher and more consistent wind speeds over bodies of water. However, onshore wind is much less expensive than offshore wind because the construction of offshore wind power plants is more complex and extensive than that of onshore power plants. Construction of offshore wind farms is more challenging as boats and special equipment are required. Offshore turbines also typically require more maintenance than those onshore due to various environmental factors, including corrosion facilitated by salt in the ocean.

Consistent and strong wind speeds are one of PEI's best resources from a power generation perspective. New wind farms on PEI could approach a 50% capacity factor on an annual basis, which is among the highest in the energy industry for onshore wind farms. Maritime Electric already has under contract a total of 92.5 MW of wind capacity that it utilizes to serve load, and an additional 70 MW of wind generation is planned. Wind is a clean energy source and its continued development on PEI will be a key part in helping Maritime Electric to achieve its carbon emission reduction goals.

Table 4-1 — Wind Energy Advantages and Disadvantages

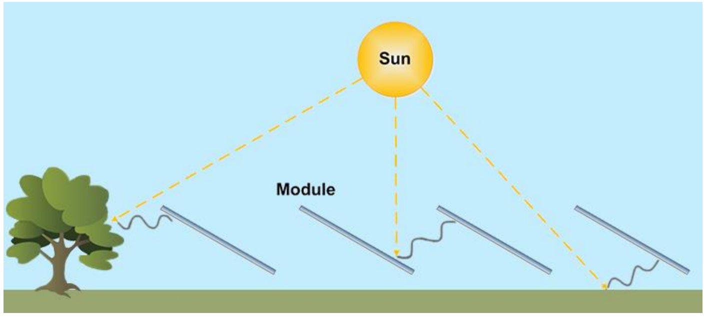
Wind Energy Advantages	Wind Energy Disadvantages
Renewable energy source, no carbon emissions	Intermittent generation profile, not a good source of generation capacity, other resources needed to balance wind generation and load
There are strong and consistent wind speeds on PEI, making the location very suitable for wind generation	Inverter-based resource, at high penetration levels additional planning considerations may be required to maintain electrical stability
Cost effective resource (onshore wind)	High levels of wind integration on PEI will require transmission/system electrical upgrades
Technology has a long and successful service history in the energy industry	Offshore wind is more expensive to construct and maintain

4.1.2. Solar Power

Utility-scale and rooftop solar photovoltaic (PV) both employ solar panels to convert energy from the sun into usable electricity. Energy from the sun is absorbed by PV cells that make up the solar panel. This energy creates electrical charges on the atomic level within the PV cell. These charges create an electric current that is used as electricity. Solar PV is a renewable source of energy. Since the production of electricity from solar PV is based on the energy provided by the sun, electricity production is limited based on the time of day and weather conditions. Solar PV power plants have seen significant growth in popularity over the most recent decades due to their low cost and simplicity.

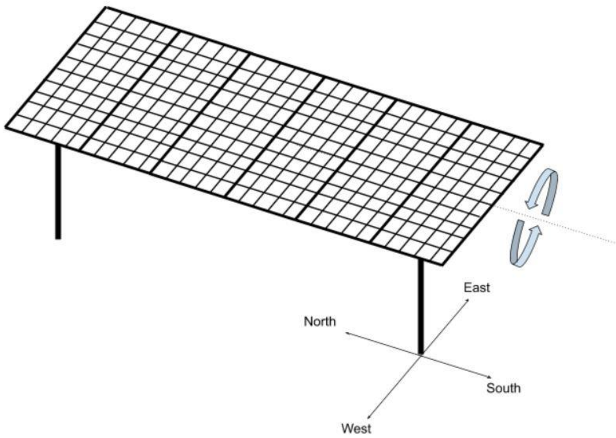
There are different types of PV panels and racking configurations that can impact/improve a solar PV power plant's generation. Solar power plants can utilize monofacial or bifacial solar panels. Monofacial panels are one sided and very common in the energy industry, while bifacial panels have grown in popularity over the most recent years and have the ability to absorb the sun's light on both the front and the reverse side of the panel. Bifacial panels are more expensive than monofacial panels but can help to increase the generation of a solar power plant, especially in locations where the ground reflectivity is high (i.e., light colored ground, snow, etc.). Bifacial panels are typically only used in utility-scale solar power plants, not in small-scale rooftop applications, because they require some ground clearance to maximize the amount of reflected light to the reverse side of the panel. Figure 4-1 provides a simplified illustration of how a bifacial solar PV panel works.

Figure 4-1 — Illustration of Bifacial Solar PV Panel



The two most common racking configurations are fixed-tilt and single-axis tracking. A fixed-tilt racking configuration is simple, in that during construction the panels are initially orientated in such a way that maximizes the amount of solar energy the panels can capture. The panels remain orientated in this position for the lifetime of the project. Fixed tilt configurations are relatively inexpensive and common both for utility-scale projects and in smaller-scale rooftop applications. In a single axis tracking configuration, panels are affixed to a motorized tracker that follows the sun throughout the day on a single axis, keeping the panels always in a position that maximizes the amount of solar energy they are able to absorb. Single-axis tracking helps to increase the amount of solar energy absorbed by the panels over a fixed-tilt configuration, especially during the morning and late afternoon, when the sun is lowest on the horizon. Figure 4-2 is a simple illustration of how a single-axis tracking configuration operates.

Figure 4-2 — Illustration of Single-Axis Tracking PV Configuration



For PEI, solar PV generation is a viable renewable resource that can help Maritime Electric lower carbon emissions. Due to PEI's northern latitude and climate, the potential generation from solar PV installed in PEI will be lower than sites located closer to the equator / in arid climates. S&L developed forecasts of the expected solar generation on PEI using the program PVsyst. PVsyst is a commonly used solar PV design and forecasting program utilized in the energy industry. Four different cases were run:

1. A fixed-tilt racking configuration with monofacial solar panels
2. A fixed-tilt racking configuration with bifacial solar panels
3. A single-axis tracking racking configuration with monofacial solar panels
4. A single-axis tracking racking configuration with bifacial solar panels

Each forecast incorporates PEI-specific solar irradiation and climate data, along with S&L's project assumptions regarding expected project design, module layout, electrical and system losses, etc. The results are developed for 10 MW solar PV power plants and include capacity factor, expected annual generation for the 10 MW power plant, and also the expected annual generation if five 10 MW power plants are installed. Detailed PVsyst reports of the different systems are provided in Appendix D. For comparison to the data in the table below, the newest wind power plants on PEI achieve capacity factors of just under 50%. A new 50 MW wind power plant on PEI might expect to generate over 200,000 MWh annually.

Table 4-2 — Solar PV Forecasts

Configuration	Expected Capacity Factor	Expected Annual Generation, 10 MW Power Plant (MWh)	Expected Annual Generation, 5x10 MW Power Plants (MWh)
Fixed Tit, Monofacial Panels	19.2%	16,840	84,200
Fixed Tit, Bifacial Panels	19.9%	17,440	87,200
Single-Axis Tracking, Monofacial Panels	20.9%	18,290	91,450
Single-Axis Tracking, Bifacial Panels	22.4%	19,590	97,950

For PEI, S&L has modeled a fixed-tilt, bifacial configuration. While it is feasible to build a single-axis tracking configuration on PEI, the island's cold climate could make it more challenging to reliably operate a tracking system due to ice and snow buildup on components. Our recommendation of bifacial panels stems from the fact that bifacial panels tend to work well in locations that see snow accumulation (like PEI), due to the high reflectivity of snow.

Table 4-3 — Solar PV Advantages and Disadvantages

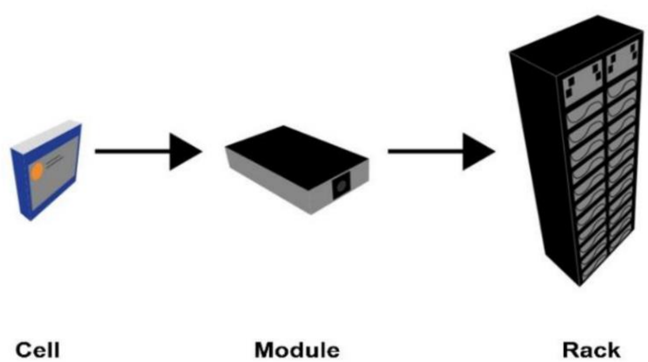
Solar Energy Advantages	Solar Energy Disadvantages
Renewable energy source, no carbon emissions	Intermittent generation profile during the day due to cloud cover, not a good source of generation capacity, other resources needed to balance PV generation and load
Cost effective resource	No generation at night
Technology has a long and successful service history in the energy industry	Inverter-based resource, at high penetration levels additional planning considerations may be required to maintain electrical stability
Different module types and racking configurations can boost the amount of energy generated	Large amounts of land required for a utility-scale solar PV power plant

Another type of power plant that utilizes solar energy to generate electricity is a concentrated solar power (CSP) plant. There are different CSP plant configurations, but one common type of CSP plant captures direct solar radiation by reflecting it to a central receiving tower using mirrors. The reflected solar energy heats the central receiving tower, which contains a high temperature fluid or molten salt that absorbs the energy. The heated liquid is then used to produce steam, which drives a steam turbine to produce electricity. Alternatively, a plant can be designed such that mirrored troughs are used to reflect sunlight into a fluid flowing through a pipe. The heated fluid drives a steam cycle. S&L has worked on a number of different CSP plants across the globe. These types of power plants are best suited for arid climates that receive very high amounts of solar irradiance, for example the Atacama Desert in Chile, various locations in Spain, the southwest United States, etc. Due to its location and climate, PEI is not a suitable location for a CSP plant.

4.1.3. Energy Storage

Energy storage systems store energy generated at one time for use at another time. A battery energy storage system (BESS) consists of many electrochemical batteries that collect energy from the power source and discharge that energy to the grid when it is needed. A BESS can be utilized for numerous different purposes including energy time shifting, providing system capacity, ancillary services, transmission support, renewable and load balancing, and other similar purposes. A BESS can be designed for more than one use case. Lithium-ion BESS is the most common battery type employed in the energy industry due to cost, thermal properties, and life-cycle benefits. A distinct advantage of a BESS project is that it can inject energy into an electrical system virtually instantaneously. A typical lithium-ion BESS arrangement is provided below in Figure 4-3.

Figure 4-3 — Typical BESS Arrangement



A lithium-ion BESS typically has a round trip efficiency of 85-90%, meaning that between 10%-15% of energy entering the battery is lost during the storage process. In addition, a BESS degrades with usage, which results in the need to augment the BESS and add additional batteries to the system in order for the BESS to continue to achieve its originally designed performance levels. BESS projects are not required to perform augmentation; however, an un-augmented BESS project might expect to see performance degradation on the order of 25% to 30% over a 20-year lifespan. The amount of energy stored by a BESS project can vary from project to project based on the size of the battery installed. Like wind and solar PV generators, BESS is an inverter-based resource.

Table 4-4 — Lithium-Ion BESS Advantages and Disadvantages

Lithium-Ion BESS Advantages	Lithium-Ion BESS Disadvantages
Many different potential use cases, including load / renewable shifting, capacity resource, ancillary services, energy arbitrage, etc.	A BESS can only shift electricity from one point in time to another, it cannot generate electricity
Technology has wide adoption in the energy industry	10% to 15% of the energy is lost in the storage process
Energy can be injected instantaneously	A BESS system degrades with usage (and thus must be periodically augmented with additional battery cells in order to maintain consistent performance levels). Alternatively, a BESS can be initially overbuilt to account for performance degradation
A BESS is modular and relatively simple to augment / expand	Inverter-based resource, at high penetration levels additional planning considerations may be required to maintain electrical stability

While there are other types of BESS technologies, lithium-ion BESS is the type that is predominantly utilized in the energy industry. For example, flow batteries are a similar technology to that of lithium-ion batteries but employ a tank of liquid electrolyte to charge and discharge separate from the electrodes. Flow batteries can provide longer storage with little to no degradation as compared to lithium-ion batteries; however, the round-trip efficiency is typically lower than lithium-ion batteries (typically in the 65% to 80% range). Currently, flow battery technology has not been widely adopted for use in the energy industry. For this reason, it is not recommended for Maritime Electric's generation portfolio at this point in time.

Compressed air energy storage (CAES) is another storage technology that has yet to see mainstream adoption in the energy industry but offers promise for the future. In a CAES system, electricity is used to power an air compressor, then air is pumped and pressurized into an underground cavern or tank. When it is needed, the air is released through a turbine to produce electricity. Significant amounts of air can be stored for long periods of time. A drawback of compressed air storage as compared to lithium ion batteries is that a CAES system typically has a lower round trip efficiency. On a utility scale, there are only a handful of CAES systems in service today. There is significant risk associated with being an early adopter of a technology; thus, a CAES system is not recommended for Maritime Electric at this point in time.

4.1.4. Reciprocating Internal Combustion Engine

A reciprocating internal combustion engine (RICE) operates by converting heat and pressure generated by the combustion of fuel into mechanical energy. Energy is derived from a set of pistons, where the fuel is ignited within the piston and the subsequent increase in pressure drives the piston outward. Engines are common in the power industry, in automobiles, and in many other applications. While the acronym "RICE" technically refers to all types of engines, it is commonly used in the energy industry and by electric utilities to refer to large electricity-producing engines. From a fundamental perspective, utility-scale RICE generators are essentially the same as what an individual might find in an automobile, just the size of a utility-scale engine is much bigger and utility-scale engines are used to spin an electrical generator, rather than an automobile's wheels.

In general, RICE generators are a mature technology that offer a combination of modularity and dispatch flexibility. The modular aspect of RICE relates to the fact that individual engines are small in size (typically less than 20 MW); thus, power plants can be economically constructed to meet load demands of virtually any size (i.e., for larger loads, a utility can simply purchase more engines). The flexible nature of engines is related to their ability to start up / shut down and ramp up / down quickly and with little, if any, associated increase in operational costs or performance degradation. Over the last ten years, S&L has seen an uptick in utility interest in RICE power plants due to their modularity, dispatch flexibility, and competitive development and operations costs. Utilities have also found that the flexible dispatch capabilities of RICE power plants complement renewable energy well: an engine's ability to start and ramp quickly can help to offset the variable generation profiles of wind and solar energy. For PEI, an engine would serve virtually exclusively as a backup generator, dispatching only during the times when enough energy could not be procured from the mainland, during emergencies (i.e., disconnections from the mainland), or other similar situations. RICE would serve this purpose well.

There are a number of companies that manufacture engines that would fit the needs of PEI. In addition, modern engines are relatively fuel efficient, with heat rates typically around 8,500 Btu/kWh in a simple cycle configuration. A benefit of RICE is that it can operate on a variety of different fuels, including diesel fuel, natural gas, biodiesel, a mixture of natural gas and hydrogen, and pure hydrogen likely within 3 to 5 years[19]. Some modification to the engine components would be required to convert an engine to operate on very different fuels. For example, modifications would be required to convert an engine that primarily operates on diesel/biodiesel to be able to operate on hydrogen, but in general, the variety of fuels compatible with RICE would help PEI to reduce the risk of having a stranded asset if Canadian regulations changed the allowable fuels that could be used for power generation. For reference, traditional diesel and biodiesel are similar enough in composition that many of the most common RICE units available today can fire either without needing significant modifications (some minor modifications to balance of plant equipment/storage would be required to allow for biodiesel firing).

[19] Per recent discussions with engine original equipment manufacturers that S&L commonly work with

From a carbon emissions perspective, RICE does produce carbon dioxide when burning diesel fuel, natural gas, and biodiesel. Carbon emissions when burning natural gas are significantly lower than when burning diesel fuel. Biodiesel combustion produces lower emissions than typical diesel fuel; however, the lifecycle emissions (considering net emissions from the entire production process of the fuel) of biodiesel are much lower than typical diesel fuel. In fact, the lifecycle emissions are low enough that the government of Canada considers biodiesel as a renewable fuel[20].

Table 4-5 — RICE Advantages and Disadvantages

RICE Advantages	RICE Disadvantages
Mature, dispatchable technology with ability to generate power over long periods of time, so long as fuel is available	Generates carbon emissions (however these can be lowered depending on the fuel used)
Power plants can be built modularly, larger power plants would simply add more engines	In larger applications (i.e., > 200 MW), other thermal technologies can be more cost effective and fuel efficient
Can operate on a variety of different fuels, including fuels classified as renewable	Engines are noisy and require noise attenuation
Flexible generation: ability to start up / shut down and ramp up / down quickly	Requires fuel to operate

4.1.5. Combustion Turbine

Combustion turbines (CT) work similarly to RICE but rather use a turbine instead of a piston to generate electricity. Air is drawn into a compressor, where it is pressurized and fed into the combustion chamber. The fuel mixes with the air and combusts, creating a high-pressure gas that expands and drives a turbine to produce electricity. There are two types of combustion turbines: frame (industrial) and aeroderivative (which share many similarities to the jet engines that power airplanes). In general, the differences between the aeroderivative and frame turbines are weight, size, combustor and turbine design, bearing design (antifriction bearings for aeroderivative turbines and hydrodynamic ones for frame turbines), and the lube oil system. Frame combustion turbines are also field erected and maintained in place, whereas aero-derivative turbine plants are designed for a quick replacement of the entire engine when maintenance is required.

CTs have a representative heat rate of 9,000 to 10,000 BTU/kWh in a simple cycle configuration, which makes them less efficient than RICE. When compared to a RICE, CTs provide a smaller footprint per MW output. CTs can run on various fuel types including diesel fuel, natural gas, biodiesel, a mixture of natural gas and hydrogen, and pure hydrogen likely in the near future (at present there are not yet commercially available CTs that can operate on 100% hydrogen). Because of the combustion process, CTs emit carbon and other greenhouse gases. Alternative fuel sources can help to reduce or eliminate carbon emissions.

[20] https://www.nrcan.gc.ca/energy-efficiency/transportation-alternative-fuels/alternative-fuels/biofuels/biodiesel/3509

Modifications to the CT components would be required to convert a CT to operate on different fuel types, and in general these modifications would be slightly more extensive than might otherwise be required to convert a RICE unit. For example, while a RICE unit would not require modifications to be able switch from traditional diesel to biodiesel outside of some minor changes to the balance of plant (BOP) and storage systems, a CT would require specialized equipment such as compatible fuel injection nozzles, combustors, etc., to be able to operate on biodiesel (in addition to the changes to the BOP and storage systems that would also be required for a RICE unit). We estimate the cost of the CT equipment modifications would be modest, in the CAD $2.5 to $3.0 million range, for a CT size in the 30 MW range.

CTs are a mature technology with fast startup and ramping capabilities. The technology is used throughout the energy industry for a wide variety of different purposes. Similar to RICE, the flexible dispatch capabilities of CTs complement renewable energy well: CT's ability to start and ramp quickly can help to offset the variable generation profiles of wind and solar energy. For PEI, a CT would serve predominantly as a backup generator, only needed to produce electricity in the event that a sufficient amount of energy cannot be imported from the mainland (which occurs on an infrequent basis throughout the year), during emergencies, or other similar situations.

Table 4-6— Combustion Turbine Advantages and Disadvantages

Combustion Turbine Advantages	Combustion Turbine Disadvantages
Mature, dispatchable technology with ability to generate power over long periods of time, so long as fuel is available	Generates carbon emissions (however these can be lowered depending on the fuel used)
Can operate on a variety of different fuels, including fuels classified as renewable	Requires a separate diesel generator for black start capability
Flexible generation: ability to start up / shut down and ramp up / down quickly	CTs can be noisy for those that are nearby when they are operating, may require noise attenuation
Small land footprint per MW output	Requires fuel to operate

4.1.6. Biomass Burning Power Plant

Biomass power generation facilities rely on the combustion of biomass to generate power. Biomass is fed into the power plant's combustion chamber and burned to produce high-pressure steam. The steam is used to turn a turbine and produce electricity. The type of biomass used to power these generators typically consists of crops, wood, municipal waste, or other organic matter.

Due to the relatively low energy content of solid biomass fuel (e.g., wood typically has approximately 30%-50% of the energy content of commonly used petroleum fuels on a per-mass basis), a significant amount of biomass is required to fuel a power plant. This translates to the power plant requiring very large plots of land to grow the necessary fuel. As an example calculation, a 50 MW biomass power plant operating 70%

of the year (a biomass power plant would likely need to operate as a baseload facility due to its operational inflexibility) would consume approximately 3,990,000 MMBtu of fuel in energy each year (a typical biomass power plant heat rate is 13,000 Btu/kWh). Assuming the fuel is pelletized wood, the energy content of wood varies by wood type, but a value of approximately 17 MMBtu/ton is a reasonable estimate. This equates to approximately 235,000 tons of wood required per year. While trees vary in weight based on their size, if each tree utilized weighed 1 ton, this would equate to 235,000 trees required per year to fuel the biomass power plant. As a rough estimate, assuming a tree farm can support 1,000 trees per acre, the power plant would need to cut down and replant approximately 235 acres of tree farmland per year. Furthermore, since trees take many years/decades to grow and thus could not be re-harvested immediately, trees from different 235-acre plots of land would have to be harvested each year until the original re-planted trees were mature. Ultimately, thousands of acres of land could be needed to grow the required fuel to support the operation of a biomass power plant.

In addition, due to the fundamental design of a biomass power plant as a large water boiler, a biomass power plant is not typically able to start / ramp output quickly relative to other thermal technologies like engines or combustion turbines. Biomass power plants also require a significant amount of staff to operate (as compared to other technologies like RICE or CTs).

Biomass power plants are considered renewable resources by the Canadian government, so long as the rate of consumption of the biomass does not exceed the rate of biomass regeneration. Burning of biomass in a power plant does release carbon dioxide; however, the net lifecycle emissions (which include the carbon dioxide absorbed by the biomass as it grows) are substantially less than that of thermal power plants that consume traditional fossil fuels.

Table 4-7 — Biomass Advantages and Disadvantages

Biomass Advantages	Biomass Disadvantages
Considered a renewable resource as a result of the net lifecycle emissions	Large land requirements required to grow the required biomass fuel
Flexible to run on various biomass types (i.e., trees, crops, etc.)	Combustion byproducts are emitted at the power plant
Dispatchable generator	Power plant is not capable of starting / ramping output as quickly as other generation types, i.e., is a relatively inflexible generator

4.1.7. Small Modular Nuclear Reactors

A significant amount of research into nuclear power has been ongoing over the most recent decades, and the technology that shows significant promise is small modular reactors (SMRs). Recent developments in the engineering of SMRs have broadened the potential applications of nuclear power with increased flexibility, safety, and ease of implementation. Nuclear fission has a legacy of reliable carbon-free power generation, and advanced SMR technology presents an attractive option for utilities interested in strengthening their portfolios with emission-free on-demand generation. These smaller reactors are well suited to be installed individually or in multiple-reactor configurations and distributed in locations where generation is needed, thereby reducing the costs and challenges of long-distance transmission associated with larger centralized installations.

Light water reactor designs generating 300 MW or less are typically considered to be SMRs. A traditional nuclear plant normally consists of one to two reactors, each capable of producing hundreds to more than 1,000 MW. The SMR concept allows a site to design to its demand, offering solutions not traditionally suitable for large nuclear plants, and scalability by allowing the addition of modules as demand grows. More than 70 SMR concepts are currently under development across the world.

As with all nuclear power plants, proper disposal of the used fuel is an important consideration. In addition, development of an SMR power plant would require significant capital investment, permitting/licensing, and time to develop. Given Maritime Electric's need to have additional capacity operational in the short term, an SMR was not selected as a short-listed technology due to the long amount of time it would take for a new SMR power plant to be operational.

Table 4-8 — Nuclear-SMR Advantages and Disadvantages

Nuclear-SMR Advantages	Nuclear-SMR Disadvantages
Carbon-free energy source	Waste disposal must be managed
SMR power plants can be built modularly	Long lead time for permitting / licensing, design, and construction

4.1.8. Tidal and Wave Power

Tidal and wave energy derive their power from the ocean. Tidal energy is power produced by capturing the surge of the ocean waters during the rise and fall of the tides. There are three types of tidal power: tidal barrage, tidal stream, and tidal lagoon. A tidal barrage employs a large dam with underwater turbines. The barrage gates open as the tide is coming in and shut at high tide, creating a pool behind the barrage. The tidal barrage then functions much like a dam, slowly letting water out through the turbines, generating electricity. A tidal lagoon functions similarly to the barrage with the difference being that the lagoon is manmade by a barrier along the coast. Unlike the barrage, the lagoon would be able to harness power as it is filling and emptying, allowing for more continuous power. Tidal stream power involves the use of underwater turbines. This is similar to wind generation; however, potentially more powerful since water has a much higher density than wind. Wave power generates electricity by harnessing the energy in ocean waves. There are different potential designs; however, many utilize floating pistons that move with the waves, generating electricity. All forms of tidal power and wave power are heavily location dependent. If the location of interest does not have high enough tides, or strong enough waves, the power output would be low. At present, there are only a handful of tidal power facilities in operation today. Similarly, wave power is still primarily a demonstration-stage technology and has not seen energy industry acceptance. From this perspective, there would be a risk for Maritime Electric to deploy either tidal or wave power in that they would be early adopters of the technologies.

Table 4-9 — Tidal and Wave Energy Advantages and Disadvantages

Tidal and Wave Energy Advantages	Tidal and Wave Energy Disadvantages
Clean energy with no carbon emissions	Location dependent on large tidal regions
Harnessing tides / waves effectively has the potential to generate large amounts of electricity	Technologies have little to no industry acceptance – there are only a handful of operating tidal power plants globally and wave power is still in the demonstration phase

4.1.9. Geothermal

Geothermal power is derived from harnessing heat from within the earth. Geothermal power plants are renewable resources. To capture the heat, wells can be drilled into the earth to pipe steam or hot water to the surface. This steam/hot water is then used to power a turbine that generates electricity. Different types of geothermal technologies exist, specifically dry, flash, and binary cycle. The choice of technology is typically dependent on the temperature of the geothermal source. While the fuel source is reliable and the technology has mainstream acceptance in the energy industry, geothermal power plants are highly dependent on location as they require a geothermal heat source to operate. The removal of steam and water from the ground can increase the risk of earthquakes and ground instability in the area. Due to its location and lack of geothermal resource, PEI is not a suitable location for a geothermal power plant.

Table 4-10 — Geothermal Advantages and Disadvantages

Geothermal Advantages	Geothermal Disadvantages
Renewable, clean energy source	Location dependent, requires geothermal resource
Dispatchable power plant with large net capacity	Gases / pollution can be released during drilling
Geothermal resources are long term sources of heat (e.g., as long as the geothermal resource remains hot, electricity can be produced)	Can increase the risk of ground instability in surrounding area

4.1.10. Fuel Cells

Fuel cells use chemical energy in fuels to produce electricity. A voltage difference between the cathode and anode of the cell is created through a chemical reaction between the fuel in the anode and oxygen in the cathode. This reaction generates heat, water, and a free electron. The free electron is then harnessed to generate an electrical current that can be converted into power. With hydrogen as the fuel source (a common fuel for fuel cells), the process is completely carbon free, making it a clean power source. Other fuels can be used to power the cell but will result in the generation of carbon dioxide. Electricity generation through chemistry rather than combustion allows fuel cells to achieve higher efficiencies compared with other power sources.

Currently, fuel cells have not been widely adopted as a source of power generation on a large scale and existing systems in operation are typically small in size. The technology is likely to gain wider acceptance in the future as global decarbonization commitments are pursued; however, the growth and implementation of fuel cells is significantly less than the growth of other renewable technologies, such as wind or solar PV. A challenge for hydrogen fuel cells is that the hydrogen has to be extracted from water via electrolysis or separated from carbon fossil fuels, which requires a significant amount of energy. For application to PEI, S&L considers that fuel cells might be considered for very small scale or demonstration projects on the island (perhaps to provide backup power to commercial or industrial buildings), but fuel cells are not well suited to provide substantial electrical generation capacity for the island.

Table 4-11 — Fuel Cell Advantages and Disadvantages

Fuel Cell Advantages	Fuels Cell Disadvantages
Renewable, clean energy source	Slow energy industry adoption rate
Dispatchable power plant	Projects are generally small in scale (i.e., a couple MWs or much less)
Highly efficient due to chemical generation	For hydrogen fuel cells, hydrogen has to be extracted separately through energy intensive electrolysis process.

4.2. FUELS CONSIDERED

A number of the different capacity resources generate electricity through the combustion of a fuel. Many of these resources are able to operate on a variety of different fuel types. The different fuel types explored for this analysis are listed below:

- Diesel
- Biodiesel
- Biomass
- Natural Gas and Compressed Natural Gas
- Hydrogen

Further discussion of the different fuels considered is provided in the following subsections.

4.2.1. Diesel

Diesel fuel is a commonly used fossil fuel that is produced from crude oil. As a fossil fuel, the burning of diesel fuel in thermal generators (i.e., engines or combustion turbines) releases carbon dioxide into the atmosphere. Ultra-low sulfur diesel fuel is currently used as the main fuel source for Maritime Electric's on-island backup generators. A benefit of diesel fuel is that there is a robust supply chain that makes it relatively easy to purchase. In addition, diesel fuel is easy to store for long periods of time (as opposed to many gaseous fuels like natural gas, hydrogen, etc.).

4.2.2. Biodiesel and Biomass

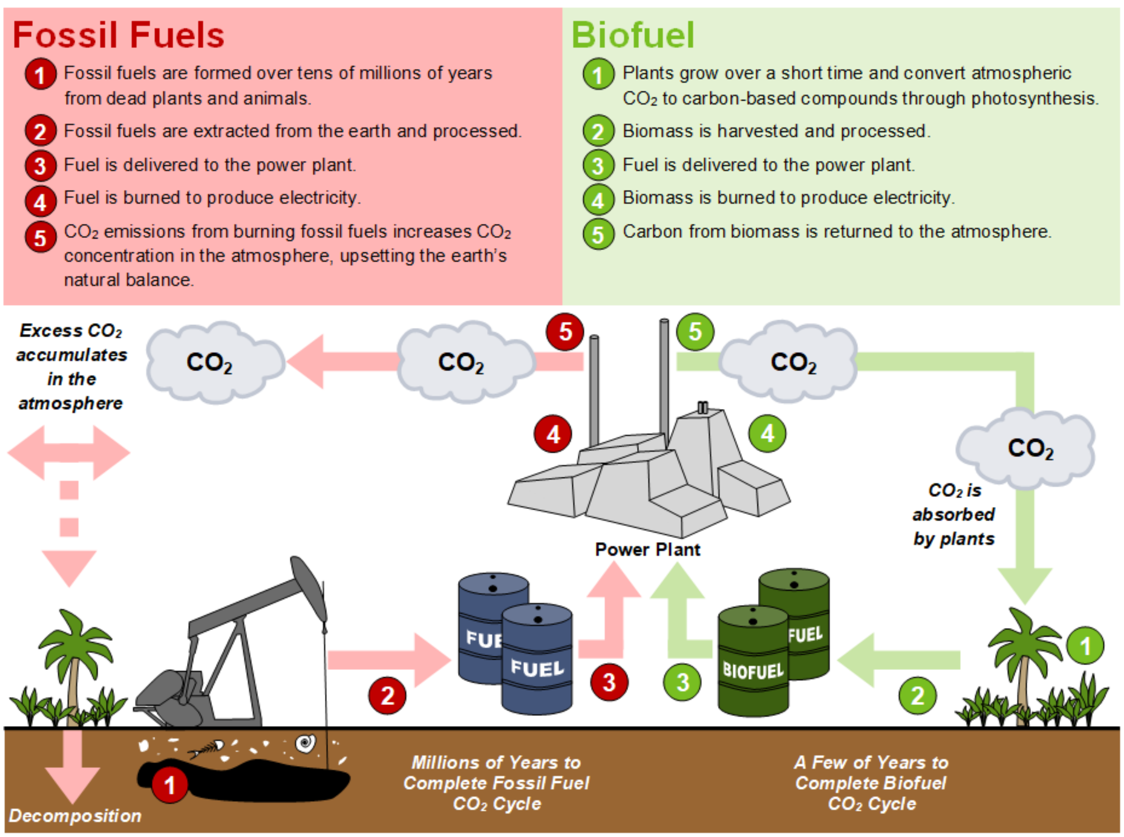
Biodiesel and biomass are both types of biofuel, which are produced from biological materials, rather than extracted from the earth like fossil fuels. Biofuels can be liquid, solid, or gas – biodiesel is a liquid fuel and biomass is a solid fuel. Although the combustion of biofuels releases carbon dioxide, when viewed from a life-cycle perspective, biofuels emit much lower greenhouse gas emissions than fossil fuels and may even result in zero net carbon emissions (discussed further below). Furthermore, biofuel-fired power generation facilities are dispatchable, meaning that they can be used at any time and at full capacity. The most applicable utility-scale applications of biofuels in PEI would be biodiesel and biomass. The government of Canada considers both biodiesel and biomass as renewable fuels[21].

An advantage of burning biofuels instead of fossil fuels is the reduction in life cycle carbon emissions. Life cycle emissions consider additions and reductions of carbon across the full cycle of biofuel production and consumption. Additions include the emissions associated with the combustion of the biofuel for electricity

[21] https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/renewable-energy/about-renewable-energy/7295

generation. Reductions occur as part of the earth's natural cycle associated with plant growth, as biomass growth removes carbon from the atmosphere through photosynthesis. Compared with traditional diesel, pure biodiesel (known as B100) reduces life-cycle carbon emissions by over 70%[22]. A 20% blend of biodiesel with traditional diesel (known as B20) would approximately reduce carbon emissions by 20% of this value, for a net reduction in carbon emissions of approximately 15% over traditional diesel. Solid biomass can also achieve at or close to carbon neutrality as long as the rate of re-planting/growth of the biomass keeps pace with the harvesting and consumption. The following figure provides an illustration of the carbon lifecycle differences between traditional fossil fuels and biofuels, such as biodiesel.

Figure 4-4 — Fossil Fuel vs. Biofuel Carbon Life Cycle



Biodiesel requires some special considerations when storing and utilizing as it can degrade various materials. Special attention must also be given to the fuel in the winter as it can gel if it is allowed to get too cold. Additionally, biodiesel degrades faster than traditional diesel – the typical shelf life for biodiesel that is properly stored is around 6 months.

[22] https://afdc.energy.gov/vehicles/diesels_emissions.html, https://www.anl.gov/argonne-scientific-publications/pub/140803

In this report, the potential use of biodiesel is considered for both reciprocating engines (RICE) and combustion turbines (CTs). Both generators are capable of firing biodiesel, up to a 100% blend (e.g., B100). Many of today's commercially available RICE units are already fully compatible with both traditional diesel and biodiesel firing, without requiring modification to the engine itself; however, some minor modifications would be required to the BOP and storage systems. CTs require some modifications to the various CT components to allow for biodiesel firing, such as compatible fuel injection nozzles, combustors, etc. These modifications are in addition to modifications to the CT BOP and storage systems (similar to what would be required for a RICE power plant). Once these modifications are made, the CT unit is able to burn either traditional diesel or biodiesel. We estimate the cost of the CT equipment modifications would be modest, in the CAD $2.5 million range, for a CT size in the 30 MW range.

Biomass is considered for biomass power plants. The type of biomass used in a power plant can vary from trees (typically wood pellets), grasses, or other sources. Equipment in a biomass power plant would need specialized design depending on the fuel type.

4.2.3. Natural Gas and Compressed Natural Gas

While natural gas is a common fuel utilized in the energy industry that releases much less carbon dioxide when burned than diesel fuel, the significant natural gas delivery infrastructure needed to support power generation (i.e., pipelines from the mainland, liquified natural gas delivery terminals, etc.) are not currently present on PEI. Furthermore, the costs associated with developing this infrastructure are too great to make economic sense for power plants that will be primarily utilized as backup generators. Compressed natural gas can be delivered by truck, but the amount of storage space required to utilize compressed natural gas at Maritime Electric's existing power plants (including required safe standoff distance) is too large for compressed natural gas to be utilized as a fuel source. For these reasons, both natural gas and compressed natural gas were not considered as fuel sources for this analysis.

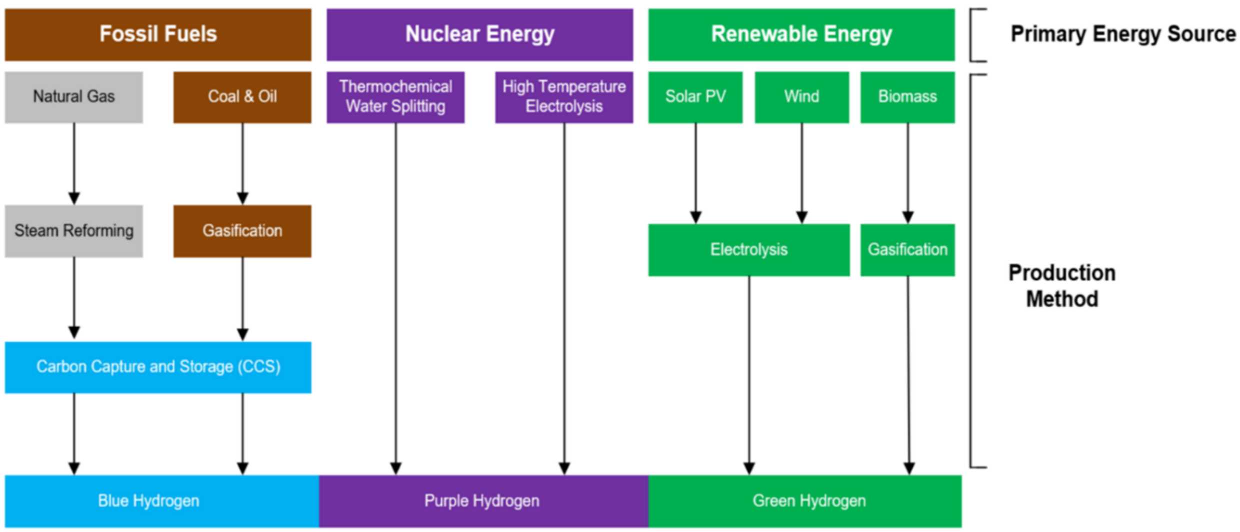
4.2.4. Hydrogen

Hydrogen is not considered as a fuel source for this analysis for a number of different reasons. Currently, there are not any commercially available RICE or CT resources that can operate on 100% hydrogen. The capability for RICE and CT generators to burn 100% hydrogen is estimated to be 5-10 years away based on our discussions with RICE and CT manufacturers. This section provides an overview of considerations associated with hydrogen's use in generators for informational purposes.

Hydrogen is an abundant element that can be stored and combusted to produce energy without carbon emissions. Currently, it has limited use in electricity generation; however, its high energy content per unit of weight and its near-zero emissions make it viable for greater use in the future. Challenges to widespread hydrogen usage include the need to separate elemental hydrogen from the compounds in which it naturally exists and the need for advanced storage and delivery methods. If these challenges can be effectively mitigated, hydrogen will see more significant usage for electricity generation in fuel cell applications or in conventional power plants.

Separation of elemental hydrogen from naturally occurring compounds like water is a process that requires energy. The predominant method for hydrogen production is steam reforming of natural gas, in which natural gas chemically reacts with water and heat to produce hydrogen and carbon dioxide. There are various other production methods, as shown in the following graphic.

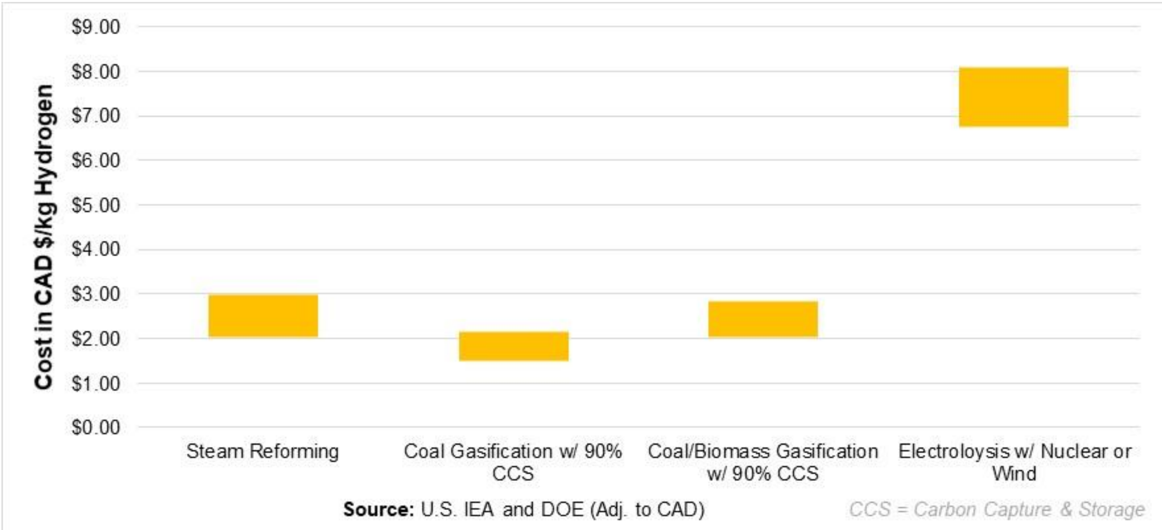
Figure 4-5 — Hydrogen Production Methods



At roughly CAD $1.5 to $3 per kilogram of hydrogen, gasification and steam reforming are currently the most economical ways to produce hydrogen, as illustrated by the following graphic. However, the projected cost of electrolysis is expected to decrease by 50% by 2030, bringing it more in line with the currently predominant and cost-effective methods[23].

[23] PEI has experience with a hydrogen electrolysis project through the Hydrogen Village project that was active in the 2005-2010 timeframe. It was determined at that time that electrolysis of hydrogen using wind power was uneconomic so the technology was not pursued.

Figure 4-6 — Current Cost of Hydrogen Production ($ CAD)



There is significant uncertainty as to the future pricing of hydrogen as a fuel source due to the fact that it is unknown how much both demand and supply might increase. Once elemental hydrogen is produced, it can be used in electricity generation applications in a variety of ways, including direct integration with an existing power plant. Introducing hydrogen as a fuel to an existing power plant requires a transportation and delivery method, which presents unique challenges due to hydrogen's extremely low boiling point temperature. Methods for hydrogen transportation are summarized below:

- **Pipeline**: Transporting gaseous hydrogen via existing pipelines is a low-cost option for delivering large volumes of hydrogen. The high initial capital costs of new pipeline construction constitute a major barrier to expanding hydrogen pipeline delivery infrastructure.
- **Truck – Liquid**: Hydrogen has the lowest boiling point of any element, requiring temperatures below -253°C for liquid phase. As a result, the maximum range for trucking is approximately 4,000 km because over the journey time the cryogenic hydrogen heats up, causing the pressure in the container to rise. Trucking liquid hydrogen is more economical than gaseous hydrogen trucking due to volume contained in truck.
- **Truck – Gas**: This method primarily is used for low / intermittent demand and existing power plant usage (for large generator cooling). Gaseous hydrogen is compressed to pressures of 180 bar (~2,600 psi gauge) or higher. Tube trailers pressure limitations can limit the amount of hydrogen that can be transported. Steel tube trailers are most common.

Once hydrogen is delivered to a site, it can be integrated into a power plant's primary fuel source. Most existing high-pressure transmission pipelines can accept up to 15% hydrogen blending (by volume) with their current material composition. This 15% hydrogen mixture can result in a 5% reduction in carbon dioxide (by mass) in combustion byproducts. Currently, gas turbine and engine manufacturers do not have commercially available generators that can burn 100% hydrogen; however, those are expected to be available within 5 years. OEMs have also indicated that many older, operating combustion turbines can accept some percentage of hydrogen mixed with natural gas.

Hydrogen integration is not without potential challenges and engineering considerations. For example, hydrogen is a smaller molecule than methane (a common fuel source), which means that gaskets and pipeline connections must be checked to eliminate leakage. Integration of hydrogen with an existing power plant can also cause material embrittlement, which can diminish load-bearing capacity and lead to cracking failures below the anticipated yield strength of susceptible materials. Hydrogen embrittlement affects base materials differently – it is problematic for high-strength steel but has no effect on austenitic stainless steel. Therefore, evaluation of welds must be performed prior to the introduction of hydrogen fuel due to welds' varying levels of hardness and yield strength.

Hydrogen usage in power plants also requires additional safety considerations. Hydrogen is the smallest molecule, enabling it to leak out of non-welded systems. It is also a colorless and odorless gas, causing leaks to be more difficult to detect. Furthermore, hydrogen is highly flammable and explosive even in low concentrations, and its temperature increases with pressure drops (in contrast to most other gases) due to the Joule–Thomson effect, increasing the risk of self-ignition during uncontrolled expansion. It therefore requires increased National Fire Protection Association classification and more stringent safety measures, which may require changes to existing electrical equipment and devices.

If Maritime Electric were to install a new generator, we do not recommend hydrogen be pursued as the primary fuel source at this point in time. Currently, engines or CTs that can combust 100% hydrogen are not yet commercially available; therefore, Maritime Electric would have to mix the hydrogen with natural gas. At present, there is not an established natural gas pipeline network on PEI; thus, Maritime Electric would also have to import and store natural gas on the island. Separately, since electricity purchased from NBEM is more economical than energy generated by the on-island CTs and engines, Maritime Electric's generators rarely operate. As a result, an investment into developing hydrogen storage infrastructure and supply chain would likely not result in a significant reduction in Maritime Electric's carbon emissions.

5. CAPACITY RESOURCE ANALYSIS

The different capacity resources considered in this report are analyzed in this section. The analysis first considers a high-level initial screening of the different technologies to rule out technologies that either do not have significant deployment in the energy industry or are clearly not well suited to be developed on PEI. Capacity resource technologies that pass the initial screening are further analyzed from a more in-depth perspective. This in-depth analysis includes a combination of technical, financial, and sustainability considerations. From the financial perspective, S&L has developed cost estimates of the short-listed capacity resource technologies based on our recent experience providing development oversight for projects of the respective technology. Cost estimates have been adjusted to account for PEI-specific considerations, including the island's location, construction labor estimates, taxes, etc.

5.1. INITIAL SCREENING OF TECHNOLOGIES

An initial screening process was performed to assess the high-level viability of the different capacity resource technologies considered in this report. This screening primarily looked at two different criteria:

1) **Significant Energy Industry Deployment**: This criterion is utilized to rule out technologies for which there would be a risk to Maritime Electric for being an early adopter of the technology. As an early adopter of a technology, Maritime Electric would potentially expose their customers to the financial risk associated with technology underperformance, high repair costs, design flaws, delays achieving commercial operation, and other associated items. As such, capacity resource technologies that do not have wide deployment in the energy industry are ruled out in the initial technology screening.

2) **Sufficient Renewable Resource**: This criterion is utilized to rule out renewable technologies for which there is not a sufficient renewable resource in PEI to support electricity generation.

The following table presents the results of the initial screening, including a set of notes regarding the screening decision. In order for the technologies to pass the initial screening, both criteria 1 and 2 must be met. Capacity resource technologies that pass the initial screening are considered as part of a more detailed analysis later in the report.

Table 5-1 — Initial Capacity Resource Technology Screening Results

Technology Type	Significant Energy Industry Deployment?	Sufficient Renewable Resource?	Notes / Other Considerations	Initial Screening Results
Onshore Wind Power	Yes	Yes	Widely used technology in energy industry, renewable technology	Selected
Offshore Wind Power	Yes	Yes	Widely used technology in energy industry, renewable technology	Selected
Solar PV (Utility Scale)	Yes	Yes	Widely used technology in energy industry, renewable technology	Selected
Rooftop Solar PV	Yes	Yes	Widely used technology in energy industry, renewable technology	Selected
Concentrating Solar Power (CSP)	Yes	No	Renewable technology, but PEI's direct normal irradiance levels are not high enough and PEI's climate is not ideal to support a CSP plant	Not Selected
Energy Storage (BESS, Li-Ion)	Yes	Not Applicable	Widely used technology in energy industry	Selected
Energy Storage (BESS, Flow)	No	Not Applicable	Technology has not gained widespread energy industry deployment to date	Not Selected
Energy Storage (Compressed Air)	No	Not Applicable	Only a handful of CAES facilities are in operation around the globe, relatively few are for output greater than 10 MW.	Not Selected
Reciprocating Internal Combustion Engine (RICE)	Yes	Not Applicable	Widely used technology in energy industry, can operate on various fuel types, including renewable-derived fuels	Selected
Combustion Turbine (CT) – Aeroderivative	Yes	Not Applicable	Widely used technology in energy industry, can operate on various fuel types, including renewable-derived fuels	Selected
Biomass Power Plant	Yes	Yes	Widely used technology in energy industry, flexibility to operate on various renewable-derived fuels, renewable technology	Selected
Nuclear - Small Modular Reactor (SMR)	No	Not Applicable	Technology has not yet gained widespread energy industry deployment to date	Not Selected
Tidal Power	No	No	Renewable technology, but only a handful of tidal power stations are in operation around the globe, PEI also lacks a significant tide	Not Selected
Wave Power	No	No	Renewable technology, but technology is in infancy with only a handful of very small-scale projects installed around the globe	Not Selected
Geothermal Power Plant	Yes	No	While widely used in energy industry, the best locations with sufficient heating resource are generally located in western Canada, renewable technology	Not Selected
Fuel Cell	No	Not Applicable	Currently, fuel cells are not yet a technology that has gained significant industry adoption for large power generation applications and existing systems tend to be small in size	Not Selected

5.2. CANDIDATES FOR SECONDARY SCREENING

The capacity resource technologies that passed the initial screening are listed below:

- Onshore wind power
- Offshore wind power
- Solar PV (utility scale)
- Rooftop solar PV
- Energy storage (BESS, Li-Ion)
- Reciprocating internal combustion engine
- Combustion turbine – aeroderivative
- Biomass power plant

The following subsections provide a detailed analysis and cost comparison of the different technologies. In addition, a discussion of how well the different technologies are able to help Maritime Electric cost-effectively meet its most important needs is also provided. These criteria are summarized below and also discussed in Section 2:

1) **Resource Contributions Towards Maritime Electric's Energy and Capacity Obligations:** Maritime Electric must meet both a) energy obligations and b) regional capacity obligations. Energy obligations are those associated with Maritime Electric meeting the system's electrical load every hour of the day. Maritime Electric's capacity obligations are the share of capacity that Maritime Electric must have either installed on-island or purchased from either on PEI or on the mainland such that the NPCC reliability standards for the Maritimes Area (which consists of PEI, New Brunswick, Nova Scotia, and northern Maine) are met.

2) **Resource Contributions When PEI is Electrically Disconnected from Mainland:** A scenario where PEI is electrically disconnected from the mainland is considered an emergency scenario with historical precedence. During this time, assets located on PEI alone must be able to meet load and stabilize the electrical system (electricity to stabilize the system is usually purchased from the mainland).

3) **Resource Contributions Towards Maritime Electric's Sustainability Targets:** Maritime Electric has established a greenhouse gas emissions reduction target to reduce emissions by 55% by 2030 (from 2019 levels). Preference should be given to resources that will help Maritime Electric achieve this target.

5.2.1. Wind Power

5.2.1.1. Onshore Wind Power

As discussed previously, consistent and strong wind speeds are one of PEI's best resources from a power generation perspective. The most recently installed wind farms on PEI approach a 50% capacity factor on an annual basis, which is among the highest in the energy industry for onshore wind farms. S&L developed a cost buildup for a 50 MW onshore wind power plant, which is provided in Appendix A. A summary of the costs is provided in the following table.

Table 5-2 — Onshore Wind Estimated Capital Costs, 50 MW

Cost Parameter	Estimated Cost ($ CAD)
Total Capital Costs	$106,280,000
Total Capital Costs ($/kW)	$2,126

Based on the high wind resource on PEI and the costs for wind power plants in comparison to other technologies, wind power is a cost-effective source of renewable generation for Maritime Electric. A separate cost buildup of operations and maintenance (O&M) costs is provided in Appendix B.

Resource Contributions Towards Maritime Electric's Energy and Capacity Obligations: Due to PEI's strong wind resource, the continued development of wind power plants on PEI is one of the most effective ways that Maritime Electric can meet its energy obligations in a carbon-free and cost-effective manner. The high capacity factors of the new wind power plants equate to large amounts of energy that are generated, providing carbon-free power to the community and offsetting imports from NBEM.

The intermittent nature of the wind means that wind power plants cannot contribute much towards Maritime Electric's regional capacity obligations. The reason for this is because Maritime Electric is required to calculate the capacity contributions of resources using a methodology that appropriately accounts for both the resource's intermittency and when the resource generates with respect to when system load is highest. The amount of wind capacity that Maritime Electric can count towards their capacity obligations is determined based on the wind power plant's effective load carrying capability (ELCC), which is discussed further in Appendix C. The ELCC for the 92.5 MW of wind generation in Maritime Electric's portfolio today is 23%, meaning that only 21 MW of the 92.5 MW of wind installed count towards Maritime Electric's capacity obligations (92.5 MW x 23% = 21 MW). The ELCC of a resource falls as more of that resource is installed (see Appendix C for further discussion). As a result, if Maritime Electric had another 70 MW of wind generation in their portfolio, for 162.5 MW of wind generation total, the ELCC for the portfolio is estimated to only be 17%. As a result, the resulting amount of wind capacity that Maritime Electric could count towards their capacity obligations would be 28 MW (162.5 MW x 17% = 28 MW), which is only a 7 MW increase in effective capacity over the current portfolio today.

Resource Contributions When PEI is Electrically Disconnected from Mainland: Given their intermittent nature, wind power plants are not a reliable source of electricity during a situation when PEI is electrically disconnected from the mainland. In the event that the wind power plants are generating electricity while PEI is disconnected, the on-island dispatchable generators will need to balance the wind generation so that there is not an over- or under-supply of electricity in the system (without proper balancing, the system can collapse)[24]. Typically, the balancing needs are met by NBEM using mainland-based generation, through the ties of PEI to the mainland. PEI has significantly more wind capacity installed on-island compared to installed dispatchable generating capacity, meaning that only a fraction of the wind capacity can be utilized when PEI is disconnected from the mainland, without risking the wind generation overwhelming the on-island dispatchable generators' balancing capabilities. During a disconnection of PEI, Maritime Electric estimates that only 37% of all the installed on-island wind nameplate capacity on PEI[25] could be utilized when all the on-island dispatchable generators are available. This value falls to 0% in the event the Charlottetown CT3 is unavailable.

Resource Contributions Towards Maritime Electric's Sustainability Targets: Wind energy is a great source of renewable carbon-free energy that would assist Maritime Electric in meeting their sustainability targets. Additional on-island wind generation will provide additional energy for Maritime Electric to serve load, resulting in less energy purchased from the mainland and therefore lower carbon emissions. Maritime Electric already has under contract a total of 92.5 MW of wind capacity that it utilizes to serve load, and an additional 70 MW of wind generation is planned. We estimate that the additional 70 MW of wind generation will decrease carbon emissions by approximately 14% on a tonnes CO_2e basis (see the "No BESS" column of Table 3-5).

[24] When generators are helping to "balance" the system, they must be operated at at less than their maximum output, which allows them to be able to absorb the fluctuations from load or intermittent generation (such as wind or solar) without causing system instability. RICE and CTs can operate as balancing generation as their output is controllable. Wind and solar are not dispatchable generators and thus cannot provide balancing services, since their output is generally not controllable. For reference, energy storage systems can help to balance the system; however, the amount an energy storage system can help balance the system when PEI is disconnected from the mainland may be limited since it depends on the state of charge of the BESS at the moment that disconnection occurs, the length of the disconnection, and whether/how much the wind power plants are generating electricity. This is discussed further in Section 5.2.3.

[25] This is based on energy from all wind generation located on-island, which includes facilities supplying both on- and off-island customers.

5.2.1.2. Offshore Wind Power

Offshore wind power plants generate energy in the same manner as onshore wind power plants, but they utilize larger turbines that are erected in the ocean and can generate more electricity with less intermittency (due to the more consistent winds over the ocean). While offshore wind power plants typically have a higher capacity factor than onshore wind power plants, PEI's onshore wind resource is very strong both in terms of wind speed and frequency. As a result, the expected improvement in capacity factor for offshore turbines near PEI versus PEI's onshore turbines will likely be modest.

From a capital cost perspective, offshore wind power plants are significantly more expensive than onshore wind power plants due to the challenges associated with developing the power plants and their associated infrastructure in the ocean. Based on information we maintain in our internal project databases, we estimate that an offshore wind power plant would cost 3x to 4x more than an onshore wind power plant on a dollar per kW basis ($6,000/kW - $8,000/kW), or potentially more. Additionally, offshore wind power plants are typically hundreds to thousands of MWs in size, which allows them to capture economies of scale cost efficiencies. Given the relatively small amount of generation that Maritime Electric has to serve, an offshore wind power plant likely does not make sense for Maritime Electric's small system.

In summary, given the strong onshore wind resource on PEI and the significantly lower costs associated with onshore wind as compared to offshore wind, an offshore wind power plant is not a recommended resource solution for Maritime Electric.

5.2.2. Solar PV

5.2.2.1. Utility-Scale Solar PV

While PEI's northern latitude and climate are not ideal for solar PV generation, the solar resource on PEI is still high enough to provide a limited amount of energy to the island. As shown in Appendix D of this report, the expected capacity factor for a solar PV power plant on PEI is approximately 19.9% for a bifacial, fixed-tilt configuration. The following table presents our expected costs for 50 MW of solar PV built on PEI (5x10 MW power plants, bifacial, fixed-tilt configuration). The costs are based on our project experience within Canada and the northeastern United States. It is important to note that the costs in the table below are marginally higher than those expected for an onshore wind power plant on PEI with a similar nameplate capacity; however, the expected annual generation produced by the solar PV power plant is less than half of that expected for an onshore wind power plant. A separate cost buildup of O&M costs is provided in Appendix B.

Table 5-3 — Utility Scale Solar PV Estimated Capital Costs, 50 MW (5x10 MW)

Cost Parameter	Estimated Cost ($ CAD)
Total Capital Costs	$119,474,000
Total Capital Costs ($/kW)	$2,389

Resource Contributions Towards Maritime Electric's Energy and Capacity Obligations: A solar PV power plant would help Maritime Electric meet its energy obligations and purchase less energy from NBEM. While the solar resource on PEI is much lower than the wind resource on PEI, the addition of solar energy to Maritime Electric's generation portfolio would provide diversification since the solar and the wind generation profiles would not be perfectly correlated. In general, a more diverse generation portfolio is beneficial since different resources can complement one another – for example, solar PV can still generate electricity during the day when the wind might not be blowing. However, given the fact that the expected capacity factor of solar PV is much lower than that of an onshore wind power plant for a similar dollar per kW cost point, PEI and Maritime Electric would have to determine if those diversification benefits are high enough to justify investment in solar PV versus simply continuing to invest in more onshore wind power plants, which provide a much higher amount of MWhs generated per dollar invested.

Since the solar PV generates only during the daytime hours, it is unable to supply energy in winter evening periods when Maritime Electric typically reaches its annual peak load. As a result, the ELCC of solar PV is zero, meaning solar PV would not be able to contribute to Maritime Electric's regional capacity obligations.

S&L recommends that continued investment into wind power plants on PEI be pursued as the first priority, with investment into utility-scale solar PV pursued as a close second priority.

Resource Contributions When PEI is Electrically Disconnected from Mainland: Similar to wind, solar PV is limited in the amount of energy that it can contribute in the event of a disconnection of PEI from the mainland. The intermittent nature of the solar generation will require balancing from the on-island dispatchable generators. Additionally, solar PV will not generate energy at night and generation will be reduced when there is cloud cover, further limiting the amount of electricity the resource can provide during a disconnection event. As a result, solar PV power plants are not a reliable resource for Maritime Electric in the event that PEI is disconnected from the mainland.

Resource Contributions Towards Maritime Electric's Sustainability Targets: As a renewable resource, solar PV will support Maritime Electric's efforts towards reducing carbon emissions. Any generation from a solar PV power plant will equate to less energy needed to be purchased from mainland power plants (some of which emit carbon) through the contract with NBEM.

5.2.2.2. Rooftop Solar PV

Small-scale solar PV is typically installed by a customer on the roof of their building (in a small number of cases it is installed as a standalone unit on a customer's property). Customers that install rooftop solar are still connected to the grid, allowing them the ability to buy electricity when their rooftop solar PV production may not be high enough to fully meet their electrical load. Likewise, the connection of the rooftop solar PV system to the grid allows the customer to sell any excess generation back to Maritime Electric. Typically, rooftop solar PV systems are sized to fully offset the home's/business' electrical consumption. The net effect of rooftop solar PV growth on PEI is that it decreases the amount of electricity Maritime Electric needs to provide to their customers, which equates to less electricity purchases from NBEM and thus lower carbon emissions.

S&L has calculated the estimated cost for a 10-kW rooftop solar PV system, including the total cost per kW installed. A summary of those costs is provided in the table below, with a more detailed buildup of costs provided in Appendix A.

Table 5-4 — Rooftop Solar PV Estimated Capital Costs (10 kW)

Cost Parameter	Estimated Cost ($ CAD)
Total Capital Costs (after rebate)	$31,310
Total Capital Costs ($/kW) (after rebate)	$3,131

While less cost effective than utility scale solar PV, rooftop solar PV can be economical for customers, when supported with governmental grants and incentives, from the perspective that it is a long-term investment. Additionally, there are intrinsic benefits for individuals that install rooftop PV systems on their homes/businesses associated with reducing one's carbon footprint.

For much of North America, including PEI, utilities compensate customers that install rooftop solar through a mechanism called net metering. In a net metering arrangement, any electricity that a homeowner / business generates is credited on their electricity bill, often at a fixed electricity rate. If the solar system produces excess electricity beyond the homeowner / business' load, the excess generation is injected back into the electric system and credited on a future electricity bill. There are some drawbacks associated with net metering that are worth noting. First, the value of electricity varies by the time of day, based on system supply and demand. As such, crediting a fixed electricity rate through a net metering program can mis-align 1) the actual value the solar energy provides to the electrical system to 2) what the utility pays the customer for the solar energy. Additionally, electricity rates pay for other services beyond simply the cost to generate the electricity, including costs to maintain/improve the transmission and distribution system, costs for the utility to meet regional capacity obligations, etc. A net metering program can unfairly shift the costs for these services away from customers that have net-metered solar systems onto customers that do not have solar systems. It is generally found that the societal benefits of rooftop solar outweigh these costs; however, it might be beneficial for Maritime Electric to explore if there are alternative payment mechanisms that can be employed to more equitably share the costs associated with rooftop solar.

Resource Contributions Towards Maritime Electric's Energy and Capacity Obligations: The continued growth of rooftop solar PV on PEI contributes to Maritime Electric's ability to meet energy obligations by reducing system electrical load throughout the daytime. Since rooftop solar PV generation does not occur in the evening (when system load is highest), total system load in the evening is likely to be unchanged. As a result, Maritime Electric's capacity obligations are not likely to fall as more rooftop solar PV is adopted.

Resource Contributions When PEI is Electrically Disconnected from Mainland: With widespread adoption of rooftop solar PV on PEI, the resource could provide a positive systemwide impact during times when PEI is disconnected from the mainland via system load reductions in the daytime. Currently, there is not enough rooftop solar PV installed on PEI to make an appreciable system-wide difference. Additionally, during the night or when there is significant cloud cover, rooftop solar PV will not be able to contribute to the system. Thus, rooftop solar PV is not currently a reliable resource that allows Maritime Electric to better navigate a disconnection to the mainland.

Resource Contributions Towards Maritime Electric's Sustainability Targets: As a renewable resource, rooftop solar PV will support Maritime Electric's efforts towards reducing carbon emissions. Any generation from a rooftop solar PV system will equate to less electricity that Maritime Electric needs to purchase from NBEM.

5.2.3. Lithium-Ion Energy Storage

Lithium-ion energy storage is the most common BESS in the energy industry. BESS is not a generation resource, it is a storage resource that can transfer energy from one time to another; however, many of the use cases for BESS overlap with those of generators. In addition, the unique technical characteristics of BESS allow it to be used in ways many generator types are unable. For example, BESS' ability to inject energy instantaneously makes it well suited to perform energy arbitrage through an energy marketplace (i.e., charging when energy prices are low and discharging when energy prices are high), ancillary services (i.e., voltage support, frequency regulations, etc.), and other similar use cases requiring fast response. This section highlights how BESS can contribute to the three specific use cases that are most critical to Maritime Electric at this point in time.

S&L has provided technical and project developmental guidance to numerous BESS projects. In addition, we have helped run numerous requests for proposals (RFPs) on behalf of utilities for generation and storage projects. As such, we have a detailed cost database of current BESS project pricing. The following table provides our estimate of the capital cost summary for a 50 MW BESS project developed on PEI for three different storage durations: 1 hour, 2 hours, and 4 hours. A more detailed cost buildup of storage costs is provided in Appendix A, including 8 hour and 24 hour duration projects.

Table 5-5 — Lithium-Ion Energy Storage (50 MW) Estimated Capital Costs

BESS Size	Cost Parameter	Estimated Cost ($ CAD)
50 MW, 50 MWh (1-hr storage)	Total Capital Costs	$47,966,000
	Total Capital Costs ($/kW)	$959
	Total Capital Costs ($/kWh)	$959
50 MW, 100 MWh (2-hr storage)	Total Capital Costs	$78,228,000
	Total Capital Costs ($/kW)	$1,565
	Total Capital Costs ($/kWh)	$782
50 MW, 200 MWh (4-hr storage)	Total Capital Costs	$133,523,000
	Total Capital Costs ($/kW)	$2,670
	Total Capital Costs ($/kWh)	$668

It is important to note that while BESS project pricing has fallen continuously over the last decade, prices are still relatively more expensive than some similarly sized generators that can be used for similar use cases, specifically engines and combustion turbines. In recent years, supply chain constraints associated with the demand for electronics and lithium have contributed to BESS prices not being able to achieve full price parity with these generator types.

For comparison, the O&M costs for a new 50 MW, 4-hour, BESS project are estimated to be similar to the O&M costs for an equally-sized new RICE unit that would serve primarily as a backup generator for Maritime Electric (see the end of Appendix B for a detailed 20-year comparison of O&M costs for both BESS and RICE). Considering that a BESS project would likely be utilized more frequently on a day-to-day basis than a backup RICE generator, the BESS O&M costs are considered to be relatively inexpensive. However, due to the performance degradation of batteries with usage, Maritime Electric would have to augment the BESS project (i.e., add more battery cells) multiple times over the project's service life in order to keep the BESS at a consistent performance level. The costs of augmentations are sizable – augmentations are estimated to cost a total of nearly CAD $20 million (2022 $'s) over a 20-year BESS project life (see the table at the end of Appendix B for additional details) for a 50 MW, 4-hour project. It is important to note that a BESS project does not have to be augmented; however, a typical non-augmented project can be expected to degrade approximately 25% to 30% over a 20-year lifespan.

Resource Contributions Towards Maritime Electric's Energy and Capacity Obligations: A BESS project will have a limited ability to help Maritime Electric meet its energy obligations. This is due to the fact that as a storage resource, a BESS can only store and re-inject already generated electricity. As discussed in detail in Section 3.2.1, in the event that generation from the wind power plants on PEI (and any future solar power plants) plus the nuclear generation from Point Lepreau results in an excess of generation above system load, Maritime Electric has to sell the excess generation to the mainland. During these times, a BESS project would be able to store some or all of this excess generation and re-inject it later, which would help Maritime Electric better meet its energy obligations. Currently, the vast majority of the electricity generated by the wind power plants on PEI is used immediately to serve load – times when there is excess generation are extremely rare. With additional wind and solar projects planned for PEI, specifically the additional 70 MW of wind planned to be online in the coming years, the amount of times when there will be excess generation is likely to increase, but not to forecasted levels that justify a significant investment in BESS. As such, a BESS project is unlikely to appreciably help Maritime Electric meet its energy obligations in the near to intermediate future.

From the perspective of capacity obligations, a significant portion of a BESS' nameplate capacity would be able to be used by Maritime Electric to meet its regional capacity obligations. The exact amount would need to be quantified and would vary based on the technical characteristics of the BESS project, but we expect that it is likely to be similar to the BESS' nameplate capacity. As such, a BESS project is an excellent resource to help Maritime Electric meet its regional capacity obligations if the BESS is used primarily for capacity storage.

Resource Contributions When PEI is Electrically Disconnected from Mainland: During a disconnection event, a BESS could be able to provide some benefit to the island, but the amount is likely to be limited. If PEI is disconnected from the mainland, Maritime Electric does not currently have enough generation to meet system load. As a result, rolling blackouts are expected (discussed further in Section 2.2.2). The addition of BESS to PEI could help Maritime Electric to better balance the wind generation intermittency during a disconnection from the mainland, which would in turn allow Maritime Electric to utilize more of PEI's wind capacity to serve system load. This would likely equate to less severe rolling blackouts.

The level at which BESS would be able to help the system during a disconnection of PEI from the mainland depends on a number of factors, including the state of charge of the BESS at the moment the disconnection occurs, the length of the disconnection, and whether / how much the wind power plants are generating electricity. At best, a BESS system could be very helpful for Maritime Electric during a disconnection from the mainland; however, if the wind power plants are not generating electricity during the time when PEI is disconnected from the mainland, then the amount of support a BESS could provide is limited to both its state of charge and duration. As a result, there is significant uncertainty around how much a BESS project would be able to support the system during a disconnection from the mainland, and thus a BESS project is not considered to be a reliable resource for this specific use case.

Resource Contributions Towards Maritime Electric's Sustainability Targets: In the event that generation from the wind power plants on PEI (and any future solar power plants) plus generation from Point Lepreau results in an excess of generation above system load, Maritime Electric has to sell this excess generation to the mainland. During these times, a BESS project would be able to store some or all of the excess generation and re-inject it on PEI later, which would allow Maritime Electric to purchase less total energy from NBEM and thus reduce carbon emissions. As shown in Section 3.2.1, there is currently not enough wind capacity installed on PEI today, or additional wind capacity planned in the intermediate future (specifically the additional 70 MW of wind planned in the coming years), to result in a large number of times when there will be excess generation above load. As a result, the installation of a BESS is not expected to appreciably improve Maritime Electric's ability to meet sustainability targets in the near future.

As more wind is installed on PEI beyond the 70 MW planned for the coming years, there will be more times when there is excess generation above load. As a result, a BESS would be able to better help Maritime Electric meet sustainability goals; however, at that point in time we recommend that a comparative assessment be performed to assess various carbon-reduction solutions, including a BESS, to determine which solutions would provide the highest carbon-reduction benefits on a per dollar invested perspective.

5.2.4. Reciprocating Internal Combustion Engine

A RICE is a type of dispatchable generator that can provide both energy and capacity. A RICE is a common resource in the energy industry due to its modularity, flexibility (ability to start/stop and ramp quickly), and cost-effectiveness. Additionally, a RICE can operate on a variety of different fuels, including renewable fuels such as biodiesel. While commercially-available RICE offerings cannot yet operate on 100% hydrogen, engine manufacturers expect to have this capability in the coming years. For the purposes of Maritime Electric, the ability for a RICE power plant to operate on renewable fuels would help to reduce the risk that a new RICE power plant might become a stranded asset should the Canadian government introduce stricter policies regarding allowable fuels that can be used for power generation. Maritime Electric would utilize a new RICE power plant primarily for backup and emergency generation.

The following table provides a summary of the expected capital costs for new RICE power plant, specifically one operating on diesel fuel and another operating on biodiesel fuel. A more detailed cost buildup of RICE costs is provided in Appendix A. For reference, two differently designed RICE power plants are not needed to be able to operate on either diesel fuel or biofuel. Engines are very flexible in terms of fuel type; thus, the same power plant could switch from burning diesel fuel to biodiesel fuel without modification. The difference in per kW cost are primarily because the operation of RICE power plant on biodiesel results in some derating in output versus operation on traditional diesel fuel. A separate cost buildup of O&M costs is provided in Appendix B.

Table 5-6 — Reciprocating Internal Combustion Engine Estimated Capital Costs

RICE Unit [1]	Cost Parameter	Estimated Cost ($ CAD)
5 x RICE Units, 53 MW Total, Diesel Fuel	Total Capital Costs	$119,657,000
	Total Capital Costs ($/kW) [2]	$2,257
5 x RICE Units, 46.7 MW Total, Biodiesel Fuel	Total Capital Costs	$119,729,000
	Total Capital Costs ($/kW) [2]	$2,556

Notes

1) Wärtsilä 20V32 engines are assumed as representative engine types. Other manufacturers make similar engines to this model.
2) While the engine type and size are consistent with both diesel and biodiesel fuel, the use of biodiesel results in some derating of engine output versus diesel fuel; thus, the capital costs on a $/kW basis are different.

Resource Contributions Towards Maritime Electric's Energy and Capacity Obligations: From the perspective of energy obligations, Maritime Electric would use a RICE primarily as a back-up generator and dispatch only when enough electricity could not be procured from the mainland, or during emergencies. As such, it is not expected that a RICE will be utilized to meet Maritime Electric's energy obligations; however, given that a RICE is a dispatchable generator, it could be utilized to meet Maritime Electric's energy obligations if called upon.

A RICE would provide capacity to help Maritime Electric meet its regional capacity obligations. If installed, close to the RICE's nameplate capacity could be utilized to meet Maritime Electric's capacity obligations. A RICE power plant is an excellent source of generating capacity.

Resource Contributions When PEI is Electrically Disconnected from Mainland: A RICE would be a very beneficial resource for Maritime Electric in terms of being able to provide generation to the grid in the event of an electrical disconnection of PEI from the mainland. The addition of a RICE to PEI would provide Maritime Electric more dispatchable capacity to both serve load and also to balance the wind generation intermittency during a disconnection, which would in turn allow Maritime Electric to utilize more of PEI's wind capacity without risking an imbalance of generation and load. As a result, a RICE would reduce the severity of a rolling blackout situation if PEI were disconnected from the mainland.

Resource Contributions Towards Maritime Electric's Sustainability Targets: As primarily a backup generator, an additional RICE would have a small impact on Maritime Electric's overall carbon emissions (this is further illustrated in Table 3-3); however, a RICE does produce carbon emissions when burning fuel.

The amount of carbon emissions the RICE generates is dependent on the type of fuel the RICE burns. Based on PEI's existing fuel delivery infrastructure, the two fuels that are the most realistic for use by Maritime Electric in a RICE are diesel and biodiesel fuel. As a fossil fuel, traditional diesel produces carbon emissions when burned. Biodiesel combustion also produces carbon emissions; however, the lifecycle emissions (considering net emissions from the entire production process of the fuel) of biodiesel are much lower than typical diesel fuel. In fact, the lifecycle emissions are low enough that the government of Canada considers biodiesel a renewable fuel[26].

5.2.5. Combustion Turbine – Aeroderivative

Aeroderivative CTs have many similarities to RICE in terms of the benefits they can provide to an electrical system. CTs are a dispatchable generating resources that are flexible (i.e., they can start/stop and ramp quickly), cost effective, and very common in the energy industry. CTs are also flexible in that they can operate on a variety of different fuels, including both diesel and biodiesel fuels. For the purposes of Maritime Electric, the fuel flexibility of CTs helps to reduce the risk that they might become a stranded asset if the Canadian government introduced stricter restrictions on what fuels could be used in power plants. Unlike RICE, aeroderivative CTs require some minor modifications and associated capital investment to be able operate on biodiesel (estimated at around CAD $2.5 million for a 30 MW CT). Maritime Electric would primarily utilize a CT to provide backup generation and also generation during emergencies.

The following table provides a summary of the expected capital costs for a new aeroderivative CT power plant, specifically ones operating on diesel fuel and another operating on biodiesel fuel. A more detailed cost buildup of CT costs is provided in Appendix A. A separate cost buildup of O&M costs is provided in Appendix B.

Table 5-7 — Combustion Turbine Estimated Capital Costs

RICE Unit	Cost Parameter	Estimated Cost ($ CAD)
2 x Aeroderivative CTs, 58 MW Total, Diesel Fuel	Total Capital Costs	$144,530,000
	Total Capital Costs ($/kW)	$2,486
2 x Aeroderivative CTs, 58 MW Total, Biodiesel Fuel	Total Capital Costs	$153,692,000
	Total Capital Costs ($/kW)	$2,643

Notes

1) General Electric LM2500+ are assumed as representative CT types. Other manufacturers make similar CTs to this model.
2) While the CT type and size are consistent with both diesel and biodiesel fuel, the use of biodiesel necessitates additional capital costs to modify some CT combustion / fuel delivery equipment

[26] https://www.nrcan.gc.ca/energy-efficiency/transportation-alternative-fuels/alternative-fuels/biofuels/biodiesel/3509

Resource Contributions Towards Maritime Electric's Energy and Capacity Obligations: An aeroderivative CT power plant would primarily be utilized by Maritime Electric as a backup generator. As a result, a new CT power plant would likely not contribute appreciably towards helping Maritime Electric meet its energy obligations; however, given that it is a dispatchable generator, it could generate energy if called upon.

A CT would help Maritime Electric meet its regional capacity obligations. If installed, close to the CT's nameplate capacity could be utilized to meet Maritime Electric's capacity obligations. A CT power plant is an excellent source of generating capacity.

Resource Contributions When PEI is Electrically Disconnected from Mainland: Similar to a RICE, a CT power plant would be a very beneficial resource for Maritime Electric in terms of being able to provide generation to the grid in the event of an electrical disconnection of PEI from the mainland. The addition of a CT to PEI would provide Maritime Electric more dispatchable capacity to both serve load and also to balance the wind generation intermittency during a disconnection, which would in turn allow Maritime Electric to utilize more of PEI's wind capacity without risking an imbalance of generation and load. As a result, a CT power plant would reduce the severity of a rolling blackout situation if PEI were disconnected from the mainland.

Resource Contributions Towards Maritime Electric's Sustainability Targets: Similar to a RICE power plant, a CT power plant would primarily be utilized to provide system backup generating capacity and support for the system during an emergency. As a result, a CT power plant would have a small impact on Maritime Electric's overall carbon emissions (this is further illustrated in Table 3-3); however, a CT does produce carbon emissions when burning fuel. The amount of carbon emissions generated by a CT power plant is dependent on the type of fuel burned. As a fossil fuel, regular diesel produces carbon emissions when burned. Biodiesel combustion also produces carbon emissions; however, the lifecycle emissions (considering net emissions from the entire production process of the fuel) of biodiesel are much lower than typical diesel fuel (the Canadian government considers biodiesel to be a renewable fuel).

5.2.6. Biomass Power Plant

Biomass power plants are both dispatchable and renewable. Biomass power plants burn biomass fuel to create steam, which drives a steam turbine to produce electricity. Biomass power plants are less flexible than other generating technologies in that a biomass power plant will take longer to start/ramp to different generation levels than a RICE or CT power plant, or BESS project. In addition, biomass power plants are generally more expensive to build than other generating technologies due to the complexity associated with the different systems/equipment (i.e., steam generation, feedwater, steam piping, steam turbine, etc.). Due to its relative inflexibility and high capital cost, it generally makes more sense to operate a biomass power plant as a baseload generator rather than as a backup generator.

An estimate of capital costs to build a 50 MW biomass power plant is provided below. These costs are developed based on our experience with biomass, boilers, steam turbines, and other related equipment.

Table 5-8 — Biomass Power Plant Estimated Capital Costs, 50 MW

Cost Parameter	Estimated Cost ($ CAD)
Total Capital Costs	$292,803,000
Total Capital Costs ($/kW)	$5,856

Resource Contributions Towards Maritime Electric's Energy and Capacity Obligations: A biomass power plant can help Maritime Electric meet both of its energy and capacity obligations. In addition, as a dispatchable generator, Maritime Electric would have control over the dispatch of the power plant. Due to its operational inflexibility, a biomass power plant would likely have to serve as a baseload generator for Maritime Electric. From a cost perspective, while a biomass power plant is also a renewable resource, it is much more expensive than other renewable resources such as onshore wind and solar PV.

Resource Contributions When PEI is Electrically Disconnected from Mainland: As a dispatchable resource, a biomass power plant would be well suited to provide power during an event where PEI is electrically disconnected from the mainland. While a biomass power plant could provide generation, it would be less effective at providing renewable/load balancing support than other generator technologies (i.e., RICE or CTs) or BESS projects. This is due to the fact that a biomass power plant is not as flexible as other technologies in terms of its ability to quickly ramp to different generation levels.

Resource Contributions Towards Maritime Electric's Sustainability Targets: As a renewable generator, a biomass plant would help contribute towards Maritime Electric meeting their sustainability targets. The Canadian government recognizes biomass plants as renewable resources if the complete fuel cycle (i.e., growth of the biomass through combustion in the generators) is carbon net zero. When burned, biomass fuel does emit carbon, but this carbon is considered to be consumed during the process of growing more biomass. One challenge with a biomass power plant is that a significant amount of land would be required to grow the biomass required to fuel the power plant, and to reduce transportation of fuel, having the biomass near the facility is beneficial. An adequate source of biomass on PEI would have to be identified, or a fuel sourcing analysis would be required to see if it can be sourced from the nearby mainland.

5.2.7. Technology Comparison and Final Selection

Based on the analysis in this section, two technologies do not pass the secondary screening: offshore wind and biomass. The following bullets highlight the reasons for these technologies not being selected.

- **Offshore Wind Power Plant**: This resource does not pass the secondary screening for a number of reasons. First, an offshore wind farm off the coast of PEI is only going to be able to achieve a performance level that is incrementally better than an onshore wind farm on PEI. The reason for this is because PEI's onshore wind resource is already very high. Secondly, the cost of offshore wind is an order of magnitude higher than onshore wind. Additionally, offshore wind power plants are typically hundreds to thousands of MWs in size, which allows them to capture economies of scale cost efficiencies. This is much larger than Maritime Electric's needs. Based on these two reasons, offshore wind is not selected to pass the secondary screening.
- **Biomass Power Plant**: This resource does not pass the secondary screening primarily as a result of both its high capital cost and the large land requirements to grow the solid biomass fuel. We estimate that a biomass power plant would cost approximately 2.8 times the cost of a similarly sized onshore wind farm and 2.6 times the cost of a similarly sized RICE power plant on PEI. Those higher costs do not equate to nearly the same level of additional value a biomass power plant would provide in terms of helping Maritime Electric meet its most critical needs. Additionally, the land requirements to grow the required biomass to fuel the power plant are very high. While it is unknown exactly how much land would be required since this would depend on the type of fuel utilized and where it is sourced from, it could easily stretch from 5,000 to 10,000 acres once one accounts for the fact that harvested biomass needs to be replanted and given time to grow (which can take years/decades) before it can be re-harvested again. As a result of both of these reasons, a biomass power plant is not selected to pass the secondary screening .

The remaining technologies pass the secondary screening and move on to the final screening, discussed in the following section. The following table is developed to help compare the various shortlisted technologies. The table combines both the cost of the resource and also the various key attributes of the different evaluated technologies with respect to the three evaluation criterion: 1) the resource's ability to contribute to Maritime Electric's energy and capacity obligations, 2) the resources ability to support the electrical system when PEI is disconnected from mainland, and 3) the resource's ability to help Maritime Electric achieve its sustainability targets. The table is color coded either green or red. Green technologies are those that are selected to pass the secondary screening. Red technologies do not pass the secondary screening.

Table 5-9 — Comparison of Various Shortlisted Resources

Resource	Estimated Overnight Capital Cost ($CAD/kW)	Contributions to Energy and Capacity Obligations	Contributions When PEI is Disconnected from Mainland	Contributions to Sustainability Targets
Onshore Wind Power	$2,126 / kW	*Energy:* Excellent, but intermittent. High expected power plant capacity factor. *Capacity:* Poor, low ELCC	Unreliable resource – Can provide energy during a disconnection, but generation is intermittent. Generation intermittency/variability needs to be balanced by another resource.	Excellent – Renewable generator, very strong wind resource on PEI
Offshore Wind Power	$6,000+ / kW	Similar to onshore wind.	Similar to onshore wind	Similar to onshore wind
Utility-Scale Solar PV	$2,389 / kW	*Energy:* Good, but intermittent. Average expected power plant capacity factor. *Capacity:* Poor, low ELCC	Unreliable resource – Can provide energy during a disconnection, but generation is intermittent. Generation intermittency/variability needs to be balanced by another resource.	Good – Renewable generator, but just average solar resource on PEI
Rooftop Solar PV	$3,131 / kW	Similar to utility-scale solar PV.	Similar to utility-scale solar PV	Similar to utility-scale solar PV
Lithium-Ion BESS	*50 MW, 1-hr* $959 / kW ($959 / kWh) *50 MW, 2-hr* $1,565 / kW ($782 / kWh) *50 MW, 4-hr* $2,670 / kW ($668 / kWh)	*Energy:* Limited – BESS can time-shift previously generated electricity. Also, there are rarely times currently or expected in the intermediate future when there is/will be excess wind + nuclear generation above system load that could be time-shifted to other hours. *Capacity:* Excellent resource	Uncertain / depends on event – A BESS' ability to contribute to the system (both serving load and providing renewable/load balancing) during a disconnection is dependent on the BESS state of charge when the event occurs, the length of the event, and the operation/output of the wind farms. These variables are either partially or completely out of Maritime Electric's control. At best, a BESS could significantly support the system, at worst, it would not be able to provide support.	Limited – There are rarely times currently or expected in the intermediate future when there is/will be excess wind + nuclear generation above system load that could be time-shifted to other hours. As such, BESS would not appreciably improve Maritime Electric's ability to achieve its sustainability targets. BESS' contributions will increase as more renewable generation is added to the island.
Reciprocating Engines	*Diesel* $2,257 / kW *Biodiesel* $2,556 / kW	*Energy:* Limited – RICE would likely serve as a backup generator and would be rarely utilized to meet energy obligations; however, it could generate electricity if needed. *Capacity:* Excellent resource	Excellent – As a dispatchable generator with quick start and ramping capabilities, RICE power plants are ideal to help Maritime Electric support the system in a disconnection scenario. Due to its operational flexibility, a RICE power plant could both serve load and provide renewable/load balancing.	Limited – Since a RICE power plant would be primarily a backup facility, the impact to total Maritime Electric emissions would be small. Also, depending on the fuel utilized (diesel vs. biodiesel), RICE could have either a small negative or small positive impact from a carbon emissions perspective.
Combustion Turbines	*Diesel* $2,486 / kW *Biodiesel* $2,643 / kW	Similar to RICE (see above)	Similar to RICE (see above)	Similar to RICE (see above)
Biomass Power Plant	$5,856 / kW	*Energy:* Excellent (would likely have to serve as a baseload generator though) *Capacity:* Excellent	Good – As a dispatchable generator, a biomass plant would be able to provide electricity to the system during a disconnection. However, due to its operational inflexibility, it is not an ideal resource to provide renewable/load balancing.	Good – While a biomass power is considered renewable, the very large land and deforestation/harvesting requirements needed to fuel the power plant are not ideal.

6. CAPACITY RESOURCE RECOMMENDATIONS

6.1. FINAL TECHNOLOGY SELECTIONS

The following generation / storage technologies passed the secondary screening and are further analyzed in this section for potential recommendation for Maritime Electric.

- Onshore wind generation
- Utility-scale solar PV
- Rooftop solar PV generation
- Energy storage, lithium ion
- Reciprocating engine, with biofuel combustion compatibility
- Combustion turbine, with biofuel combustion compatibility

Given the above technologies each have unique characteristics and would serve different purposes for Maritime Electric, the greatest benefit to the electrical system is likely to be achieved using a combination of the above technologies. As such, different portfolios including the above technologies are defined and assessed in this section. Specifically, the following portfolios are considered:

1. BESS + onshore wind + solar PV (utility-scale and rooftop)
2. BESS + RICE + onshore wind + solar PV (utility-scale and rooftop)
3. BESS + CTs + onshore wind + solar PV (utility-scale and rooftop)
4. RICE or CTs + onshore wind + solar PV (utility-scale and rooftop)

The key considerations when developing these different portfolios are discussed as follows. Note that each of the above portfolios also assume the continued implementation and growth of the PEI DSM program.

6.1.1. Need for Additional Capacity

Additional capacity is needed on PEI. Due to the retirement of the Charlottetown oil-fired generators, Maritime Electric has had to increase the amount of capacity it purchases from the mainland to meet its regional obligations from 40% to over 60%. This leaves Maritime Electric and PEI vulnerable on a number of fronts.

First, it leaves Maritime Electric's customers more exposed to the economic repercussions of a likely capacity shortfall in the Maritimes region due to the retirement of coal throughout Canada by 2030 (as is discussed in further detail in Section 2.4.1). The retirement of coal will necessitate significant changes to the generation portfolios of PEI's immediate neighbours. For reference, coal generation makes up 41% of Nova Scotia's generation portfolio (1,234 MW) and 12% of New Brunswick's portfolio (467 MW). While

PEI's neighbours are planning on developing new capacity to replace their to be retired coal power plants, the level of investment and mobilization needed to replace all of the retired coal capacity is significant considering that the retirement deadline for the coal power plants is less than a decade away. As a result, some of this retired coal capacity will be met with market purchases or purchases from neighbours, as Nova Scotia Power is planning per discussion in their IRP; however, there currently is not enough transmission infrastructure in place for this increase in capacity demand to be met as cost effectively as possible. Separately, there is a forecasted increase in electrical demand in both the Maritimes region and in the northeastern United States over the next decade, which will further increase the capacity obligations of the regional utilities. All of this is likely to result in more competition and thus higher prices for regional capacity if the development of new generating resources and the implementation of regional energy efficiency programs cannot keep pace with demand growth. Any increase in capacity costs for Maritime Electric will be borne by Maritime Electric's customers.

In addition, the lack of capacity leaves Maritime Electric's customers vulnerable in the event of an electrical disconnection of PEI from the mainland. This situation has occurred a number of times in recent history (see Section 2.2.3). In the event that PEI is electrically disconnected from the mainland in the winter (the season where system electrical demand is highest), there is not enough on-island generation installed to meet system load (as is discussed in detail in Section 2.2). As a result, Maritime Electric will be forced to implement rolling blackouts. With additional on-island capacity, the rolling blackouts will either become unnecessary (if enough capacity is added to fully meet load) or the severity of the rolling blackouts will decrease. Given the potential repercussions of blackouts can be life threatening, it is critical Maritime Electric add on-island capacity. As discussed in Section 2.2.4, we estimate that a minimum of 85 MW of dispatchable capacity needs to be added to the system to be able to bring the ratio of total dispatchable capacity versus winter peak load back in line with historical levels. An additional 40 MW will likely be required when the existing Borden generating units have reached end of life and are retired. Without this level of additional capacity, it is highly likely that any future rolling blackouts that result from a disconnection of PEI from the mainland will be much more severe than those that have occurred in the past.

Of the remaining resources that have passed the secondary screening, only BESS, RICE, and CTs are effective sources of capacity. While wind and solar PV are excellent sources of energy, they are poor sources of capacity. From a cost perspective, both RICE and CT's cost less than a 4-hour BESS (4 hours is one of the most common BESS durations in the energy industry). An important additional consideration regarding BESS, is that it would not be as dependable for Maritime Electric as RICE or CTs would be during a disconnection from the mainland. The reason for this is because the level of support a BESS could provide during a disconnection is dependent on a number of external variables, such as the state of charge of the BESS when the disconnection occurs, wind generation during the disconnection, and the length of time before the connection to the mainland can be restored. At best, a BESS system could be very helpful for

Maritime Electric during a disconnection from the mainland; however, at worst (i.e., when the state of charge of the BESS was low when the disconnection occurred and the wind generators were in emergency shutdown), a BESS system would be ineffective at supporting the system.

6.1.2. Meeting Sustainability Targets

Maritime Electric needs to pursue more carbon free generation in order it to meet its sustainability target of reducing greenhouse gas emissions by 55% by 2030 (from 2019 levels). Of the remaining resources that have passed the secondary screening, onshore wind and solar PV (both utility-scale and rooftop) are carbon-free generation sources. Given PEI's excellent onshore wind resource and the relatively low cost to build onshore wind power plants, the continued development of onshore wind should be a main priority for Maritime Electric and PEI. While solar PV will not provide near the same amount of generation for Maritime Electric on a per dollar invested basis as onshore wind, solar PV does have some benefits that make it worth consideration. First, it provides generation diversity to Maritime Electric's portfolio. More specifically, wind and solar generation are not perfectly correlated; thus, the integration of solar PV will help to provide some balance to the island's hourly generation. Additionally, solar PV is relatively low-cost. As a result of these reasons, it is recommended that Maritime Electric and PEI pursue the development of some utility-scale solar PV projects and continue to encourage and support the development of rooftop solar PV on the island.

As discussed earlier (see Section 3.2.1), BESS will have a limited ability to help Maritime Electric meet its sustainability targets. In order for BESS to be able to help Maritime Electric meet its sustainability targets, it would have to be able to charge from a carbon-free resource during a time when that resource's generation could not be used on the island, and discharge that energy back into the system at a later time. At present, there are very rarely times when the generation produced from PEI's carbon-free resources (e.g., the wind farms on PEI) cannot be used immediately to serve load. As more wind generation is installed on PEI, there will be more frequent instances where high amounts of hourly wind generation will result in an oversupply of electricity – a future BESS project could shift this excess electricity to other times. However, the forecasted frequency at which additional wind generation will cause an oversupply of electricity in the future is likely not going to be high enough to fully justify the cost to install a new BESS project.

6.2. PORTFOLIOS CONSIDERED

6.2.1. Portfolio A: BESS + Onshore Wind + Solar PV

The combination of BESS, onshore wind, and solar PV would provide Maritime Electric with carbon-free generation to help meet both its energy obligations and sustainability targets, along with storage to meet its regional capacity obligations. The wind and solar PV would reduce the amount of energy needed to be purchased from NBEM. In addition, the combination of this additional energy from the wind and solar PV projects, combined with the capacity from the BESS, will help to provide a buffer against regional market price volatility in energy and capacity.

A BESS project could offer some additional advantages for Maritime Electric in addition to providing capacity to meet regional obligations. For example, a BESS project could allow Maritime Electric to pursue an energy arbitrage strategy if it wished to participate in an energy marketplace. Additionally, a BESS project could provide various ancillary services and system electrical support for Maritime Electric. While a single BESS project is unlikely to be able to provide all of the different possible functions simultaneously, it can be used for multiple functions. To better assess and quantify the potential benefits a BESS might be able to provide, an approach Maritime Electric could pursue is working with the PEI government to develop a demonstration 4-hour BESS project. As a demonstration project, Maritime Electric and PEI would be better able to assess which functions/use cases future BESS projects might be utilized for to maximize the benefit for PEI and Maritime Electric's customers.

Portfolio A does run into a few challenges when considering an electrical disconnection of PEI from the mainland. Because of their intermittency, onshore wind and solar PV energy are both unreliable resources during a disconnection. If either the onshore wind, solar PV, or both are not operating, no electricity is being generated. While the BESS can support the system, the amount of support it can provide is difficult to forecast since it depends on its state of charge, generation from the wind/solar PV, and the length of the disconnection. If the BESS was unable to provide much support to the system, Maritime Electric would be completely reliant on the few existing dispatchable generators it has on the island (which is the position Maritime Electric is currently in today), which are not sufficient to allow Maritime Electric to avoid severe rolling blackouts.

The following tables provide the forecasted capacity, energy, and emissions sources for this portfolio. Note that the new BESS project marginally increases the amount of wind energy Maritime Electric can utilize to serve load because BESS can capture a portion of the wind generation that would otherwise have to be sold back to the mainland during periods where there is excess total generation beyond load. In addition, while it is difficult to forecast exactly how much a new BESS project would be able to reduce the need for the on-island diesel generators, it is assumed that the BESS reduces on-island diesel generator dispatch by 50%.

Note that the tables assume a 50 MW, 4-hour duration BESS is added to the system, not 85 MW of additional capacity (see Section 2.2.4 for the basis of the 85 MW recommendation). The reason for this is because the 85 MW capacity recommendation is for fully dispatchable capacity that would specifically be able to help Maritime Electric better manage a situation where PEI is electrically disconnected from the mainland. As discussed, a new BESS project might not be dispatchable during a disconnection from the mainland. As such, the capacity of a new BESS project is not considered to be able to fully satisfy the dispatchability requirements associated with the 85 MW capacity recommendation in Section 2.2.4. Instead, this portfolio considers a 50 MW BESS project to minimize portfolio costs.

Table 6-1 — Estimated Portfolio A Capacity Sources

Portfolio A	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Capacity Obligation (MW):										
MECL Peak Load (Net of DSM)	284	289	293	299	305	311	317	323	329	335
Less Interruptible Load	14	14	14	14	14	14	14	14	14	14
Plus 15 % Planning Reserve	41	41	42	43	44	45	45	46	47	48
Total MECL Capacity Obligation (MW)	**311**	**316**	**321**	**328**	**335**	**342**	**348**	**355**	**362**	**369**
A) MECL Capacity Resources (MW):										
Borden Generating Station (CTs)	40	40	40	40	40	40	40	0	0	0
Charlottetown CT3	49	49	49	49	49	49	49	49	49	49
Point Lepreau Nuclear	29	29	29	29	29	29	29	29	29	29
Short Term Capacity Purchases (NBEM)	172	174	129	132	139	146	153	200	207	214
New BESS	0	0	50	50	50	50	50	50	50	50
Subtotal (MW)	*290*	*292*	*297*	*300*	*307*	*314*	*321*	*328*	*335*	*342*
B) Wind Power (MW):										
MECL Purchasd Nameplate Capacity	92	122	122	162	162	162	162	162	162	162
ELCC as % of Purchased	23%	20%	20%	17%	17%	17%	17%	17%	17%	17%
ELCC (MW)	*21*	*24*	*24*	*28*	*28*	*28*	*28*	*28*	*28*	*28*
C) Solar PV Power (MW):										
Rooftop Solar	15	15	15	15	15	15	15	15	15	15
Utility Scale	0	0	20	30	40	50	60	60	60	60
ELCC as % of Purchased	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
ELCC (MW)	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Total MECL Capacity (A+B+C) (MW)	**311**	**316**	**321**	**328**	**335**	**342**	**348**	**355**	**362**	**369**

Table 6-2 — Estimated Portfolio A Energy Sources

Portfolio A	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Energy Obligation (GWh)	**1,495**	**1,517**	**1,538**	**1,561**	**1,588**	**1,615**	**1,642**	**1,668**	**1,694**	**1,722**
MECL Energy Supply (GWh):										
Borden Generating Station (CTs)	1.1	1.1	0.6	0.6	0.6	0.6	0.6	0	0	0
Charlottetown CT3	1.4	1.4	0.7	0.7	0.7	0.7	0.7	1.3	1.3	1.3
Point Lepreau Nuclear	210	210	210	210	210	210	210	210	210	210
Energy Purchases (NBEM)	968	879	863	712	721	731	740	766	793	820
New BESS	0	0	0	0	0	0	0	0	0	0
Wind Power	295	406	408	566	566	566	566	566	566	566
Rooftop Solar PV	20	20	20	20	20	20	20	20	20	20
Utility Scale Solar PV	0	0	35	52	70	87	105	105	105	105
Total Energy (GWh)	**1,495**	**1,517**	**1,538**	**1,561**	**1,588**	**1,615**	**1,642**	**1,668**	**1,694**	**1,722**

Table 6-3 — Estimated Portfolio A Emissions Sources

Portfolio A	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Emissions (kilo-Tonnes CO_2e)										
Borden Generating Station (CTs)	1.2	1.2	0.6	0.6	0.6	0.6	0.6	0	0	0
Charlottetown CT3	1.4	1.4	0.7	0.7	0.7	0.7	0.7	1.3	1.3	1.3
Point Lepreau Nuclear	0	0	0	0	0	0	0	0	0	0
Energy Purchases (NBEM)	273	248	244	201	204	206	209	216	224	231
New BESS	0	0	0	0	0	0	0	0	0	0
Wind Power	0	0	0	0	0	0	0	0	0	0
Rooftop Solar PV	0	0	0	0	0	0	0	0	0	0
Utility Scale Solar PV	0	0	0	0	0	0	0	0	0	0
Total Emissions (kilo-Tonnes CO_2e)	**276**	**251**	**245**	**202**	**205**	**208**	**210**	**218**	**225**	**233**

Notes

1) Carbon emissions rates related to purchases from NBEM are based on 2019, 2020, and 2021 data compiled by Maritime Electric and contained in the 2022 Maritime Electric Sustainability Report (https://www.maritimeelectric.com/Media/1959/2022-sustainability-report_final_interactive-pdf_july-28-2022.pdf). Note the NBEM emissions rate (on a tonnes CO_2e per GWh basis) used to calculate carbon emissions is kept consistent for all the years shown in the table above; however, this rate is expected to fall with time as mainland utilities pursue various decarbonization strategies.

6.2.2. Portfolio B: BESS + RICE + Onshore Wind + Solar PV

A combination of onshore wind, solar PV, BESS and RICE would provide Maritime Electric with much of the same benefits as the previous portfolio, but with a much better ability to navigate an electrical disconnection from the mainland. The onshore wind and solar PV are both carbon-free sources of electricity that would help Maritime Electric both meet its sustainability targets and purchase less energy from NBEM. Both the BESS and RICE would also help Maritime Electric meet their capacity obligations.

The addition of the RICE does add a carbon emission consideration into the portfolio since a RICE power plant generates carbon emissions when it burns fuel. Because a RICE power plant would primarily serve as a backup generator and rarely operate, carbon emissions generated by the RICE power plant will be small and have little impact on Maritime Electric's ability to meet sustainability targets, but it could create a stranded asset problem for Maritime Electric if the government of Canada begins enforcing stricter rules on allowable fuels for power generation. One distinct advantage of a RICE power plant is that it can operate on fuels the government of Canada considers to be renewable, such as biodiesel[27]. The fact that RICE can operate on renewable fuels helps Maritime Electric avoid the risk that a new RICE power plant would become a stranded asset in the future if fuel regulations change.

A RICE power plant would also significantly help Maritime Electric during a disconnection from the mainland. The addition of a RICE power plant to PEI would provide Maritime Electric more dependable dispatchable capacity to both serve load and also to balance the wind generation intermittency during a

[27] RICE power plants are also likely to be able to operate on hydrogen in the coming years, but hydrogen operation would require a significant capital investment for the hydrogen infrastructure. Given a new RICE power plant would primarily be used as a backup generator, the investment in hydrogen infrastructure is likely not worth the investment for Maritime Electric.

disconnection, which would in turn allow Maritime Electric to utilize more of PEI's wind capacity without risking an imbalance of generation and load. While the BESS project could help support the system during a disconnection from the mainland in many of the same ways, the level of support it can provide depends on the BESS' state of charge, generation from the wind/solar PV, and the length of the disconnection, which are all difficult to forecast.

Similar to Portfolio A, a BESS project could offer some additional advantages for Maritime Electric in addition to providing capacity to meet regional obligations, such as allowing Maritime Electric to pursue an energy arbitrage strategy (if it wished to participate in an energy marketplace), providing various ancillary services and system electrical support to the system, among other items. As a demonstration project, Maritime Electric and PEI would be better able to assess which functions/use cases future BESS projects might be utilized for to maximize the benefit for PEI and Maritime Electric's customers.

The following tables provide the forecasted capacity, energy, and emissions sources for this portfolio. The new BESS project marginally increases the amount of wind energy Maritime Electric can utilize to serve load because BESS can capture a portion of the wind generation that would otherwise have to be sold back to the mainland during periods where there is excess generation beyond load. In addition, it is assumed that the new BESS allows Maritime Electric to be able to reduce on-island diesel generator dispatch by 50%.

Similar to Portfolio A, a 50 MW, 4-hour duration BESS is added to the system. In addition, a total of 85 MW of new RICE is added to this portfolio to be consistent with the recommendation in Section 2.2.4. Due to BESS' inability to be fully dispatchable during a disconnection from the mainland, the capacity of a new BESS project is not considered to be able to fully satisfy the dispatchability requirements associated with the 85 MW capacity recommendation in Section 2.2.4.

Table 6-4 — Estimated Portfolio B Capacity Sources

Portfolio B	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Capacity Obligation (MW):										
MECL Peak Load (Net of DSM)	284	289	293	299	305	311	317	323	329	335
Less Interruptible Load	14	14	14	14	14	14	14	14	14	14
Plus 15 % Planning Reserve	41	41	42	43	44	45	45	46	47	48
Total MECL Capacity Obligation (MW)	**311**	**316**	**321**	**328**	**335**	**342**	**348**	**355**	**362**	**369**
A) MECL Capacity Resources (MW):										
Borden Generating Station (CTs)	40	40	40	40	40	40	40	0	0	0
Charlottetown CT3	49	49	49	49	49	49	49	49	49	49
Point Lepreau Nuclear	29	29	29	29	29	29	29	29	29	29
Short Term Capacity Purchases (NBEM)	172	174	44	47	54	61	68	75	82	89
New BESS	0	0	50	50	50	50	50	50	50	50
New Reciprocating Engines (Biodiesel)	0	0	85	85	85	85	85	125	125	125
Subtotal (MW)	*290*	*292*	*297*	*300*	*307*	*314*	*321*	*328*	*335*	*342*
B) Wind Power (MW):										
MECL Purchasd Nameplate Capacity	92	122	122	162	162	162	162	162	162	162
ELCC as % of Purchased	23%	20%	20%	17%	17%	17%	17%	17%	17%	17%
ELCC (MW)	*21*	*24*	*24*	*28*	*28*	*28*	*28*	*28*	*28*	*28*
C) Solar PV Power (MW):										
Rooftop Solar	15	15	15	15	15	15	15	15	15	15
Utility Scale	0	0	20	30	40	50	60	60	60	60
ELCC as % of Purchased	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
ELCC (MW)	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Total MECL Capacity (A+B+C) (MW)	**311**	**316**	**321**	**328**	**335**	**342**	**348**	**355**	**362**	**369**

Table 6-5 — Estimated Portfolio B Energy Sources

Portfolio B	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Energy Obligation (GWh)	**1,495**	**1,517**	**1,538**	**1,561**	**1,588**	**1,615**	**1,642**	**1,668**	**1,694**	**1,722**
MECL Energy Supply (GWh):										
Borden Generating Station (CTs)	1.1	1.1	0.3	0.3	0.3	0.3	0.3	0	0	0
Charlottetown CT3	1.4	1.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Point Lepreau Nuclear	210	210	210	210	210	210	210	210	210	210
Energy Purchases (NBEM)	968	879	863	712	721	731	740	766	793	820
New BESS	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines (Biodiesel)	0	0	0.6	0.6	0.6	0.6	0.6	0.9	0.9	0.9
Wind Power	295	406	408	566	566	566	566	566	566	566
Rooftop Solar PV	20	20	20	20	20	20	20	20	20	20
Utility Scale Solar PV	0	0	35	52	70	87	105	105	105	105
Total Energy (GWh)	**1,495**	**1,517**	**1,538**	**1,561**	**1,588**	**1,615**	**1,642**	**1,668**	**1,694**	**1,722**

Table 6-6 — Estimated Portfolio B Emissions Sources

Portfolio B	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Emissions (kilo-Tonnes CO_2e)										
Borden Generating Station (CTs)	1.2	1.2	0.3	0.3	0.3	0.3	0.3	0	0	0
Charlottetown CT3	1.4	1.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Point Lepreau Nuclear	0	0	0	0	0	0	0	0	0	0
Energy Purchases (NBEM)	273	248	244	201	204	206	209	216	224	231
New BESS	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines (Biodiesel)	0	0	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Wind Power	0	0	0	0	0	0	0	0	0	0
Rooftop Solar PV	0	0	0	0	0	0	0	0	0	0
Utility Scale Solar PV	0	0	0	0	0	0	0	0	0	0
Total Emissions (kilo-Tonnes CO_2e)	**276**	**251**	**244**	**202**	**204**	**207**	**210**	**217**	**224**	**232**

Notes

1) Carbon emissions rates related to purchases from NBEM are based on 2019, 2020, and 2021 data compiled by Maritime Electric and contained in the 2022 Maritime Electric Sustainability Report (https://www.maritimeelectric.com/Media/1959/2022-sustainability-report_final_interactive-pdf_july-28-2022.pdf). Note the NBEM emissions rate (on a tonnes CO_2e per GWh basis) used to calculate carbon emissions is kept consistent for all the years shown in the table above; however, this rate is expected to fall with time as mainland utilities pursue various decarbonization strategies.
2) Biodiesel emissions assume B100 fuel is used and are calculated assuming the lifecycle emissions (from the production of the B100 fuel through combustion) are 70% less than traditional diesel fuel. The actual lifecycle emissions may vary based on a number of factors, including fuel composition, production method, etc. Note that the Canadian government considers biodiesel as a renewable fuel.

6.2.3. Portfolio C: BESS + Combustion Turbines + Onshore Wind + Solar PV

This portfolio is very similar to the previous portfolio in that it contains both renewable and dispatchable generation. While the technologies are different, RICE and CTs are very similar in how they would be utilized by Maritime Electric, the type of support they can provide to an electrical system, and the types of fuel they can operate on. As a result, all of the information discussed for the previous portfolio (BESS + RICE + onshore wind + solar PV) is consistent for this portfolio.

There are some small differences between RICE and CTs that are worth mentioning. The first difference is cost. We estimate a slight cost premium to pursue CTs instead of RICE, estimated at between 5% and 10% depending on the fuel type considered (biodiesel versus diesel). Included in this price premium are some equipment modifications that would be required to convert a CT to be able to burn biodiesel. A RICE would not require modification to burn either fuel. Both RICE and CTs would require minor modifications to balance of plant/fuel storage. Finally, CTs burn between 10% and 20% more fuel on a per output basis than RICE (i.e., they are less fuel efficient), depending on the type of fuel. Given the slight cost premium and lower fuel efficiency of CTs versus RICE, we consider a portfolio with RICE to be a better option for Maritime Electric; however, the two technologies have so many similarities that either would be a sound choice.

The following tables provide the forecasted capacity, energy, and emissions sources for this portfolio. The new BESS project marginally increases the amount of wind energy Maritime Electric can utilize to serve load because BESS can capture a portion of the wind generation that would otherwise have to be sold back to the mainland during periods where there is excess generation beyond load. In addition, it is assumed that the new BESS allows Maritime Electric to be able to reduce on-island diesel generator dispatch by 50%.

Similar to Portfolios A and B, a 50 MW, 4-hour duration BESS is added to the system. In addition, a total of 85 MW of new CTs are added to this portfolio to be consistent with the recommendation in Section 2.2.4. Due to BESS' inability to be fully dispatchable during a disconnection from the mainland, the capacity of a new BESS project is not considered to be able to fully satisfy the dispatchability requirements associated with the 85 MW capacity recommendation in Section 2.2.4.

Table 6-7 — Estimated Portfolio C Capacity Sources

Portfolio C	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Capacity Obligation (MW):										
MECL Peak Load (Net of DSM)	284	289	293	299	305	311	317	323	329	335
Less Interruptible Load	14	14	14	14	14	14	14	14	14	14
Plus 15 % Planning Reserve	41	41	42	43	44	45	45	46	47	48
Total MECL Capacity Obligation (MW)	**311**	**316**	**321**	**328**	**335**	**342**	**348**	**355**	**362**	**369**
A) MECL Capacity Resources (MW):										
Borden Generating Station (CTs)	40	40	40	40	40	40	40	0	0	0
Charlottetown CT3	49	49	49	49	49	49	49	49	49	49
Point Lepreau Nuclear	29	29	29	29	29	29	29	29	29	29
Short Term Capacity Purchases (NBEM)	172	174	44	47	54	61	68	75	82	89
New BESS	0	0	50	50	50	50	50	50	50	50
New CTs (Biodiesel)	0	0	85	85	85	85	85	125	125	125
Subtotal (MW)	*290*	*292*	*297*	*300*	*307*	*314*	*321*	*328*	*335*	*342*
B) Wind Power (MW):										
MECL Purchasd Nameplate Capacity	92	122	122	162	162	162	162	162	162	162
ELCC as % of Purchased	23%	20%	20%	17%	17%	17%	17%	17%	17%	17%
ELCC (MW)	*21*	*24*	*24*	*28*	*28*	*28*	*28*	*28*	*28*	*28*
C) Solar PV Power (MW):										
Rooftop Solar	15	15	15	15	15	15	15	15	15	15
Utility Scale	0	0	20	30	40	50	60	60	60	60
ELCC as % of Purchased	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
ELCC (MW)	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Total MECL Capacity (A+B+C) (MW)	**311**	**316**	**321**	**328**	**335**	**342**	**348**	**355**	**362**	**369**

Table 6-8 — Estimated Portfolio C Energy Sources

Portfolio C	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Energy Obligation (GWh)	**1,495**	**1,517**	**1,538**	**1,561**	**1,588**	**1,615**	**1,642**	**1,668**	**1,694**	**1,722**
MECL Energy Supply (GWh):										
Borden Generating Station (CTs)	1.1	1.1	0.3	0.3	0.3	0.3	0.3	0	0	0
Charlottetown CT3	1.4	1.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Point Lepreau Nuclear	210	210	210	210	210	210	210	210	210	210
Energy Purchases (NBEM)	968	879	863	712	721	731	740	766	793	820
New BESS	0	0	0	0	0	0	0	0	0	0
New CTs (Biodiesel)	0	0	0.6	0.6	0.6	0.6	0.6	0.9	0.9	0.9
Wind Power	295	406	408	566	566	566	566	566	566	566
Rooftop Solar PV	20	20	20	20	20	20	20	20	20	20
Utility Scale Solar PV	0	0	35	52	70	87	105	105	105	105
Total Energy (GWh)	**1,495**	**1,517**	**1,538**	**1,561**	**1,588**	**1,615**	**1,642**	**1,668**	**1,694**	**1,722**

Table 6-9 — Estimated Portfolio C Emissions Sources

Portfolio C	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Emissions (kilo-Tonnes CO_2e)										
Borden Generating Station (CTs)	1.2	1.2	0.3	0.3	0.3	0.3	0.3	0	0	0
Charlottetown CT3	1.4	1.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Point Lepreau Nuclear	0	0	0	0	0	0	0	0	0	0
Energy Purchases (NBEM)	273	248	244	201	204	206	209	216	224	231
New BESS	0	0	0	0	0	0	0	0	0	0
New CTs (Biodiesel)	0	0	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Wind Power	0	0	0	0	0	0	0	0	0	0
Rooftop Solar PV	0	0	0	0	0	0	0	0	0	0
Utility Scale Solar PV	0	0	0	0	0	0	0	0	0	0
Total Emissions (kilo-Tonnes CO_2e)	**276**	**251**	**244**	**202**	**204**	**207**	**210**	**217**	**224**	**232**

Notes

1) Carbon emissions rates related to purchases from NBEM are based on 2019, 2020, and 2021 data compiled by Maritime Electric and contained in the 2022 Maritime Electric Sustainability Report (https://www.maritimeelectric.com/Media/1959/2022-sustainability-report_final_interactive-pdf_july-28-2022.pdf). Note the NBEM emissions rate (on a tonnes CO_2e per GWh basis) used to calculate carbon emissions is kept consistent for all the years shown in the table above; however, this rate is expected to fall with time as mainland utilities pursue various decarbonization strategies.
2) Biodiesel emissions assume B100 fuel is used and are calculated assuming the lifecycle emissions (from the production of the B100 fuel through combustion) are 70% less than traditional diesel fuel. The actual lifecycle emissions may vary based on a number of factors, including fuel composition, production method, etc. Note that the Canadian government considers biodiesel as a renewable fuel.

6.2.4. Portfolio D: RICE or Combustion Turbines + Onshore Wind + Solar PV

This portfolio is similar to the previous portfolios but forgoes the inclusion of a battery. Given the similarities between RICE and CTs, this portfolio considers that either technology is pursued, albeit with a cost premium if CTs are pursued since they are slightly more expensive than RICE. The combination of RICE or CTs, onshore wind, and solar PV would provide Maritime Electric with carbon-free generation to help meet both its energy obligations and sustainability targets, along with capacity to meet its regional obligations. The wind and solar PV would reduce the amount of energy needed to be purchased from NBEM. In addition, the combination of this additional energy from the wind and solar PV projects, combined with the capacity from the RICE or CTs, will help to provide a buffer against regional market price volatility in energy and capacity.

The fact that both RICE and CTs can operate on fuels that are considered to be renewable (i.e., biodiesel) also helps Maritime Electric to avoid investing in an asset that might become stranded in the event that the government of Canada changes regulations on allowable fuels for power generation.

Also, as previously discussed, RICE and CT power plants would significantly help Maritime Electric during a disconnection of PEI from the mainland. These generators would provide Maritime Electric more dependable dispatchable capacity to both serve load and also to balance the wind generation intermittency during a disconnection, which would in turn allow Maritime Electric to utilize more of PEI's wind capacity without risking an imbalance of generation and load. This will either help to eliminate or reduce the severity of rolling blackouts if PEI becomes disconnected from the mainland.

The following tables provide the forecasted capacity, energy, and emissions sources for this portfolio. A total of 85 MW of new CTs are added to this portfolio to be consistent with the recommendation in Section 2.2.4.

Table 6-10 — Estimated Portfolio D Capacity Sources

Portfolio D	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Capacity Obligation (MW):										
MECL Peak Load (Net of DSM)	284	289	293	299	305	311	317	323	329	335
Less Interruptible Load	14	14	14	14	14	14	14	14	14	14
Plus 15 % Planning Reserve	41	41	42	43	44	45	45	46	47	48
Total MECL Capacity Obligation (MW)	**311**	**316**	**321**	**328**	**335**	**342**	**348**	**355**	**362**	**369**
A) MECL Capacity Resources (MW):										
Borden Generating Station (CTs)	40	40	40	40	40	40	40	0	0	0
Charlottetown CT3	49	49	49	49	49	49	49	49	49	49
Point Lepreau Nuclear	29	29	29	29	29	29	29	29	29	29
Short Term Capacity Purchases (NBEM)	172	174	94	97	104	111	118	125	132	139
New Reciprocating Engines (Biodiesel)	0	0	85	85	85	85	85	125	125	125
Subtotal (MW)	*290*	*292*	*297*	*300*	*307*	*314*	*321*	*328*	*335*	*342*
B) Wind Power (MW):										
MECL Purchasd Nameplate Capacity	92	122	122	162	162	162	162	162	162	162
ELCC as % of Purchased	23%	20%	20%	17%	17%	17%	17%	17%	17%	17%
ELCC (MW)	*21*	*24*	*24*	*28*	*28*	*28*	*28*	*28*	*28*	*28*
C) Solar PV Power (MW):										
Rooftop Solar	15	15	15	15	15	15	15	15	15	15
Utility Scale	0	0	20	30	40	50	60	60	60	60
ELCC as % of Purchased	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
ELCC (MW)	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Total MECL Capacity (A+B+C) (MW)	**311**	**316**	**321**	**328**	**335**	**342**	**348**	**355**	**362**	**369**

Table 6-11 — Estimated Portfolio D Energy Sources

Portfolio D	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Energy Obligation (GWh)	**1,495**	**1,517**	**1,538**	**1,561**	**1,588**	**1,615**	**1,642**	**1,668**	**1,694**	**1,722**
MECL Energy Supply (GWh):										
Borden Generating Station (CTs)	1.1	1.1	0.6	0.6	0.6	0.6	0.6	0	0	0
Charlottetown CT3	1.4	1.4	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Point Lepreau Nuclear	210	210	210	210	210	210	210	210	210	210
Energy Purchases (NBEM)	968	879	865	719	729	738	747	774	800	827
New Reciprocating Engines (Biodiesel)	0	0	1.2	1.2	1.2	1.2	1.2	1.8	1.8	1.8
Wind Power	295	406	406	557	557	557	557	557	557	557
Rooftop Solar PV	20	20	20	20	20	20	20	20	20	20
Utility Scale Solar PV	0	0	35	52	70	87	105	105	105	105
Total Energy (GWh)	**1,495**	**1,517**	**1,538**	**1,561**	**1,588**	**1,615**	**1,642**	**1,668**	**1,694**	**1,722**

Table 6-12 — Estimated Portfolio D Emissions Sources

Portfolio D	Year									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MECL Emissions (kilo-Tonnes CO_2e)										
Borden Generating Station (CTs)	1.2	1.2	0.6	0.6	0.6	0.6	0.6	0	0	0
Charlottetown CT3	1.4	1.4	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Point Lepreau Nuclear	0	0	0	0	0	0	0	0	0	0
Energy Purchases (NBEM)	273	248	244	203	206	208	211	218	226	233
New Reciprocating Engines (Biodiesel)	0	0	0.4	0.4	0.4	0.4	0.4	0.6	0.6	0.6
Wind Power	0	0	0	0	0	0	0	0	0	0
Rooftop Solar PV	0	0	0	0	0	0	0	0	0	0
Utility Scale Solar PV	0	0	0	0	0	0	0	0	0	0
Total Emissions (kilo-Tonnes CO_2e)	**276**	**251**	**246**	**205**	**207**	**210**	**213**	**220**	**227**	**235**

Notes

1) Carbon emissions rates related to purchases from NBEM are based on 2019, 2020, and 2021 data compiled by Maritime Electric and contained in the 2022 Maritime Electric Sustainability Report (https://www.maritimeelectric.com/Media/1959/2022-sustainability-report_final_interactive-pdf_july-28-2022.pdf). Note the NBEM emissions rate (on a tonnes CO_2e per GWh basis) used to calculate carbon emissions is kept consistent for all the years shown in the table above; however, this rate is expected to fall with time as mainland utilities pursue various decarbonization strategies.
2) Biodiesel emissions assume B100 fuel is used and are calculated assuming the lifecycle emissions (from the production of the B100 fuel through combustion) are 70% less than traditional diesel fuel. The actual lifecycle emissions may vary based on a number of factors, including fuel composition, production method, etc. Note that the Canadian government considers biodiesel as a renewable fuel.

6.3. FINAL RECOMMENDATION

Based on the above discussions, the following portfolio is recommended for Maritime Electric:

- **Portfolio D**: RICE + Onshore Wind + Solar PV

This portfolio was selected due to its ability to most cost-effectively meet the three most critical needs of Maritime Electric: 1) meeting energy and regional capacity obligations, 2) supporting the system if PEI is disconnected from the mainland, and 3) supporting sustainability targets. For this portfolio, RICE was selected over CTs due to its lower cost and better fuel efficiency.

As discussed in Section 2.2.4, we estimate that a minimum of 85 MW of dispatchable capacity needs to be added to the system to be able to bring the ratio of total dispatchable capacity versus winter peak load back in line with historical levels. Without this level of additional capacity, it is highly likely that future rolling blackouts (that occur as a result of a disconnection of PEI from the mainland) will be much more severe than those that have occurred in the past. The additional capacity should be added to the system as soon as possible.

The reason BESS was not included in the recommended portfolio was primarily because of two reasons. First, a BESS solution is not as effective as the other shortlisted technologies at helping Maritime Electric meet its three most critical needs. Secondly, a BESS solution is a higher cost option than the other shortlisted technologies.

It is important to note that a BESS solution could offer some additional advantages for Maritime Electric beyond its three most critical needs, such as allowing Maritime Electric to pursue an energy arbitrage strategy (if they wished to participate in an energy marketplace in the future), providing various ancillary services and other system electrical support, and helping to manage times when there is excess wind generation (which will occur more frequently as more onshore wind is integrated onto PEI). If it were determined that a BESS solution should be pursued, we recommend Maritime Electric pursue working with the PEI government to develop a demonstration 4-hour BESS project. As a demonstration project, Maritime Electric and PEI would be better able to assess which functions/use cases future BESS projects might be utilized for to maximize the benefit for PEI and Maritime Electric’s customers.

APPENDIX A. CAPITAL COST ESTIMATES

This appendix contains generation/storage resource capital cost estimates. All values in Canadian dollars.

Thermal Units – Reciprocating Engines

Technology	**Reciprocating Internal Combustion Engine**	**Reciprocating Internal Combustion Engine**
Unit Type (Representative Manufacturer)	Wartsila 20V32 (5x)	Wartsila 20V32 (5x)
Cycle Type	Simple Cycle	Simple Cycle
Fuel Type	Diesel Fuel	Biodiesel Fuel
Net Plant Output (MW) - Summer (27˚C, 47% RH, 0 m)	53.0	46.9
Net Plant Output (MW) - Winter (-26˚C, 60% RH, 0 m)	53.0	46.9
Net Heat Rate (Btu/kWh) (HHV) (ISO: 15˚C, 60% RH, 0 m)	8,400	8,400
Project Costs		
Owner Furnished Equipment		
Prime Mover	$ 36,148,000	$ 36,148,000
Emission Control (assumed to not be required based on low capacity factors, low sulphur fuels to be used)	$ -	$ -
Sales Tax	$ 5,422,000	$ 5,422,000
Total Owner Furnished Equipment	$ 41,569,000	$ 41,569,000
EPC Costs		
Other Equipment	$ 7,081,000	$ 7,081,000
Diesel/Biodiesel Infrastructure (Fuel Handling and Storage)	$ 2,438,000	$ 2,754,000
Materials	$ 11,830,000	$ 11,830,000
Construction Labour	$ 15,135,000	$ 15,135,000
Other Labour	$ 6,562,000	$ 6,562,000
Sales Tax	$ 2,837,000	$ 2,837,000
EPC Contractor Fee	$ 5,077,000	$ 5,077,000
EPC Contingency	$ 6,996,000	$ 6,996,000
Total EPC Costs	$ 57,955,000	$ 57,955,000
Total Project Costs	$ 99,524,000	$ 99,524,000
Non-EPC Costs		
Project Development	$ 2,897,000	$ 2,897,000
Mobilization and Start-Up	$ 579,000	$ 579,000
Non-Fuel Inventories	$ 290,000	$ 290,000
Owner's Contingency	$ 4,636,000	$ 4,636,000
Electrical Interconnection	$ 2,700,000	$ 2,700,000
Land	$ 2,700,000	$ 2,700,000
Fuel Inventories	$ 5,461,000	$ 5,532,000
Working Capital	$ 869,000	$ 869,000
Subtotal - Non-EPC Costs w/o Financing Fees	$ 20,133,000	$ 20,204,000
	$ -	$ -
Total Non-EPC Costs	$ 20,133,000	$ 20,204,000
Overnight Capital Costs ($)	$ 119,657,000	$ 119,729,000
Overnight Capital Costs ($/kW)	$ 2,257	$ 2,556

(1) Costs based on EPC contracting approach.
(2) Interconnection and land costs are assumed values
(3) Property taxes and insurance costs are not included in the above estimate.

Thermal Units – Combustion Turbines

Technology	Combustion Turbine - Aeroderivative	Combustion Turbine - Aeroderivative	Combustion Turbine - Aeroderivative	Combustion Turbine - Aeroderivative	Combustion Turbine - Aeroderivative
Unit Type (Representative Manufacturer)	GE LM2500+ Aero (1x)	GE LM2500+ Aero (1x)	GE LM2500+ Aero (2x)	GE LM2500+ Aero (2x)	GE LM2500+ Aero (3x)
Cycle Type	Simple Cycle	Simple Cycle	Simple Cycle	Simple Cycle	Simple Cycle
Fuel Type	Diesel Fuel	Biodiesel Fuel	Diesel Fuel	Biodiesel Fuel	Diesel Fuel
Net Plant Output (MW) - Summer (27˚C, 47% RH, 0 m)	29.1	29.1	58.1	58.1	87.2
Net Plant Output (MW) - Winter (-26˚C, 60% RH, 0 m)	36.3	36.3	72.7	72.7	109.0
Net Heat Rate (Btu/kWh) (HHV) (ISO: 15˚C, 60% RH, 0 m)	9,500	10,000	9,500	10,000	9,500
Project Costs					
Owner Furnished Equipment					
Prime Mover	$ 23,940,000	$ 26,640,000	$ 41,681,000	$ 47,081,000	$ 57,652,000
Emission Control (assumed to not be required based on low capacity factors, low sulphur fuels to be used)	$ -	$ -	$ -	$ -	$ -
Sales Tax	$ 3,591,000	$ 3,996,000	$ 6,252,000	$ 7,062,000	$ 8,648,000
Total Owner Furnished Equipment	$ 27,531,000	$ 30,636,000	$ 47,933,000	$ 54,143,000	$ 66,300,000
EPC Costs					
Other Equipment	$ 7,240,000	$ 7,240,000	$ 12,606,000	$ 12,606,000	$ 17,436,000
Diesel/Biodiesel Infrastructure (Fuel Handling and Storage)	$ 1,584,000	$ 1,787,000	$ 3,166,000	$ 3,576,000	$ 4,749,000
Materials	$ 3,365,000	$ 3,365,000	$ 5,859,000	$ 5,859,000	$ 8,105,000
Construction Labour	$ 15,011,000	$ 15,011,000	$ 26,135,000	$ 26,135,000	$ 36,149,000
Other Labour	$ 3,908,000	$ 3,908,000	$ 6,805,000	$ 6,805,000	$ 9,412,000
Sales Tax	$ 1,591,000	$ 1,591,000	$ 2,770,000	$ 2,770,000	$ 3,831,000
EPC Contractor Fee	$ 3,614,000	$ 3,812,000	$ 6,317,000	$ 6,714,000	$ 8,759,000
EPC Contingency	$ 4,818,000	$ 5,083,000	$ 8,421,000	$ 8,952,000	$ 11,679,000
Total EPC Costs	$ 41,131,000	$ 41,798,000	$ 72,079,000	$ 73,417,000	$ 100,120,000
Total Project Costs	$ 68,662,000	$ 72,434,000	$ 120,012,000	$ 127,560,000	$ 166,420,000
Non-EPC Costs					
Project Development	$ 2,056,000	$ 2,090,000	$ 3,605,000	$ 3,671,000	$ 5,006,000
Mobilization and Start-Up	$ 412,000	$ 419,000	$ 721,000	$ 734,000	$ 1,002,000
Non-Fuel Inventories	$ 205,000	$ 209,000	$ 360,000	$ 367,000	$ 501,000
Owner's Contingency	$ 3,290,000	$ 3,344,000	$ 5,766,000	$ 5,874,000	$ 8,010,000
Electrical Interconnection	$ 2,025,000	$ 2,025,000	$ 3,510,000	$ 3,510,000	$ 4,860,000
Land	$ 2,700,000	$ 2,700,000	$ 2,700,000	$ 2,700,000	$ 2,700,000
Fuel Inventories	$ 3,387,000	$ 4,086,000	$ 6,774,000	$ 8,174,000	$ 10,161,000
Working Capital	$ 617,000	$ 626,000	$ 1,081,000	$ 1,102,000	$ 1,501,000
Subtotal - Non-EPC Costs w/o Financing Fees	$ 14,692,000	$ 15,499,000	$ 24,517,000	$ 26,132,000	$ 33,741,000
	$ -	$ -	$ -	$ -	$ -
Total Non-EPC Costs	$ 14,692,000	$ 15,499,000	$ 24,517,000	$ 26,132,000	$ 33,741,000
Overnight Capital Costs ($)	$ 83,354,000	$ 87,933,000	$ 144,530,000	$ 153,692,000	$ 200,160,000
Overnight Capital Costs ($/kW)	$ 2,867	$ 3,025	$ 2,486	$ 2,643	$ 2,295

(1) Costs based on EPC contracting approach.
(2) Interconnection and land costs are assumed values
(3) Property taxes and insurance costs are not included in the above estimate.

Battery Energy Storage – Lithium Ion

Technology	Battery Energy Storage System - Li-Ion (50 MW / 50 MWh, 1 hours)	Battery Energy Storage System - Li-Ion (50 MW / 100 MWh, 2 hours)	Battery Energy Storage System - Li-Ion (50 MW / 200 MWh, 4 hours)	Battery Energy Storage System - Li-Ion (50 MW / 400 MWh, 8 hours)	Battery Energy Storage System - Li-Ion (50 MW / 1,200 MWh, 24 hours)
Plant Nameplate Power (MW)	50	50	50	50	50
Storage Duration	1	2	4	8	24
Project Costs					
EPC Costs					
Batteries and Enclosures	$ 18,581,000	$ 37,162,000	$ 74,323,000	$ 148,647,000	$ 445,941,000
PCS and BOP Equipment	$ 5,276,000	$ 6,892,000	$ 8,774,000	$ 12,453,000	$ 24,905,000
BESS Equipment Subtotal	$ 23,857,000	$ 44,054,000	$ 83,098,000	$ 161,100,000	$ 470,846,000
Project Management	$ 2,793,000	$ 3,649,000	$ 4,645,000	$ 6,593,000	$ 13,185,000
Construction & Materials	$ 9,310,000	$ 12,163,000	$ 15,484,000	$ 21,976,000	$ 43,950,000
Sales Tax	$ 3,579,000	$ 6,608,000	$ 12,465,000	$ 24,165,000	$ 70,627,000
EPC Contractor Fee	Included	Included	Included	Included	Included
EPC Contingency	Included	Included	Included	Included	Included
Total EPC Costs	$ 39,539,000	$ 66,474,000	$ 115,692,000	$ 213,834,000	$ 598,608,000
Non-EPC Costs					
Project Development	$ 1,977,000	$ 3,324,000	$ 5,785,000	$ 10,692,000	$ 29,930,000
Mobilization and Start-Up	$ 395,000	$ 665,000	$ 1,157,000	$ 2,138,000	$ 5,986,000
Spare Parts Inventories					
Electrical Interconnection	$ 2,700,000	$ 2,700,000	$ 2,700,000	$ 2,700,000	$ 2,700,000
Land	$ 675,000	$ 675,000	$ 675,000	$ 675,000	$ 675,000
Working Capital	$ 395,000	$ 665,000	$ 1,157,000	$ 2,138,000	$ 5,986,000
Project Contingency	$ 2,284,000	$ 3,725,000	$ 6,358,000	$ 11,609,000	$ 32,194,000
Subtotal - Non-EPC Costs w/o Financing Fees	$ 8,427,000	$ 11,753,000	$ 17,832,000	$ 29,952,000	$ 77,472,000
Total Non-EPC Costs	$ 8,427,000	$ 11,753,000	$ 17,832,000	$ 29,952,000	$ 77,472,000
Overnight Capital Costs ($)	$ 47,966,000	$ 78,228,000	$ 133,523,000	$ 243,786,000	$ 676,079,000
Battery Energy Capital Costs ($/kWh)	$ 959	$ 782	$ 668	$ 609	$ 563
Battery Power Capacity Costs ($/kW)	$ 959	$ 1,565	$ 2,670	$ 4,876	$ 13,522

(1) Costs based on EPC contracting approach.
(2) Interconnection and land costs are assumed values
(3) Property taxes and insurance costs are not

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Onshore Wind

Technology	**Wind, On Shore**
Net Plant Output (MW)	50
Estimated Capacity Factor	45%
Estimated MWh per Year	197,100

Project Costs		
Owner Furnished Equipment		
WTG Procurement and Supply	$	52,738,000
Sales Tax	$	7,911,000
Total Owner Furnished Equipment	$	60,649,000
EPC Costs		
Civil / Structural / Architectural Subtotal	$	11,079,000
Turbine Erection	$	4,101,000
Mechanical Subtotal	$	4,101,000
Substation Electrical Equipment	$	2,807,000
Pad Mount Transformers and Collection System	$	9,426,000
Electrical Subtotal	$	12,232,000
Project Indirects	$	945,000
Sales Tax	$	1,835,000
EPC Contractor Fee	$	1,644,000
Total EPC Costs	$	31,837,000
Total Project Costs	$	92,485,000
Non-EPC Costs		
Owners Cost	$	4,605,000
Interconnection	$	2,700,000
Project Contingency	$	6,489,000
Subtotal - Non-EPC Costs w/o Financing Fees	$	13,794,000
Total Non-EPC Costs	$	13,794,000
Overnight Capital Costs	$	106,280,000
Overnight Capital Costs ($/kW)	$	2,126

(1) Costs based on EPC contracting approach.
(2) Interconnection costs are assumed values, land lease costs included in O&M
(3) Property taxes and insurance costs are not included in the above estimate.

Utility Scale Solar PV

Bifacial, fixed-tilt configuration

Technology	Utility Scale PV, Fixed Tilt ($50\ MW_{AC}$)
Net Plant Output (MW)	50
Estimated Capacity Factor	19.9%
Estimated MWh per Year	87,200

Project Costs		
Owner Furnished Equipment		
Modules	$	42,242,000
Sales Tax	$	6,337,000
Total Owner Furnished Equipment	$	48,578,000
EPC Costs		
Civil / Structural / Architectural Subtotal	$	5,238,000
Racking and Module Installation	$	16,467,000
Mechanical Subtotal	$	21,705,000
Inverters	$	3,910,000
Inverter Installation	$	1,292,000
PV BOP	$	3,930,000
DC/MV Collection, Miscellaneous	$	8,505,000
Substation	$	6,350,000
Electrical Subtotal	$	23,987,000
Project Indirects	$	1,019,000
Sales Tax	$	3,687,000
EPC Contractor Fee	$	2,597,000
Total EPC Costs	$	58,234,000
Total Project Costs	$	106,812,000
Non-EPC Costs		
Owners's Services	$	4,273,000
Interconnection	$	2,700,000
Project Contingency	$	5,689,000
Subtotal - Non-EPC Costs w/o Financing Fees	$	12,662,000
Total Non-EPC Costs	$	12,662,000
Total Capital Costs	$	119,474,000
Total Capital Costs ($/kW)	$	2,389

(1) Costs based on EPC contracting approach.
(2) Interconnection costs are assumed values, land lease costs included in O&M
(3) Property taxes and insurance costs are not included in the above estimate.

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Rooftop Solar PV

Technology	**Rooftop Solar, 10 kW, Fixed Tilt**
Net Plant Output (kW)	10
Estimated Capacity Factor	15%
Estimated kWh per Year	13,140

Project Costs	
Modules	$ 7,600
Inverters and BOP	$ 11,140
Labor and Overhead	$ 6,250
Permitting	$ 2,870
Up-Front Marketing / Customer Acquisition	$ 6,420
Developer Profit	$ 4,220
Sales Tax	$ 2,810
Total Capital Costs (Pre-Incentives)	$ 41,310
Total Capital Costs ($/kW) (Pre-Incentives)	$ 4,130
Residential Solar Rebate	$ 10,000
	-
Total Capital Costs (After Incentives)	$ 31,310
Total Capital Costs ($/kW) (After Incentives)	$ 3,131

Biomass Power Plant

Technology	Biomass Plant (50 MW)
Net Plant Output	50
Heat Rate (Btu/kWh)	13,300

Project Costs		
Owner Equipment and EPC Costs		
Mechanical, Boiler Plant, Including SCR	$	93,686,000
Mechanical, Turbine Plant	$	12,239,000
Mechanical, BOP	$	33,232,000
Mechanical Subtotal	$	139,157,000
Electrical, Main and Aux Power Systems	$	5,855,000
Electrical, BOP and I&C	$	29,176,000
Electrical, Substation and Switchyard	$	8,936,000
Electrical Subtotal	$	43,967,000
Civil / Structural Total	$	34,340,000
Sales Tax	$	9,534,000
Various Project Indirects	$	7,711,000
EPC Contractor Fee	$	9,697,000
EPC Contingency	$	10,873,000
Total Owner Equipment, and EPC Costs	$	255,278,000

Non-EPC Costs		
Owner's Services	$	18,182,000
Interconnection	$	2,700,000
Land	$	2,700,000
Project Contingency	$	13,943,000
Subtotal - Non-EPC Costs w/o Financing Fees	$	37,525,000
Total Non-EPC Costs	$	37,525,000
Overnight Capital Costs ($)		292,803,000
Overnight Capital Costs ($/kW)	$	5,856

(1) Costs based on EPC contracting approach.
(2) Interconnection and land costs are assumed values
(3) Property taxes and insurance costs are not included in the above estimate.

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APPENDIX B. O&M COST ESTIMATES

This appendix contains generation/storage resource operations and maintenance cost estimates. All values in Canadian dollars.

Thermal Units – Reciprocating Engines

Technology	**Reciprocating Internal Combustion Engine**	**Reciprocating Internal Combustion Engine**
Unit Type (Representative Manufacturer)	Wartsila 20V32 (5x)	Wartsila 20V32 (5x)
Cycle Type	Simple Cycle	Simple Cycle
Fuel Type	Diesel Fuel	Biodiesel Fuel
Net Plant Output (MW) - Summer (27˚C, 47% RH, 0 m)	53.0	46.9
Net Plant Output (MW) - Winter (-26˚C, 60% RH, 0 m)	53.0	46.9
Net Heat Rate (Btu/kWh) (HHV) (ISO: 15˚C, 60% RH, 0 m)	8,400	8,400
Fixed O&M		
Labor - Routine O&M	$ 315,000	$ 315,000
Maintenance Materials and Services	$ 68,000	$ 68,000
G&A	$ 118,000	$ 118,000
Total Fixed O&M ($)	$ 501,000	$ 501,000
Total Fixed O&M ($/kW-year)	$ 9.45	$ 10.69
Variable O&M		
Annualized Equipment Maintenance	203,078	203,078
VOM (non-fuel)	98,097	98,097
Variable O&M - Hours Based ($/MWh)	$ 64.86	$ 73.38

(1) O&M expenses assume low utilization (1% capacity factor); thus predominately allocate O&M spend on a variable basis.
(2) Given the low utilization, RICE and CT O&M expenses are assumed to be similar.

Thermal Units – Combustion Turbines

Technology	**Combustion Turbine - Aeroderivative**	**Combustion Turbine - Aeroderivative**	**Combustion Turbine - Aeroderivative**	**Combustion Turbine - Aeroderivative**	**Combustion Turbine - Aeroderivative**
Unit Type (Representative Manufacturer)	GE LM2500+ Aero (1x)	GE LM2500+ Aero (1x)	GE LM2500+ Aero (2x)	GE LM2500+ Aero (2x)	GE LM2500+ Aero (3x)
Cycle Type	Simple Cycle	Simple Cycle	Simple Cycle	Simple Cycle	Simple Cycle
Fuel Type	Diesel Fuel	Biodiesel Fuel	Diesel Fuel	Biodiesel Fuel	Diesel Fuel
Net Plant Output (MW) - Summer (27˚C, 47% RH, 0 m)	29.1	29.1	58.1	58.1	87.2
Net Plant Output (MW) - Winter (-26˚C, 60% RH, 0 m)	36.3	36.3	72.7	72.7	109.0
Net Heat Rate (Btu/kWh) (HHV) (ISO: 15˚C, 60% RH, 0 m)	9,500	10,000	9,500	10,000	9,500
Fixed O&M					
Labor - Routine O&M	$ 210,000	$ 210,000	$ 315,000	$ 315,000	$ 419,000
Maintenance Materials and Services	$ 37,000	$ 37,000	$ 75,000	$ 75,000	$ 112,000
G&A	$ 65,000	$ 65,000	$ 130,000	$ 130,000	$ 195,000
Total Fixed O&M ($)	$ 275,000	$ 275,000	$ 444,000	$ 444,000	$ 614,000
Total Fixed O&M ($/kW-year)	$ 9.44	$ 9.44	$ 7.64	$ 7.64	$ 7.04
Variable O&M					
Annualized Equipment Maintenance	111,373	111,373	222,747	222,747	334,120
VOM (non-fuel)	53,799	53,799	107,597	107,597	161,396
Variable O&M - Hours Based ($/MWh)	$ 64.86	$ 64.86	$ 64.86	$ 64.86	$ 64.86

(1) O&M expenses assume low utilization (1% capacity factor); thus predominately allocate O&M spend on a variable basis.
(2) Given the low utilization, RICE and CT O&M expenses are assumed to be similar.

Battery Energy Storage – Lithium Ion

Technology	Battery Energy Storage System - Li-Ion (50 MW / 50 MWh, 1 hours)	Battery Energy Storage System - Li-Ion (50 MW / 100 MWh, 2 hours)	Battery Energy Storage System - Li-Ion (50 MW / 200 MWh, 4 hours)	Battery Energy Storage System - Li-Ion (50 MW / 400 MWh, 8 hours)	Battery Energy Storage System - Li-Ion (50 MW / 1,200 MWh, 24 hours)
Plant Nameplate Power (MW)	50	50	50	50	50
Storage Duration	1	2	4	8	24
Fixed O&M					
Augmentation Expense (Total Expense, Divided Out Per Year)	$ 346,000	$ 575,000	$ 992,000	$ 1,822,000	$ 5,073,000
O&M Labor	$ 60,000	$ 133,000	$ 322,000	$ 729,000	$ 2,355,000
O&M Production and Parts	$ 7,000	$ 15,000	$ 37,000	$ 83,000	$ 268,000
O&M Fee and G&A	$ 82,000	$ 183,000	$ 443,000	$ 1,002,000	$ 3,238,000
Station Load / Aux Load	$ 8,000	$ 18,000	$ 43,000	$ 97,000	$ 312,000
Miscellaneous Costs	$ 6,000	$ 13,000	$ 32,000	$ 72,000	$ 233,000
Fixed O&M ($/kWh-yr)	$ 3.12	$ 3.49	$ 4.39	$ 4.78	$ 5.14
Fixed O&M ($/kW-yr)	$ 3.12	$ 6.98	$ 17.54	$ 38.22	$ 123.47
Fixed O&M including Augmentation ($/kW-year)	$ 10.03	$ 18.49	$ 37.38	$ 74.66	$ 224.92
Variable O&M					

Included in FOM Above (Assumes 1 Cycle/Day)

(1) Calculations assume 3 augmentations over 20 years, spaced at 5 year intervals.

Onshore Wind

Technology	**Wind, On Shore**
Net Plant Output (MW)	50
Estimated Capacity Factor	45%
Estimated MWh per Year	197,100

Fixed O&M

WTG Scheduled Maintenance	$	625,000
WTG Unscheduled Maintenance	$	601,000
BOP Maintenance	$	120,000
Labor	$	421,000
Operations	$	234,000
Other (includes land lease)	$	925,000
Total Fixed O&M ($)	$	2,926,000
Total Fixed O&M ($/kW-year)	$	59

Variable O&M

Variable O&M ($/MWh)	$	-

(1) Assumes O&M is performed by an independent service provider
(2) All O&M costs are on a fixed-cost basis

Utility Scale Solar PV

Bifacial, fixed-tilt configuration

Technology	**Utility Scale PV, Fixed Tilt ($50\ MW_{AC}$)**
Net Plant Output (MW)	50
Estimated Capacity Factor	19.9%
Estimated MWh per Year	87,200
Fixed O&M	
Preventative Maintenance	$ 586,000
Module Cleaning	$ 326,000
Unscheduled Maintenance	$ 51,000
Inverter Maintenance Reserve	$ 182,000
Land Lease	$ 71,000
Total Fixed O&M ($)	$ 1,215,000
Total Fixed O&M ($/kW-year)	$ 24.30
Variable O&M	
Variable O&M ($/MWh)	$ -

**Note: If a 50 MW solar power plant is built as 5 different 10MW individual locations, it will likely utilize central inverters. By contrast, if a larger number of smaller MW locations are developed, it is more likely that string inverters will be utilized. Costs for string vs. central inverters vary slightly on a capital and O&M basis, but differences are unlikely to be significant enough to exclusively drive development decisions over other considerations.*

Biomass Power Plant

Technology	**Biomass Plant (50 MW)**
Net Plant Output	50
Heat Rate (Btu/kWh)	13,300
Fixed O&M	
Labor (Full Time Equivalents)	
Labor	$ 5,054,000
Materials and Contract Services	$ 2,025,000
Administrative and General	$ 2,430,000
Total Fixed O&M ($)	$ 9,509,000
Total Fixed O&M ($/kW-year)	$ 190
Variable O&M	
Variable O&M - Hours Based ($/MWh)	$ 7.45

The following table presents a 20-year comparison of operational costs for a 50 MW (4-hour duration) BESS to a similar sized RICE project. In order to maintain a consistent BESS performance level, the BESS project is assumed to be augmented every 5 years to counteract the impact of BESS degradation. A BESS project does not have to be augmented; however, a typical non-augmented project can be expected to degrade approximately 25% to 30% over a 20-year lifespan. All values in the table below are presented in 2022 Canadian Dollars.

		Yearly Costs, 2022 $'s																			
	20 Year Total (2022 $'s)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
50 MW / 200 MWh BESS (1 cycle/day)																					
Augmentation Expense (CAD '000)	19,836	0	0	0	0	7,023	0	0	0	0	6,595	0	0	0	0	6,218	0	0	0	0	0
Fixed O&M (CAD '000)																					
O&M Labor	6,448	293	296	299	302	305	308	311	314	317	320	323	327	330	333	336	340	343	346	350	353
O&M Production and Parts	734	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
O&M Fee and G&A	8,867	403	407	411	415	419	424	428	432	436	440	445	449	454	458	462	467	472	476	481	486
Station Load / Aux Load	855	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Miscellaneous Costs	638	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
Total Expenses (CAD '000)	**37,377**	*808*	*815*	*822*	*829*	*7,859*	*843*	*850*	*857*	*865*	*7,467*	*880*	*887*	*895*	*902*	*7,129*	*918*	*926*	*934*	*942*	*950*
Total Expenses (CAD/kW-year)	**37.4**	**16.2**	**16.3**	**16.4**	**16.6**	**157.2**	**16.9**	**17.0**	**17.1**	**17.3**	**149.3**	**17.6**	**17.7**	**17.9**	**18.0**	**142.6**	**18.4**	**18.5**	**18.7**	**18.8**	**19.0**
Total Expenses, O&M Only (CAD '000)	**17,541**	*808*	*815*	*822*	*829*	*836*	*843*	*850*	*857*	*865*	*872*	*880*	*887*	*895*	*902*	*910*	*918*	*926*	*934*	*942*	*950*
Total Expenses, O&M Only (CAD/kW-year)	**17.5**	**16.2**	**16.3**	**16.4**	**16.6**	**16.7**	**16.9**	**17.0**	**17.1**	**17.3**	**17.4**	**17.6**	**17.7**	**17.9**	**18.0**	**18.2**	**18.4**	**18.5**	**18.7**	**18.8**	**19.0**
53 MW RICE (App. 1% Capacity Factor)																					
Fixed O&M (CAD '000)																					
Labor - Routine O&M (1.5 FTE)	6,290	286	289	292	295	298	301	303	306	309	312	316	319	322	325	328	331	335	338	341	345
Maintenance Materials and Services	1,362	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
G&A	2,365	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118
Variable O&M (CAD '000)																					
Annualized Equipment Maintenance	4,062	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203
VOM (non-fuel)	1,962	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Total Expenses (CAD '000)	**16,042**	*774*	*777*	*779*	*782*	*785*	*788*	*791*	*794*	*797*	*800*	*803*	*806*	*809*	*812*	*816*	*819*	*822*	*825*	*829*	*832*
Fixed O&M (CAD/kW-year)	**9.5**	**14.6**	**14.7**	**14.7**	**14.8**	**14.8**	**14.9**	**14.9**	**15.0**	**15.0**	**15.1**	**15.2**	**15.2**	**15.3**	**15.3**	**15.4**	**15.5**	**15.5**	**15.6**	**15.6**	**15.7**
Variable O&M (CAD/MWh)	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**	**64.9**

Note: All values in CAD and shown in 2022 dollars

Sargent & Lundy

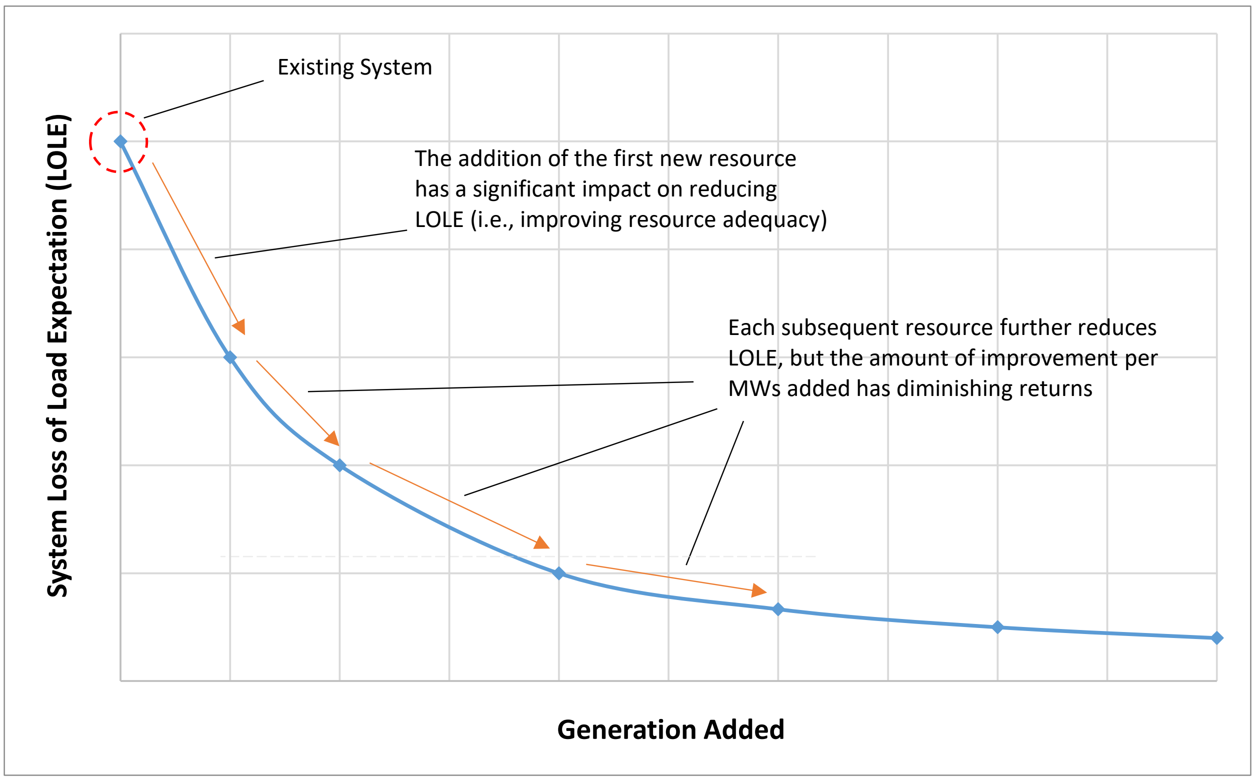
APPENDIX C. EFFECTIVE LOAD CARRYING CAPABILITY INTRODUCTION

The technical characteristics of different generators can result in the generators providing varying levels of contributions towards resource adequacy. To effectively evaluate different technologies and their contributions towards improving system resource adequacy, a concept called the Effective Load Carrying Capability (ELCC) of a generator is used. In simple terms, the ELCC of a generator reflects how much the generator is able to contribute towards system resource adequacy (in the case of Maritime Electric, the "system" is the entire Maritimes Area, including Nova Scotia, New Brunswick, and the northern tip of Maine). As a single measure, the ELCC allows for quick comparison of resource adequacy contributions of different generators. The use of ELCC as a measure to quantify a generator's contributions towards resource adequacy has increased with the growth in renewable generators, such as solar, wind, and other similar generation technologies, since the variable generation profiles of these generators makes it more of a complex process to quantify the contributions of these generators towards serving system load.

The ELCC of a generator can vary based on a number of variables, including the dispatchability characteristics of the generator. For example, if generation were needed to meet load in the evening, a stand-alone solar power plant would have a lower overall ELCC than a solar power plant paired with an energy storage system. This is due simply to the fact that the stand-alone solar power plant would not be capable of generating much electricity in the evening (since the sun would have nearly set at this time), while the storage system paired to the other solar power plant likely could generate electricity in the evening (provided the storage is sufficiently charged). ELCC will vary from one planning region to another because load and generation characteristics change from region to region.

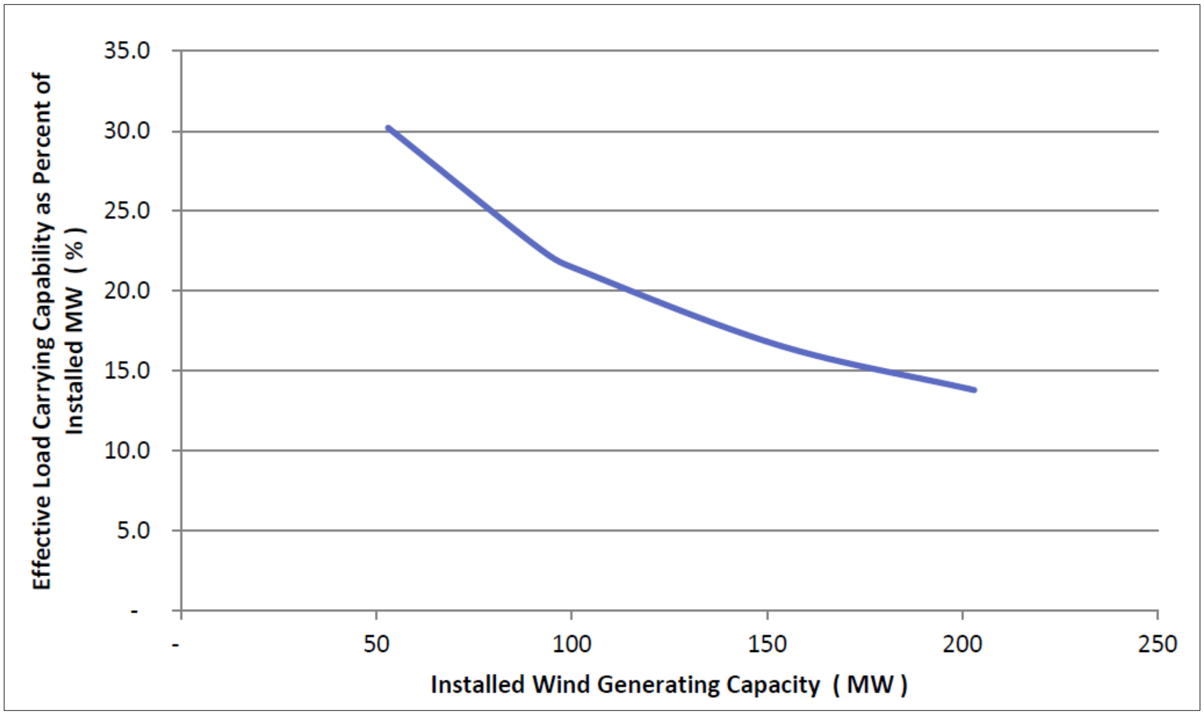
ELCC is typically expressed as a percentage of what could be provided by a "perfect generator", or a generator that would be available to dispatch every hour of the day, all days of the year. For example, a 100-MW wind generator with an ELCC of 25% would help improve system resource adequacy by an equal amount as a 25 MW perfect generator. An equivalent way to view ELCC is to consider how much system load could be increased with the additional generator such that the system resource adequacy level prior to adding the generator would be equivalent to the resource adequacy level after adding the generator. For example, consider a system with a loss of load expectation (LOLE) or equal to 0.10 days/year. A 100 MW wind power plant is added to the system, resulting in the system LOLE to drop to 0.09 days/year. It was then observed that if load were increased by 25 MW, the system LOLE increased back up to 0.10 days/year. In this case, the ELCC of the wind power plant would be equal to 25% (25 MW load increase / 100 MW wind capacity).

It is important to note that the ELCC is a measure of marginal system impact, or the incremental contribution towards resource adequacy. The state of the electrical system from a resource adequacy perspective at the specific time the new generator is added has an impact on the new generator's ELCC. For example, consider the 100 MW wind power plant described above with an ELCC equal to 25% is added to a system. Then, if a second 100 MW of wind is added to the system, the ELCC of the second 100 MW would be less than 25%. The reason for this is because the contributions of additional similar generators towards improving system resource adequacy have diminishing returns. This is illustrated in the following figure, where each dot to the right of the existing system represents additional generators have been added. In the figure, the ELCC of the first new generator would be higher than subsequent generators of similar technology since the amount of LOLE improvement per MW's added reduces with each subsequent addition.



Given that there are costs associated with adding new generators, it is important for system planners to assess the appropriate balance between the desired system LOLE target and system cost, especially since the benefits associated with additional returns diminishes with each additional MW added.

Maritime Electric has calculated the ELCC of wind generation as function of total wind capacity installed. The following figure is taken from Maritime Electric's 2020 Integrated System Plan and illustrates the ELCC of wind. As can be observed in the figure, each additional MW of installed wind capacity on PEI have smaller contributions to resource adequacy.



APPENDIX D. PVSYST SOLAR OUTPUT REPORTS

Version 7.2.12

PVsyst - Simulation report

Grid-Connected System

Project: PEI - Solar PV Feasibility

Variant: Case 1 - 10 MW - Monofacial - Fixed

Unlimited sheds

System power: 14.50 MWp

Prince Edward Island - Canada

Author

Sargent & Lundy LLC (United States)

Project summary

Geographical Site
Prince Edward Island
Canada

Situation

Latitude	46.34 °N
Longitude	-63.41 °W
Altitude	92 m
Time zone	UTC-4

Project settings

Albedo	0.20

Meteo data
Prince Edward Island
Meteonorm 8.0 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System
Simulation for year no 1

Unlimited sheds

PV Field Orientation
Sheds

tilt	12 °
azimuth	0 °

Near Shadings
Mutual shadings of sheds
Electrical effect

User's needs
Unlimited load (grid)

System information

PV Array

Nb. of modules	25216 units
Pnom total	14.50 MWp

Inverters

Nb. of units	13 units
Pnom total	10.92 MWac
Grid power limit	10000 kWac
Grid lim. Pnom ratio	1.450

Results summary

Produced Energy	17 GWh/year	Specific production	1162 kWh/kWp/year	Perf. Ratio PR	86.98 %
Apparent energy	17774 MVAh				

Table of contents

General parameters

Grid-Connected System

Unlimited sheds

PV Field Orientation

Orientation		Sheds configuration		Models used	
Sheds		Nb. of sheds	200 units	Transposition	Perez
tilt	12 °	Unlimited sheds		Diffuse	Perez, Meteonorm
azimuth	0 °	**Sizes**		Circumsolar	separate
		Sheds spacing	5.58 m		
		Collector width	3.91 m		
		Ground Cov. Ratio (GCR)	70.1 %		
		Shading limit angle			
		Limit profile angle	24.8 °		
		Shadings electrical effect			
		Cell size	15.6 cm		
		Strings in width	3 units		

Horizon		Near Shadings	User's needs
Average Height	2.5 °	Mutual shadings of sheds	Unlimited load (grid)
		Electrical effect	

Grid injection point

Grid power limitation		Power factor	
Active Power	10000 kWac	Cos(phi) (leading)	0.950
Pnom ratio	1.450		

PV Array Characteristics

PV module		Inverter	
Manufacturer	Canadian Solar Inc.	Manufacturer	TMEIC
Model	CS7L-575MB-AG 1500V	Model	Solar Ware- PVU-L0840GR
(Custom parameters definition)		(Custom parameters definition)	
Unit Nom. Power	575 Wp	Unit Nom. Power	840 kWac
Number of PV modules	25216 units	Number of inverters	13 units
Nominal (STC)	14.50 MWp	Total power	10920 kWac
Modules	788 Strings x 32 In series	Operating voltage	915-1300 V
At operating cond. (50°C)		Pnom ratio (DC:AC)	1.33
Pmpp	13.32 MWp		
U mpp	969 V		
I mpp	13747 A		

Total PV power		Total inverter power	
Nominal (STC)	14499 kWp	Total power	10920 kWac
Total	25216 modules	Number of inverters	13 units
Module area	71364 m²	Pnom ratio	1.33

Array losses

Array Soiling Losses

Average loss Fraction 2.5 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5.0%	7.0%	5.0%	2.5%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	2.0%	3.0%

Thermal Loss factor		DC wiring losses		LID - Light Induced Degradation	
Module temperature according to irradiance		Global array res.	1.2 mΩ	Loss Fraction	1.0 %
Uc (const)	29.0 W/m²K	Loss Fraction	1.5 % at STC		
Uv (wind)	0.0 W/m²K/m/s				

Array losses

Module Quality Loss
Loss Fraction -0.4 %

Module mismatch losses
Loss Fraction 0.8 % at MPP

Strings Mismatch loss
Loss Fraction 0.1 %

Module average degradation
Year no 1
Loss factor 0.5 %/year

Mismatch due to degradation
Imp RMS dispersion 0 %/year
Vmp RMS dispersion 0 %/year

IAM loss factor
Incidence effect (IAM): User defined profile

20°	40°	60°	65°	70°	75°	80°	85°	90°
1.000	1.000	1.000	0.990	0.960	0.920	0.840	0.720	0.000

System losses

Auxiliaries loss
Proportionnal to Power 3.0 W/kW
0.0 kW from Power thresh.

AC wiring losses

Inv. output line up to MV transfo
Inverter voltage 630 Vac tri
Loss Fraction 0.04 % at STC

Inverter: Solar Ware- PVU-L0840GR
Wire section (13 Inv.) Copper 13 x 3 x 700 mm²
Average wires length 5 m

MV line up to HV Transfo
MV Voltage 34.5 kV
Average each inverter
Wires Copper 3 x 95 mm²
Length 6300 m
Loss Fraction 0.55 % at STC

HV line up to Injection
HV line voltage 138 kV
Wires Copper 3 x 16 mm²
Length 1135 m
Loss Fraction 0.11 % at STC

AC losses in transformers

MV transfo
Medium voltage 34.5 kV

Operating losses at STC
Nominal power at STC 14277 kVA
Iron loss (24/24 Connexion) 4.76 kW/Inv.
Loss Fraction 0.10 % at STC
Coils equivalent resistance 3 x 0.67 mΩ/inv.
Loss Fraction 0.80 % at STC

HV transfo
Grid voltage 138 kV

Transformer from Datasheets
Nominal power 15000 kVA
Iron loss 7.00 kVA
Loss Fraction 0.05 % of PNom
Copper loss 55.00 kVA
Loss Fraction 0.37 % of PNom

Operating losses at STC
Nominal power at STC 14277 kVA
Iron loss (24/24 Connexion) 7.00 kW
Loss Fraction 0.05 % at STC
Coils equivalent resistance 3 x 291.0 mΩ
Loss Fraction 0.35 % at STC

Horizon definition

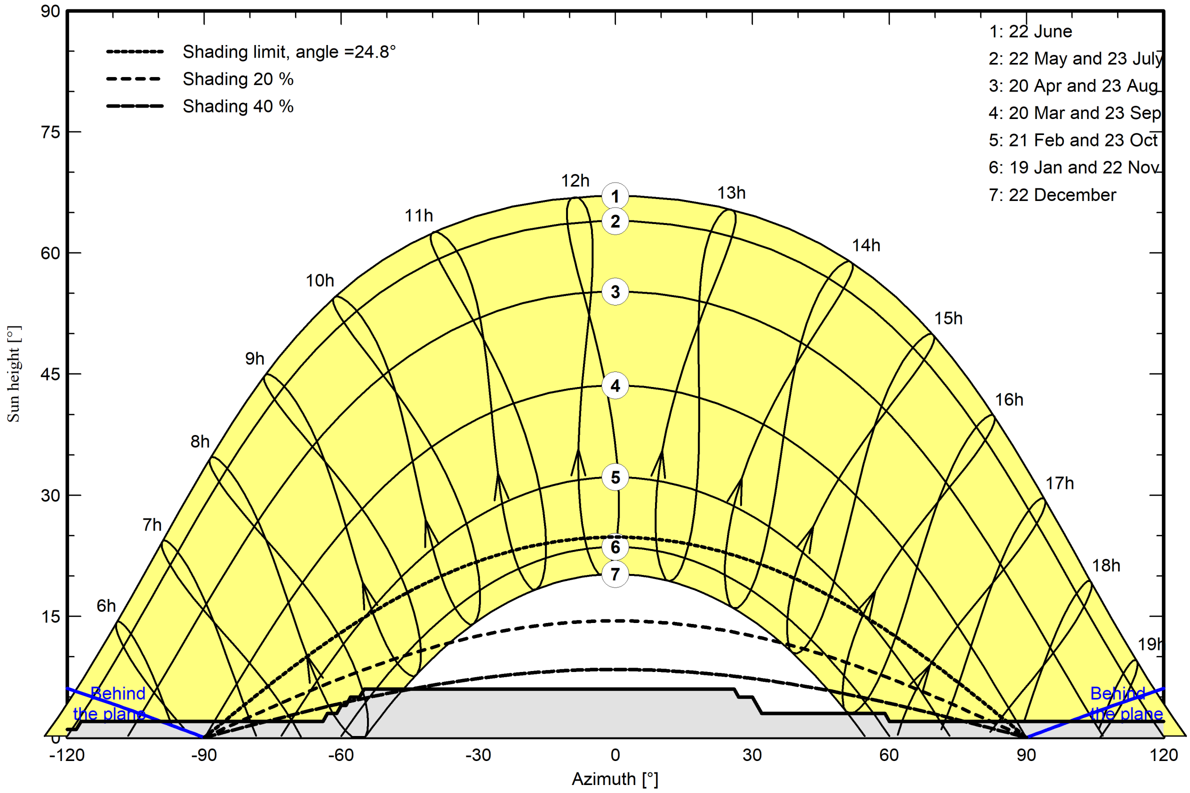
Horizon from Meteonorm web service, lat=46.3396, lon=-63.4083

Average Height	2.5 °	Albedo Factor	0.74
Diffuse Factor	0.98	Albedo Fraction	100 %

Horizon profile

Azimuth [°]	-180	-121	-120	-118	-117	-64	-63	-61	-60	-59	-58	-56
Height [°]	0.0	0.0	1.0	1.0	2.0	2.0	3.0	3.0	4.0	4.0	5.0	5.0
Azimuth [°]	-55	26	27	30	32	59	60	123	124	167	168	179
Height [°]	6.0	6.0	5.0	5.0	3.0	3.0	2.0	2.0	1.0	1.0	0.0	0.0

Sun Paths (Height / Azimuth diagram)

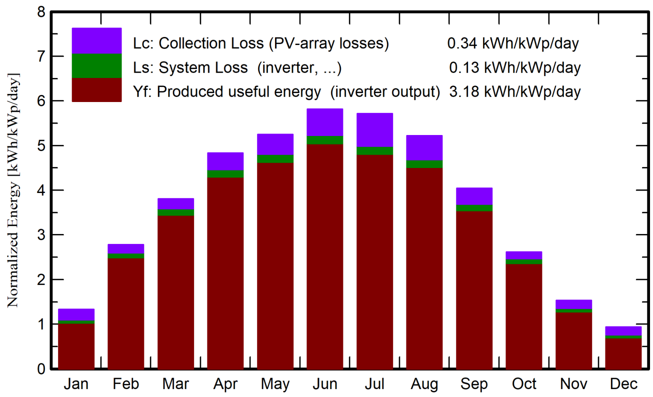


Main results

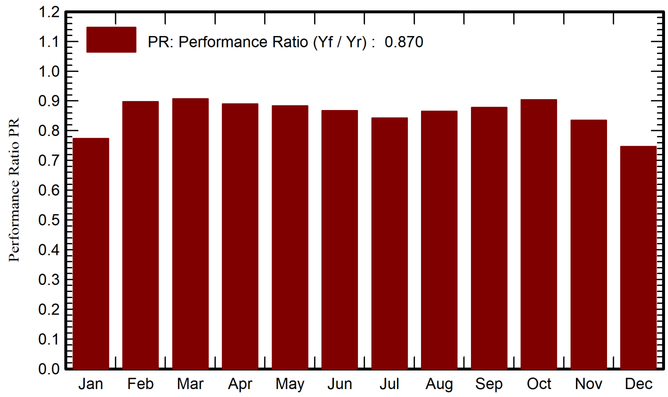
System Production

Produced Energy	17 GWh/year	Specific production	1162 kWh/kWp/year
Apparent energy	17774 MVAh	Performance Ratio PR	86.98 %

Normalized productions (per installed kWp)



Performance Ratio PR



Balances and main results

	GlobHor	DiffHor	T_Amb	GlobInc	GlobEff	EArray	E_Grid	PR
	kWh/m²	kWh/m²	°C	kWh/m²	kWh/m²	GWh	GWh	ratio
January	32.0	17.71	-6.82	41.2	36.3	0.495	0.462	0.774
February	62.4	27.46	-6.83	77.8	70.7	1.057	1.012	0.897
March	102.7	43.95	-2.70	118.0	110.0	1.614	1.551	0.907
April	134.9	66.05	2.96	145.1	138.7	1.944	1.872	0.890
May	158.1	83.23	9.20	162.7	157.9	2.161	2.082	0.883
June	172.5	85.88	14.37	174.5	169.4	2.276	2.195	0.868
July	173.1	78.95	19.48	177.1	172.2	2.244	2.162	0.842
August	153.2	74.50	19.34	162.0	157.4	2.107	2.030	0.865
September	108.5	45.00	14.94	121.4	118.0	1.607	1.544	0.877
October	68.6	33.10	9.31	81.1	78.5	1.111	1.062	0.904
November	36.7	20.26	3.37	46.0	42.9	0.591	0.557	0.835
December	23.0	15.54	-2.53	28.9	25.3	0.343	0.313	0.746
Year	1225.8	591.64	6.25	1335.7	1277.4	17.550	16.844	0.870

Legends

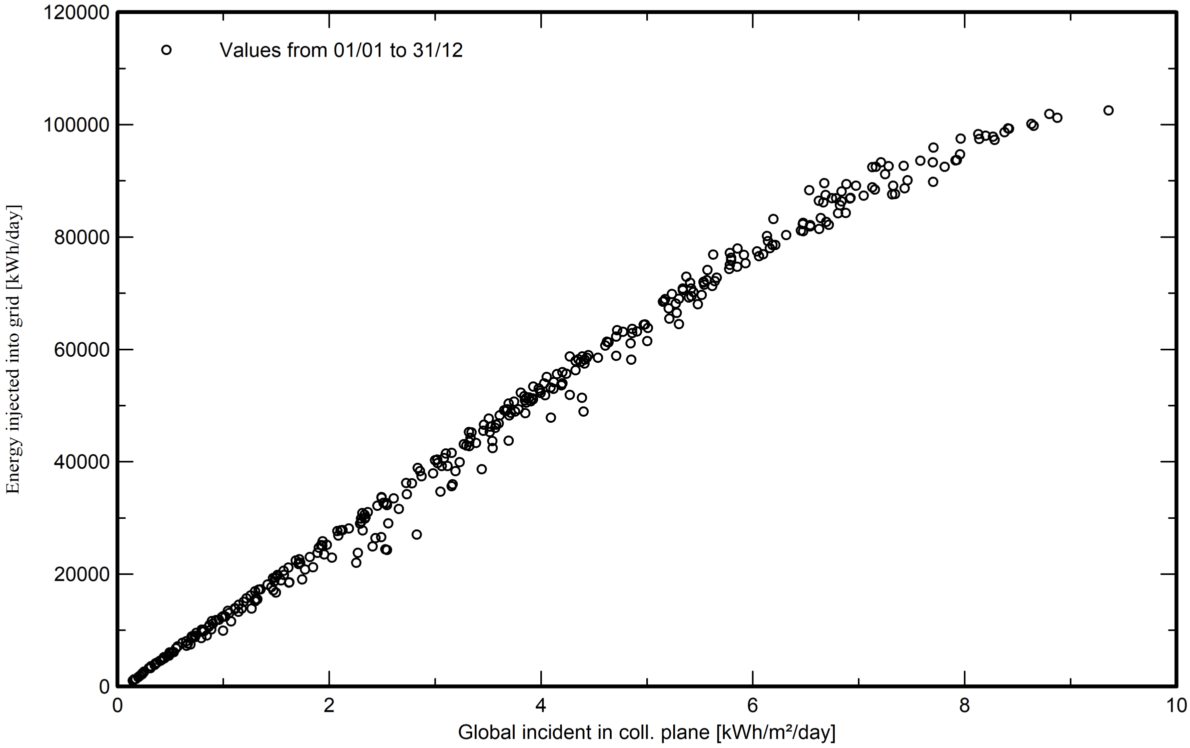
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_Grid	Energy injected into grid
T_Amb	Ambient Temperature	PR	Performance Ratio
GlobInc	Global incident in coll. plane		
GlobEff	Effective Global, corr. for IAM and shadings		

Loss diagram

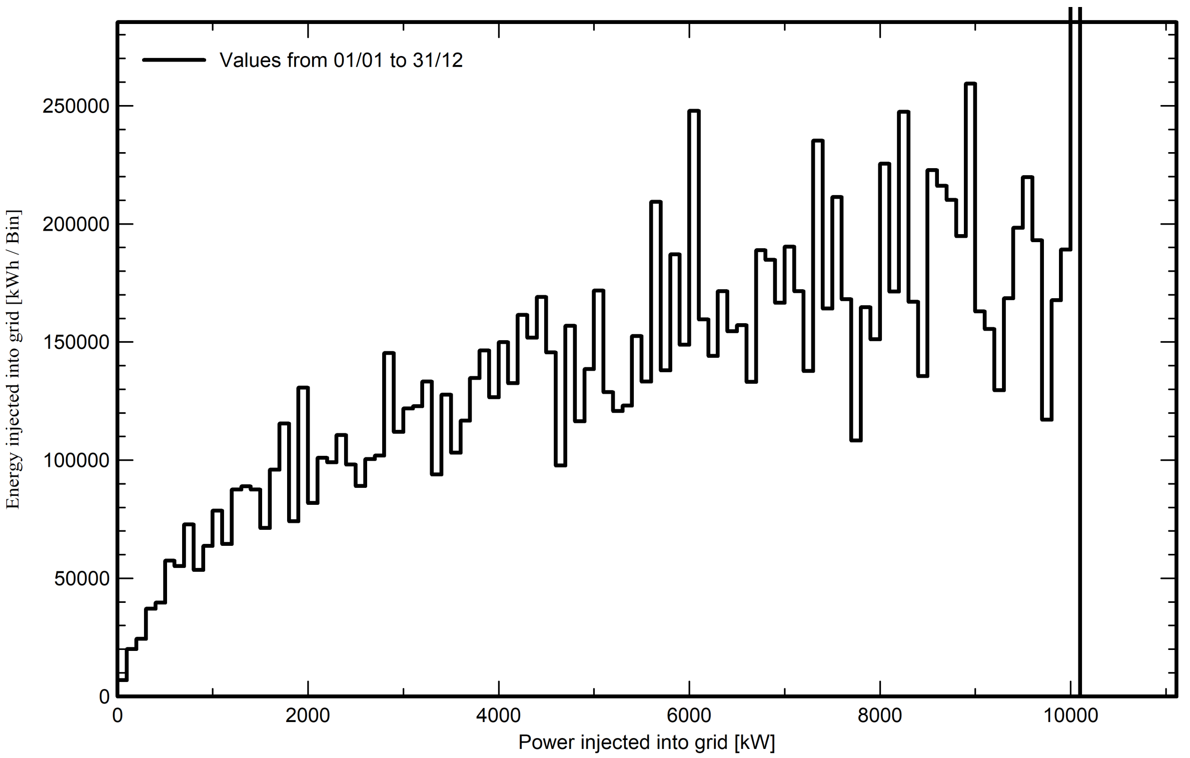
1226 kWh/m²	**Global horizontal irradiation**
+9.0%	**Global incident in coll. plane**
-0.59%	Far Shadings / Horizon
-0.97%	Near Shadings: irradiance loss
-0.81%	IAM factor on global
-2.06%	Soiling loss factor
1277 kWh/m² * 71364 m² coll.	**Effective irradiation on collectors**
efficiency at STC = 20.41%	PV conversion
18.61 GWh	**Array nominal energy (at STC effic.)**
-0.25%	Module Degradation Loss (for year #1)
-0.34%	PV loss due to irradiance level
-0.12%	PV loss due to temperature
-0.78%	Shadings: Electrical Loss , sheds3 strings in width
+0.43%	Module quality loss
-1.00%	LID - Light induced degradation
-0.90%	Mismatch loss, modules and strings
-0.79%	Ohmic wiring loss
17.92 GWh	**Array virtual energy at MPP**
-1.67%	Inverter Loss during operation (efficiency)
-1.02%	Inverter Loss over nominal inv. power
0.00%	Inverter Loss due to max. input current
0.00%	Inverter Loss over nominal inv. voltage
0.00%	Inverter Loss due to power threshold
0.00%	Inverter Loss due to voltage threshold
-0.03%	Night consumption
17.44 GWh	**Available Energy at Inverter Output**
-0.30%	Auxiliaries (fans, other)
-0.02%	AC ohmic loss
-1.14%	Medium voltage transfo loss
-0.26%	MV line ohmic loss
-0.54%	High voltage transfo loss
-0.05%	HV line ohmic loss
-1.12%	Unused energy (grid limitation)
16.84 GWh	**Active Energy injected into grid**
5.67 kVAR	Reactive energy to the grid: Aver. cos(phi) = 0.948
17.77 kVA	**Apparent energy to the grid**

Special graphs

Daily Input/Output diagram



System Output Power Distribution



Version 7.2.12

PVsyst - Simulation report

Grid-Connected System

Project: PEI - Solar PV Feasibility

Variant: Case 2 - 10 MW - Bifacial - Fixed

Unlimited sheds

System power: 14.50 MWp

Prince Edward Island - Canada

Author

Sargent & Lundy LLC (United States)

Project summary

Geographical Site		Situation		Project settings	
Prince Edward Island		Latitude	46.34 °N	Albedo	0.20
Canada		Longitude	-63.41 °W		
		Altitude	92 m		
		Time zone	UTC-4		

Meteo data
Prince Edward Island
Meteonorm 8.0 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System
Simulation for year no 1

Unlimited sheds

PV Field Orientation
Sheds
tilt 12 °
azimuth 0 °

Near Shadings
Mutual shadings of sheds
Electrical effect

User's needs
Unlimited load (grid)

System information

PV Array		Inverters	
Nb. of modules	25216 units	Nb. of units	13 units
Pnom total	14.50 MWp	Pnom total	10.92 MWac
		Grid power limit	10000 kWac
		Grid lim. Pnom ratio	1.450

Results summary

Produced Energy	17 GWh/year	Specific production	1203 kWh/kWp/year	Perf. Ratio PR	90.06 %
Apparent energy	18404 MVAh				

Table of contents

General parameters

Grid-Connected System

Unlimited sheds

PV Field Orientation

Orientation

Sheds	
tilt	12 °
azimuth	0 °

Sheds configuration

Nb. of sheds	200 units
Unlimited sheds	

Sizes

Sheds spacing	5.58 m
Collector width	3.91 m
Ground Cov. Ratio (GCR)	70.1 %

Shading limit angle

Limit profile angle	24.8 °

Shadings electrical effect

Cell size	15.6 cm
Strings in width	3 units

Models used

Transposition	Perez
Diffuse	Perez, Meteonorm
Circumsolar	separate

Horizon

Average Height 2.5 °

Near Shadings

Mutual shadings of sheds
Electrical effect

User's needs

Unlimited load (grid)

Bifacial system

Model 2D Calculation
unlimited sheds

Bifacial model geometry

Sheds spacing	5.58 m
Sheds width	3.91 m
Limit profile angle	24.8 °
GCR	70.1 %
Height above ground	2.00 m

Bifacial model definitions

Ground albedo average	0.34
Bifaciality factor	70 %
Rear shading factor	5.0 %
Rear mismatch loss	10.0 %
Shed transparent fraction	4.0 %

Monthly ground albedo values

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year
0.50	0.60	0.50	0.40	0.20	0.20	0.20	0.20	0.20	0.20	0.40	0.50	0.34

Grid injection point

Grid power limitation

Active Power	10000 kWac
Pnom ratio	1.450

Power factor

Cos(phi) (leading)	0.950

PV Array Characteristics

PV module

Manufacturer	Canadian Solar Inc.
Model	CS7L-575MB-AG 1500V
(Custom parameters definition)	
Unit Nom. Power	575 Wp
Number of PV modules	25216 units
Nominal (STC)	14.50 MWp
Modules	788 Strings x 32 In series

At operating cond. (50°C)

Pmpp	13.32 MWp
U mpp	969 V
I mpp	13747 A

Inverter

Manufacturer	TMEIC
Model	Solar Ware- PVU-L0840GR
(Custom parameters definition)	
Unit Nom. Power	840 kWac
Number of inverters	13 units
Total power	10920 kWac
Operating voltage	915-1300 V
Pnom ratio (DC:AC)	1.33

PV Array Characteristics

Total PV power

Nominal (STC)	14499 kWp
Total	25216 modules
Module area	71364 m²

Total inverter power

Total power	10920 kWac
Number of inverters	13 units
Pnom ratio	1.33

Array losses

Array Soiling Losses
Average loss Fraction 2.3 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
4.5%	6.0%	4.5%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.5%	2.5%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 1.2 mΩ
Loss Fraction 1.5 % at STC

LID - Light Induced Degradation
Loss Fraction 1.0 %

Module Quality Loss
Loss Fraction -0.4 %

Module mismatch losses
Loss Fraction 0.8 % at MPP

Strings Mismatch loss
Loss Fraction 0.1 %

Module average degradation
Year no 1
Loss factor 0.45 %/year

Mismatch due to degradation
Imp RMS dispersion 0 %/year
Vmp RMS dispersion 0 %/year

IAM loss factor
Incidence effect (IAM): User defined profile

20°	40°	60°	65°	70°	75°	80°	85°	90°
1.000	1.000	1.000	0.990	0.960	0.920	0.840	0.720	0.000

System losses

Auxiliaries loss
Proportionnal to Power 3.0 W/kW
0.0 kW from Power thresh.

AC wiring losses

Inv. output line up to MV transfo
Inverter voltage 630 Vac tri
Loss Fraction 0.04 % at STC

Inverter: Solar Ware- PVU-L0840GR
Wire section (13 Inv.) Copper 13 x 3 x 700 mm²
Average wires length 5 m

MV line up to HV Transfo
MV Voltage 34.5 kV
Average each inverter
Wires Copper 3 x 95 mm²
Length 5700 m
Loss Fraction 0.50 % at STC

HV line up to Injection
HV line voltage 138 kV
Wires Copper 3 x 16 mm²
Length 1024 m
Loss Fraction 0.10 % at STC

AC losses in transformers

MV transfo

Medium voltage	34.5 kV
Operating losses at STC	
Nominal power at STC	14277 kVA
Iron loss (24/24 Connexion)	4.76 kW/Inv.
Loss Fraction	0.10 % at STC
Coils equivalent resistance	3 x 0.67 mΩ/inv.
Loss Fraction	0.80 % at STC

HV transfo

Grid voltage	138 kV		
Transformer from Datasheets		**Operating losses at STC**	
Nominal power	15000 kVA	Nominal power at STC	14277 kVA
Iron loss	7.00 kVA	Iron loss (24/24 Connexion)	7.00 kW
Loss Fraction	0.05 % of PNom	Loss Fraction	0.05 % at STC
Copper loss	55.00 kVA	Coils equivalent resistance	3 x 291.0 mΩ
Loss Fraction	0.37 % of PNom	Loss Fraction	0.35 % at STC

Horizon definition

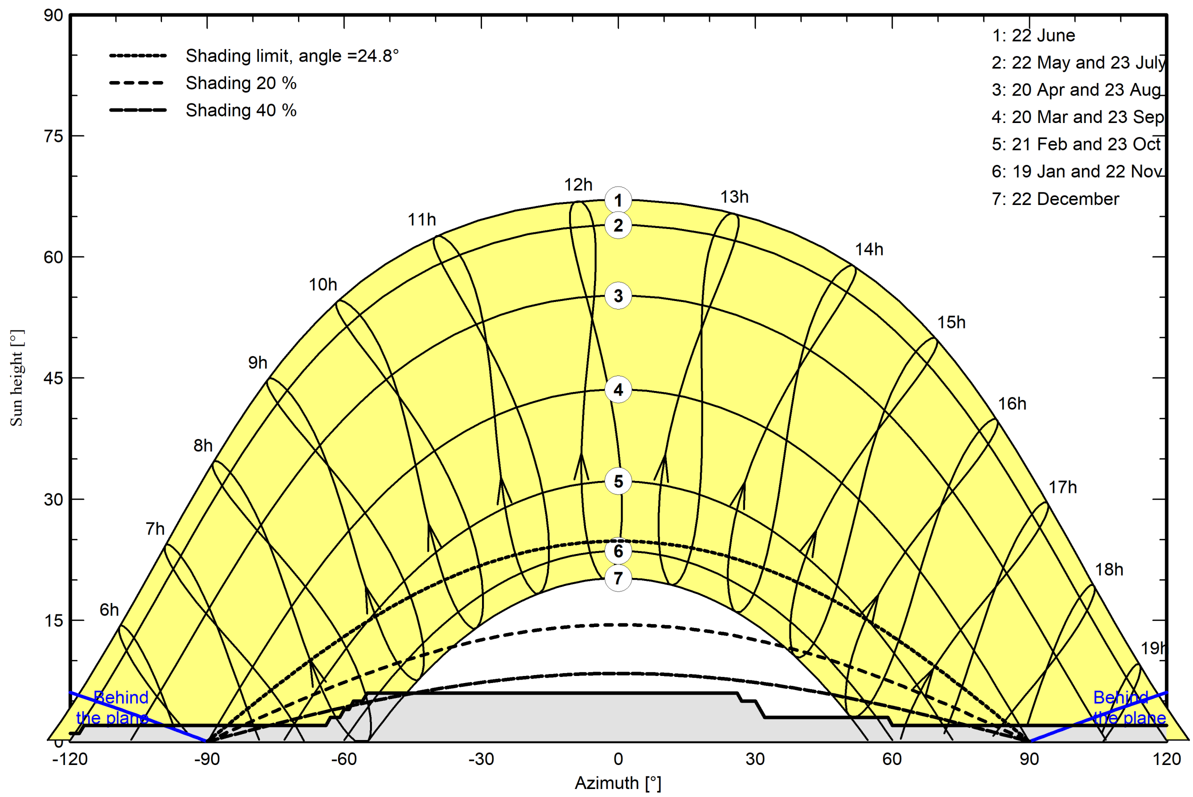
Horizon from Meteonorm web service, lat=46.3396, lon=-63.4083

Average Height	2.5 °	Albedo Factor	0.74
Diffuse Factor	0.98	Albedo Fraction	100 %

Horizon profile

Azimuth [°]	-180	-121	-120	-118	-117	-64	-63	-61	-60	-59	-58	-56
Height [°]	0.0	0.0	1.0	1.0	2.0	2.0	3.0	3.0	4.0	4.0	5.0	5.0
Azimuth [°]	-55	26	27	30	32	59	60	123	124	167	168	179
Height [°]	6.0	6.0	5.0	5.0	3.0	3.0	2.0	2.0	1.0	1.0	0.0	0.0

Sun Paths (Height / Azimuth diagram)

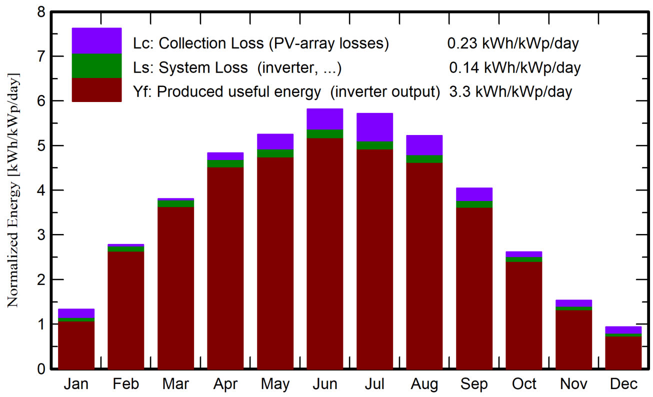


Main results

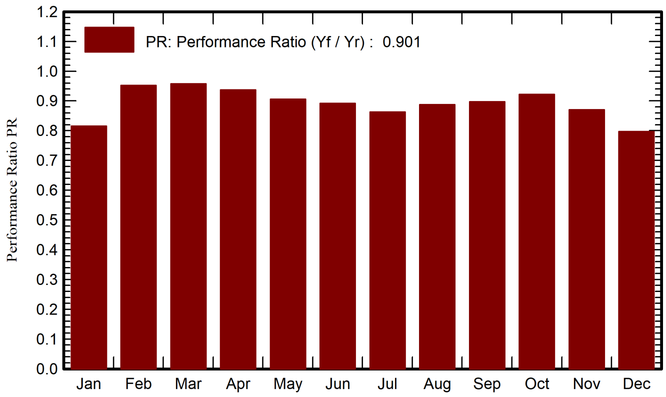
System Production

Produced Energy	17 GWh/year	Specific production	1203 kWh/kWp/year
Apparent energy	18404 MVAh	Performance Ratio PR	90.06 %

Normalized productions (per installed kWp)



Performance Ratio PR



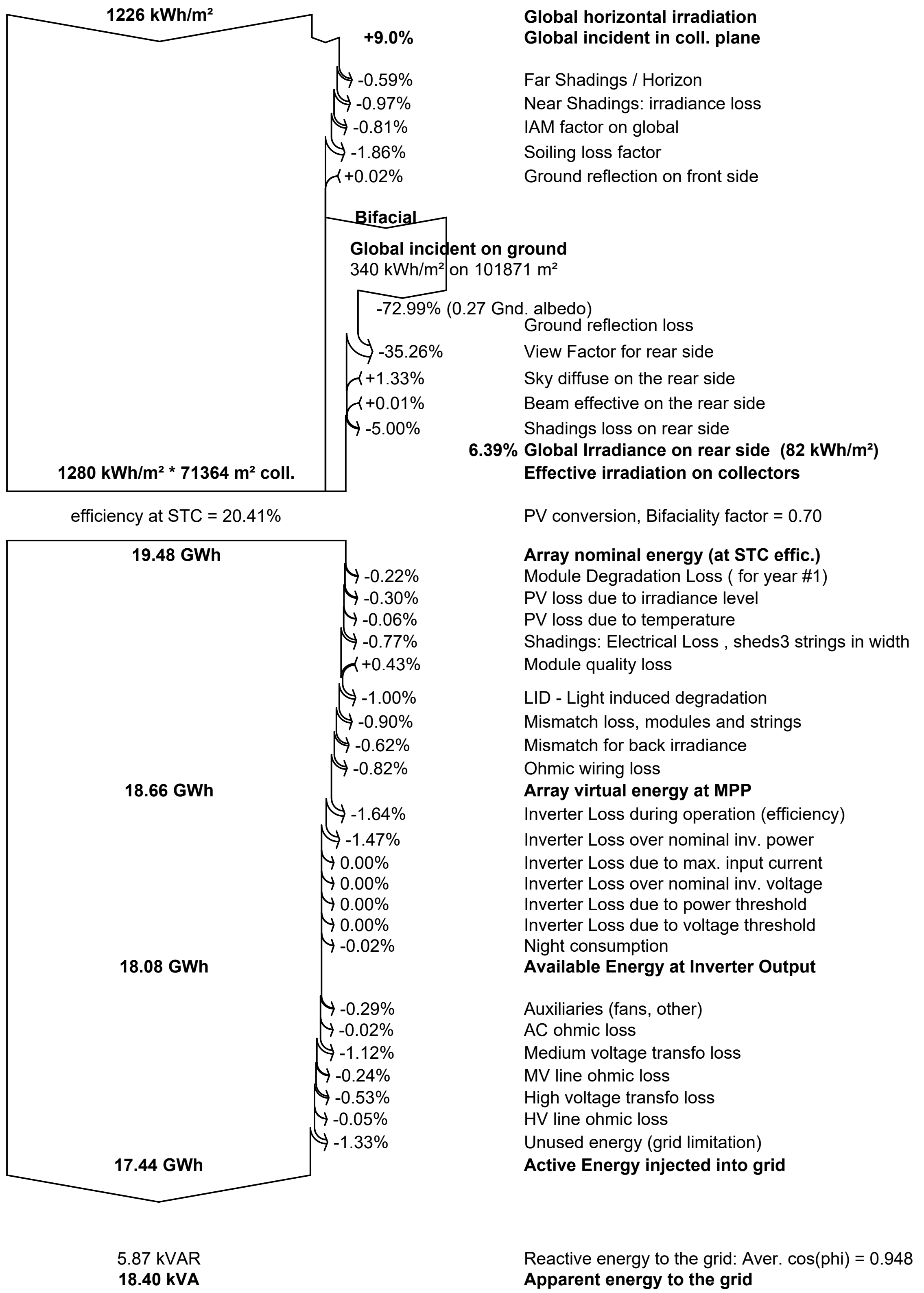
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray GWh	E_Grid GWh	PR ratio
January	32.0	17.71	-6.82	41.2	36.5	0.520	0.487	0.816
February	62.4	27.46	-6.83	77.8	71.5	1.120	1.074	0.952
March	102.7	43.95	-2.70	118.0	110.7	1.704	1.638	0.958
April	134.9	66.05	2.96	145.1	139.5	2.045	1.970	0.937
May	158.1	83.23	9.20	162.7	157.9	2.217	2.137	0.906
June	172.5	85.88	14.37	174.5	169.5	2.339	2.256	0.892
July	173.1	78.95	19.48	177.1	172.2	2.299	2.217	0.863
August	153.2	74.50	19.34	162.0	157.4	2.161	2.084	0.887
September	108.5	45.00	14.94	121.4	118.0	1.643	1.579	0.897
October	68.6	33.10	9.31	81.1	78.5	1.133	1.084	0.922
November	36.7	20.26	3.37	46.0	43.2	0.615	0.580	0.870
December	23.0	15.54	-2.53	28.9	25.4	0.364	0.335	0.797
Year	1225.8	591.63	6.25	1335.7	1280.3	18.159	17.442	0.901

Legends

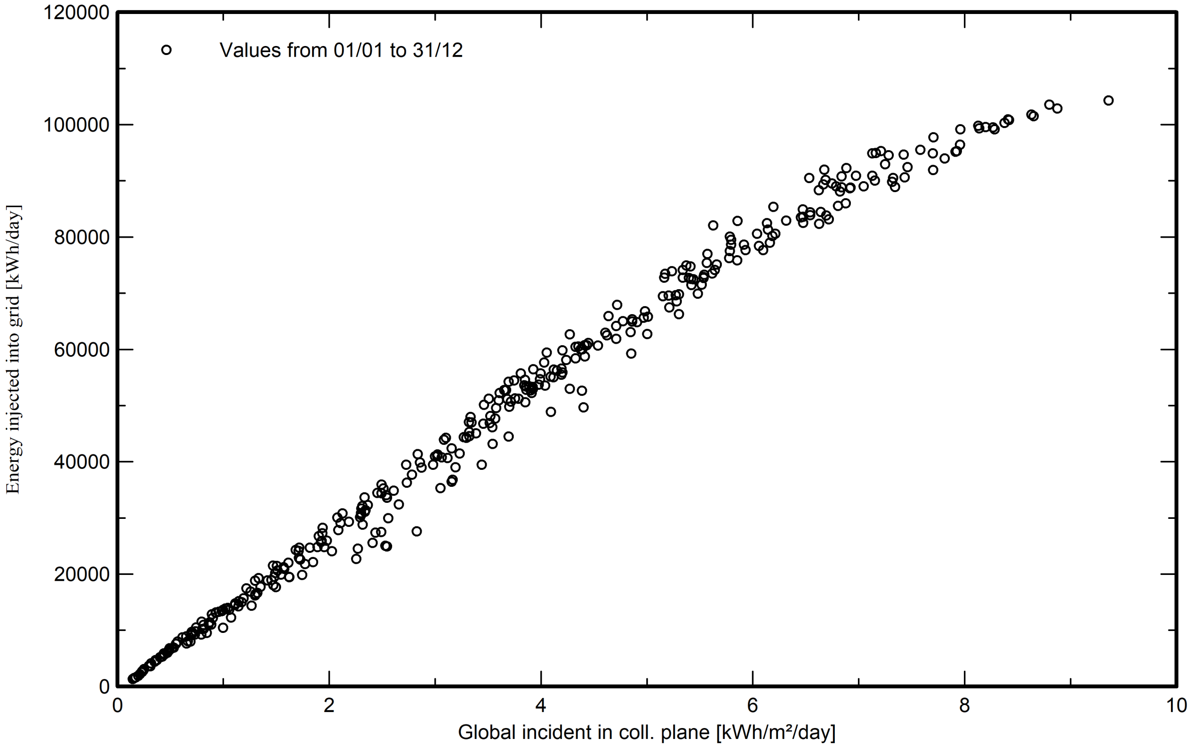
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_Grid	Energy injected into grid
T_Amb	Ambient Temperature	PR	Performance Ratio
GlobInc	Global incident in coll. plane		
GlobEff	Effective Global, corr. for IAM and shadings		

Loss diagram

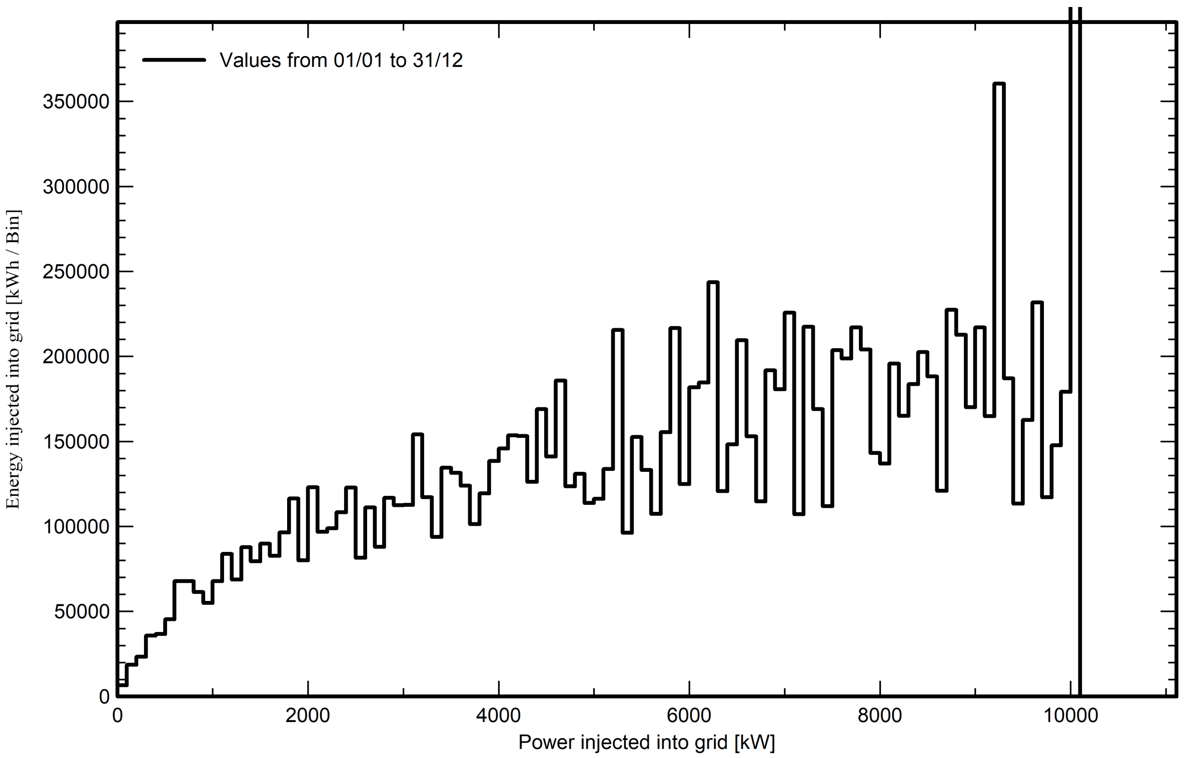


Special graphs

Daily Input/Output diagram



System Output Power Distribution



Version 7.2.12

PVsyst - Simulation report

Grid-Connected System

Project: PEI - Solar PV Feasibility

Variant: Case 3 - 10 MW - Monofacial - SAT

Unlimited Trackers with backtracking

System power: 13.01 MWp

Prince Edward Island - Canada

Author

Sargent & Lundy LLC (United States)

Project summary

Geographical Site		**Situation**		**Project settings**	
Prince Edward Island		Latitude	46.34 °N	Albedo	0.20
Canada		Longitude	-63.41 °W		
		Altitude	92 m		
		Time zone	UTC-4		

Meteo data
Prince Edward Island
Meteonorm 8.0 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System
Simulation for year no 1

Unlimited Trackers with backtracking

PV Field Orientation
Orientation
Tracking horizontal axis

Tracking algorithm
Astronomic calculation
Backtracking activated

Near Shadings
No Shadings

System information

PV Array		**Inverters**	
Nb. of modules	22624 units	Nb. of units	13 units
Pnom total	13.01 MWp	Pnom total	10.92 MWac
		Grid power limit	10000 kWac
		Grid lim. Pnom ratio	1.301

User's needs
Unlimited load (grid)

Results summary

Produced Energy	18 GWh/year	Specific production	1406 kWh/kWp/year	Perf. Ratio PR	88.26 %
Apparent energy	19294 MVAh				

Table of contents

General parameters

Grid-Connected System | **Unlimited Trackers with backtracking**

PV Field Orientation

Orientation
Tracking horizontal axis

Tracking algorithm
Astronomic calculation
Backtracking activated

Backtracking strategy

Nb. of trackers	200 units
Unlimited trackers	
Sizes	
Tracker Spacing	6.21 m
Collector width	2.17 m
Ground Cov. Ratio (GCR)	35.0 %
Phi min / max.	-/+ 52.0 °
Backtracking limit angle	
Phi limits	+/- 69.4 °
Shadings electrical effect	
Cell size	15.6 cm
Strings in width	3 units

Models used

Transposition	Perez
Diffuse	Perez, Meteonorm
Circumsolar	separate

Horizon
Average Height 2.5 °

Near Shadings
No Shadings

User's needs
Unlimited load (grid)

Grid injection point

Grid power limitation

Active Power	10000 kWac
Pnom ratio	1.301

Power factor
Cos(phi) (leading) 0.950

PV Array Characteristics

PV module

Manufacturer	Canadian Solar Inc.
Model	CS7L-575MB-AG 1500V
(Custom parameters definition)	
Unit Nom. Power	575 Wp
Number of PV modules	22624 units
Nominal (STC)	13.01 MWp
Modules	707 Strings x 32 In series
At operating cond. (50°C)	
Pmpp	11.95 MWp
U mpp	969 V
I mpp	12334 A

Inverter

Manufacturer	TMEIC
Model	Solar Ware- PVU-L0840GR
(Custom parameters definition)	
Unit Nom. Power	840 kWac
Number of inverters	13 units
Total power	10920 kWac
Operating voltage	915-1300 V
Pnom ratio (DC:AC)	1.19

Total PV power

Nominal (STC)	13009 kWp
Total	22624 modules
Module area	64029 m²

Total inverter power

Total power	10920 kWac
Number of inverters	13 units
Pnom ratio	1.19

Array losses

Array Soiling Losses
Average loss Fraction 1.4 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
2.0%	3.0%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.5%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 1.3 mΩ
Loss Fraction 1.5 % at STC

LID - Light Induced Degradation
Loss Fraction 1.0 %

Module Quality Loss
Loss Fraction -0.2 %

Module mismatch losses
Loss Fraction 0.8 % at MPP

Strings Mismatch loss
Loss Fraction 0.1 %

Module average degradation
Year no 1
Loss factor 0.5 %/year
Mismatch due to degradation
Imp RMS dispersion 0 %/year
Vmp RMS dispersion 0 %/year

IAM loss factor
Incidence effect (IAM): User defined profile

20°	40°	60°	65°	70°	75°	80°	85°	90°
1.000	1.000	1.000	0.990	0.960	0.920	0.840	0.720	0.000

System losses

Auxiliaries loss
Proportionnal to Power 3.0 W/kW
0.0 kW from Power thresh.

AC wiring losses

Inv. output line up to MV transfo
Inverter voltage 630 Vac tri
Loss Fraction 0.04 % at STC
Inverter: Solar Ware- PVU-L0840GR
Wire section (13 Inv.) Copper 13 x 3 x 700 mm²
Average wires length 5 m

MV line up to HV Transfo
MV Voltage 34.5 kV
Average each inverter
Wires Copper 3 x 95 mm²
Length 6300 m
Loss Fraction 0.50 % at STC

HV line up to Injection
HV line voltage 138 kV
Wires Copper 3 x 16 mm²
Length 1135 m
Loss Fraction 0.10 % at STC

AC losses in transformers

MV transfo

Medium voltage	34.5 kV
Operating losses at STC	
Nominal power at STC	12813 kVA
Iron loss (24/24 Connexion)	4.27 kW/Inv.
Loss Fraction	0.10 % at STC
Coils equivalent resistance	3 x 0.74 mΩ/inv.
Loss Fraction	0.80 % at STC

HV transfo

Grid voltage 138 kV

Transformer from Datasheets		**Operating losses at STC**	
Nominal power	15000 kVA	Nominal power at STC	12813 kVA
Iron loss	7.00 kVA	Iron loss (24/24 Connexion)	7.00 kW
Loss Fraction	0.05 % of PNom	Loss Fraction	0.05 % at STC
Copper loss	55.00 kVA	Coils equivalent resistance	3 x 291.0 mΩ
Loss Fraction	0.37 % of PNom	Loss Fraction	0.31 % at STC

Horizon definition

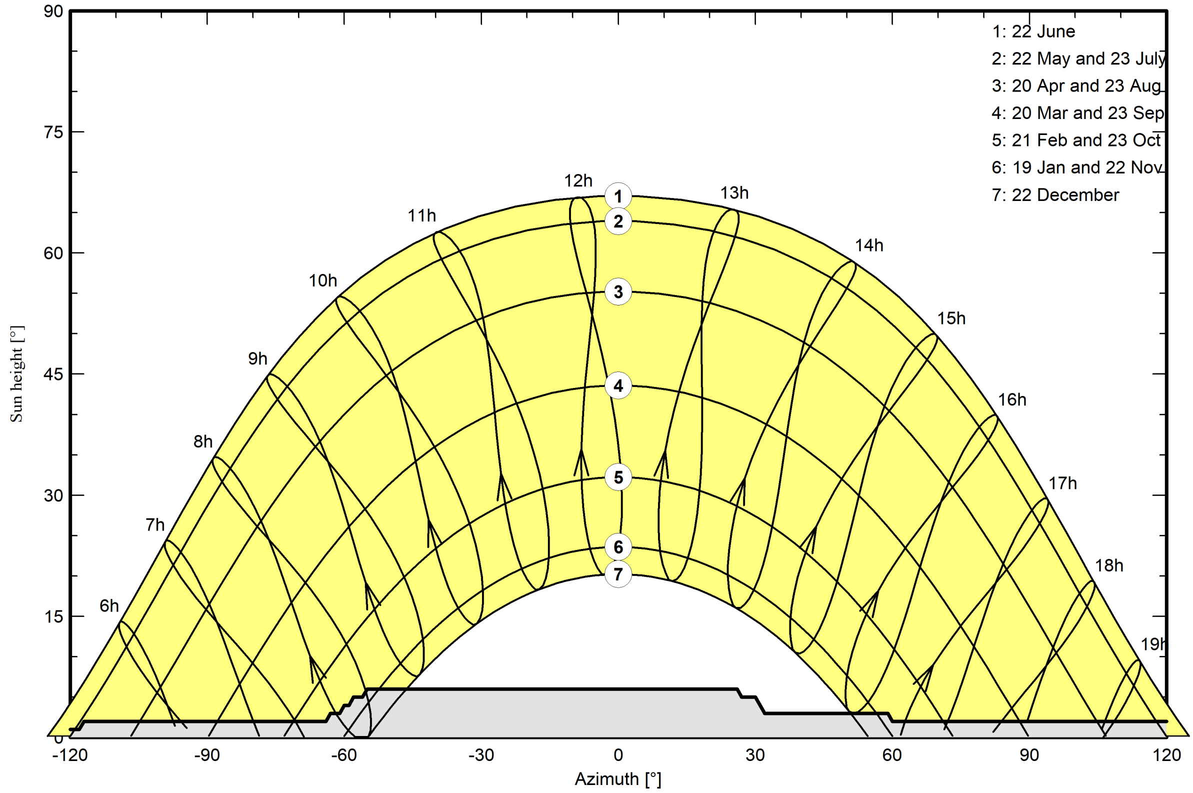
Horizon from Meteonorm web service, lat=46.3396, lon=-63.4083

Average Height	2.5 °	Albedo Factor	0.89
Diffuse Factor	0.97	Albedo Fraction	100 %

Horizon profile

Azimuth [°]	-180	-121	-120	-118	-117	-64	-63	-61	-60	-59	-58	-56
Height [°]	0.0	0.0	1.0	1.0	2.0	2.0	3.0	3.0	4.0	4.0	5.0	5.0
Azimuth [°]	-55	26	27	30	32	59	60	123	124	167	168	179
Height [°]	6.0	6.0	5.0	5.0	3.0	3.0	2.0	2.0	1.0	1.0	0.0	0.0

Sun Paths (Height / Azimuth diagram)

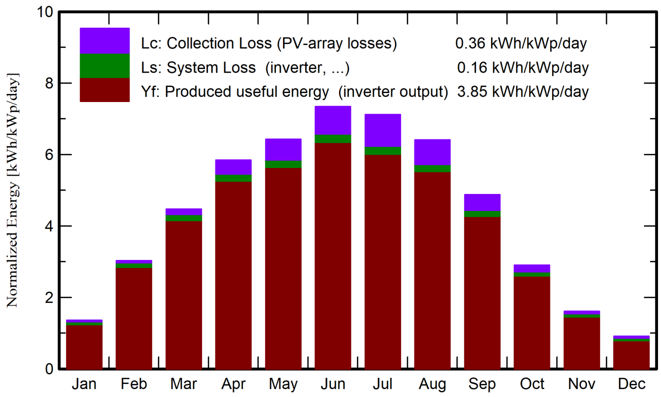


Main results

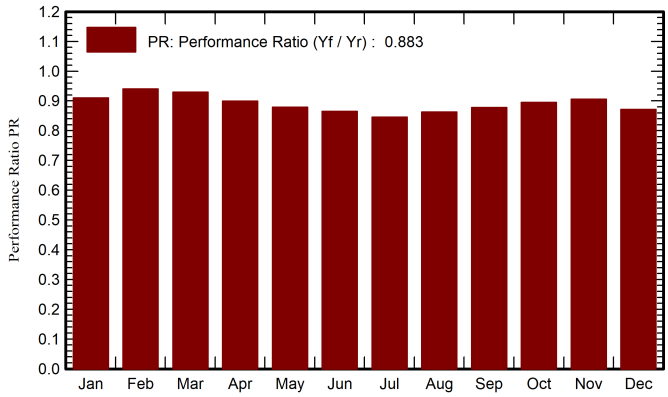
System Production

Produced Energy	18 GWh/year	Specific production	1406 kWh/kWp/year
Apparent energy	19294 MVAh	Performance Ratio PR	88.26 %

Normalized productions (per installed kWp)



Performance Ratio PR



Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray GWh	E_Grid GWh	PR ratio
January	32.0	17.71	-6.82	42.2	39.4	0.532	0.499	0.910
February	62.4	27.46	-6.83	84.8	79.9	1.082	1.037	0.941
March	102.7	43.95	-2.70	138.7	132.1	1.744	1.678	0.930
April	134.9	66.05	2.96	175.4	168.5	2.130	2.052	0.900
May	158.1	83.23	9.20	199.1	191.4	2.361	2.276	0.878
June	172.5	85.88	14.37	220.2	211.8	2.567	2.477	0.865
July	173.1	78.95	19.48	220.7	212.5	2.517	2.427	0.845
August	153.2	74.50	19.34	198.7	191.2	2.311	2.230	0.862
September	108.5	45.00	14.94	146.2	140.7	1.736	1.670	0.878
October	68.6	33.10	9.31	90.1	86.2	1.097	1.049	0.895
November	36.7	20.26	3.37	48.4	46.1	0.604	0.570	0.906
December	23.0	15.54	-2.53	28.3	26.3	0.350	0.321	0.871
Year	1225.8	591.63	6.25	1592.7	1526.2	19.030	18.285	0.883

Legends

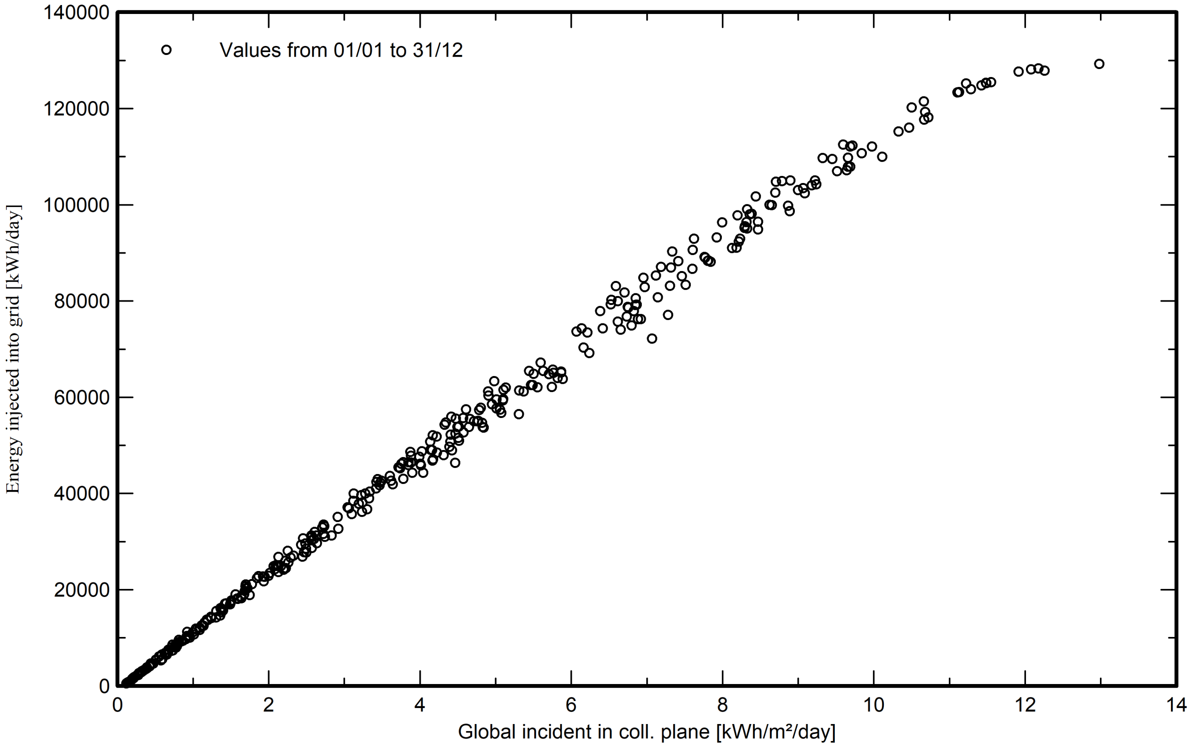
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_Grid	Energy injected into grid
T_Amb	Ambient Temperature	PR	Performance Ratio
GlobInc	Global incident in coll. plane		
GlobEff	Effective Global, corr. for IAM and shadings		

Loss diagram

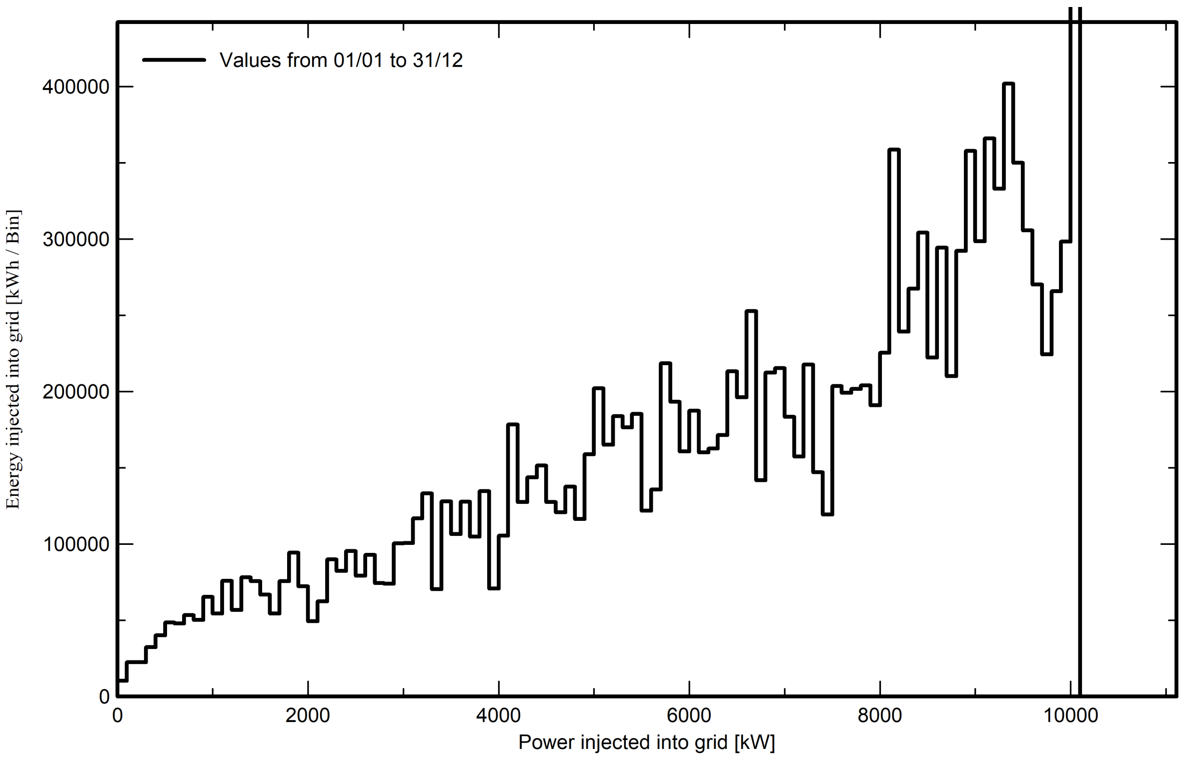
1226 kWh/m²	**Global horizontal irradiation**
+29.9%	**Global incident in coll. plane**
-0.70%	Far Shadings / Horizon
-1.96%	Near Shadings: irradiance loss
-0.34%	IAM factor on global
-1.23%	Soiling loss factor
1526 kWh/m² * 64029 m² coll.	**Effective irradiation on collectors**
efficiency at STC = 20.41%	PV conversion
19.94 GWh	**Array nominal energy (at STC effic.)**
-0.25%	Module Degradation Loss (for year #1)
-0.12%	PV loss due to irradiance level
-0.76%	PV loss due to temperature
0.00%	Shadings: Electrical Loss
+0.20%	Module quality loss
-1.00%	LID - Light induced degradation
-0.90%	Mismatch loss, modules and strings
-0.91%	Ohmic wiring loss
19.21 GWh	**Array virtual energy at MPP**
-1.65%	Inverter Loss during operation (efficiency)
-0.28%	Inverter Loss over nominal inv. power
0.00%	Inverter Loss due to max. input current
0.00%	Inverter Loss over nominal inv. voltage
0.00%	Inverter Loss due to power threshold
0.00%	Inverter Loss due to voltage threshold
-0.02%	Night consumption
18.84 GWh	**Available Energy at Inverter Output**
-0.30%	Auxiliaries (fans, other)
-0.02%	AC ohmic loss
-1.09%	Medium voltage transfo loss
-0.28%	MV line ohmic loss
-0.53%	High voltage transfo loss
-0.06%	HV line ohmic loss
-0.69%	Unused energy (grid limitation)
18.29 GWh	**Active Energy injected into grid**
6.16 kVAR	Reactive energy to the grid: Aver. cos(phi) = 0.948
19.29 kVA	**Apparent energy to the grid**

Special graphs

Daily Input/Output diagram



System Output Power Distribution



Version 7.2.12

PVsyst - Simulation report

Grid-Connected System

Project: PEI - Solar PV Feasibility

Variant: Case 4 - 10 MW - Bifacial - SAT

Unlimited Trackers with backtracking

System power: 13.01 MWp

Prince Edward Island - Canada

Author

Sargent & Lundy LLC (United States)

Project summary

Geographical Site	Situation		Project settings	
Prince Edward Island	Latitude	46.34 °N	Albedo	0.20
Canada	Longitude	-63.41 °W		
	Altitude	92 m		
	Time zone	UTC-4		

Meteo data
Prince Edward Island
Meteonorm 8.0 (1991-2005), Sat=100% - Synthetic

System summary

Grid-Connected System
Simulation for year no 1

Unlimited Trackers with backtracking

PV Field Orientation
Orientation
Tracking horizontal axis

Tracking algorithm
Astronomic calculation
Backtracking activated

Near Shadings
No Shadings

System information

PV Array		Inverters	
Nb. of modules	22624 units	Nb. of units	13 units
Pnom total	13.01 MWp	Pnom total	10.92 MWac
		Grid power limit	10000 kWac
		Grid lim. Pnom ratio	1.301

User's needs
Unlimited load (grid)

Results summary

Produced Energy	20 GWh/year	Specific production	1506 kWh/kWp/year	Perf. Ratio PR	94.58 %
Apparent energy	20673 MVAh				

Table of contents

General parameters

Grid-Connected System — **Unlimited Trackers with backtracking**

PV Field Orientation

Orientation
Tracking horizontal axis

Tracking algorithm
Astronomic calculation
Backtracking activated

Backtracking strategy

Nb. of trackers	200 units
Unlimited trackers	

Sizes

Tracker Spacing	6.21 m
Collector width	2.17 m
Ground Cov. Ratio (GCR)	35.0 %
Phi min / max.	-/+ 52.0 °

Backtracking limit angle

Phi limits	+/- 69.4 °

Shadings electrical effect

Cell size	15.6 cm
Strings in width	3 units

Models used

Transposition	Perez
Diffuse	Perez, Meteonorm
Circumsolar	separate

Horizon
Average Height 2.5 °

Near Shadings
No Shadings

User's needs
Unlimited load (grid)

Bifacial system

Model: 2D Calculation, unlimited trackers

Bifacial model geometry

Tracker Spacing	6.21 m
Tracker width	2.17 m
GCR	35.0 %
Axis height above ground	2.00 m

Bifacial model definitions

Ground albedo average	0.34
Bifaciality factor	70 %
Rear shading factor	2.5 %
Rear mismatch loss	7.5 %
Shed transparent fraction	4.0 %

Monthly ground albedo values

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year
0.50	0.60	0.50	0.40	0.20	0.20	0.20	0.20	0.20	0.20	0.40	0.50	0.34

Grid injection point

Grid power limitation

Active Power	10000 kWac
Pnom ratio	1.301

Power factor

Cos(phi) (leading)	0.950

PV Array Characteristics

PV module

Manufacturer	Canadian Solar Inc.
Model	CS7L-575MB-AG 1500V
(Custom parameters definition)	
Unit Nom. Power	575 Wp
Number of PV modules	22624 units
Nominal (STC)	13.01 MWp
Modules	707 Strings x 32 In series

PV Array Characteristics

PV module		**Inverter**	
At operating cond. (50°C)		Manufacturer	TMEIC
Pmpp	11.95 MWp	Model	Solar Ware- PVU-L0840GR
U mpp	969 V	(Custom parameters definition)	
I mpp	12334 A	Unit Nom. Power	840 kWac
		Number of inverters	13 units
		Total power	10920 kWac
		Operating voltage	915-1300 V
		Pnom ratio (DC:AC)	1.19
Total PV power		**Total inverter power**	
Nominal (STC)	13009 kWp	Total power	10920 kWac
Total	22624 modules	Number of inverters	13 units
Module area	64029 m²	Pnom ratio	1.19

Array losses

Array Soiling Losses
Average loss Fraction 1.3 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
1.5%	2.5%	1.5%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	2.5%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 29.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 1.3 mΩ
Loss Fraction 1.5 % at STC

LID - Light Induced Degradation
Loss Fraction 1.0 %

Module Quality Loss
Loss Fraction -0.4 %

Module mismatch losses
Loss Fraction 0.8 % at MPP

Strings Mismatch loss
Loss Fraction 0.1 %

Module average degradation
Year no 1
Loss factor 0.45 %/year
Mismatch due to degradation
Imp RMS dispersion 0 %/year
Vmp RMS dispersion 0 %/year

IAM loss factor
Incidence effect (IAM): User defined profile

20°	40°	60°	65°	70°	75°	80°	85°	90°
1.000	1.000	1.000	0.990	0.960	0.920	0.840	0.720	0.000

System losses

Auxiliaries loss
Proportionnal to Power 3.0 W/kW
0.0 kW from Power thresh.

AC wiring losses

Inv. output line up to MV transfo

Inverter voltage	630 Vac tri
Loss Fraction	0.04 % at STC
Inverter: Solar Ware- PVU-L0840GR	
Wire section (13 Inv.)	Copper 13 x 3 x 700 mm²
Average wires length	5 m

MV line up to HV Transfo

MV Voltage	34.5 kV
Average each inverter	
Wires	Copper 3 x 95 mm²
Length	6350 m
Loss Fraction	0.50 % at STC

HV line up to Injection

HV line voltage	138 kV
Wires	Copper 3 x 16 mm²
Length	1141 m
Loss Fraction	0.10 % at STC

AC losses in transformers

MV transfo

Medium voltage	34.5 kV
Operating losses at STC	
Nominal power at STC	12813 kVA
Iron loss (24/24 Connexion)	4.27 kW/Inv.
Loss Fraction	0.10 % at STC
Coils equivalent resistance	3 x 0.74 mΩ/inv.
Loss Fraction	0.80 % at STC

HV transfo

Grid voltage	138 kV

Transformer from Datasheets

Nominal power	15000 kVA
Iron loss	7.00 kVA
Loss Fraction	0.05 % of PNom
Copper loss	55.00 kVA
Loss Fraction	0.37 % of PNom

Operating losses at STC

Nominal power at STC	12813 kVA
Iron loss (24/24 Connexion)	7.00 kW
Loss Fraction	0.05 % at STC
Coils equivalent resistance	3 x 291.0 mΩ
Loss Fraction	0.31 % at STC

Horizon definition

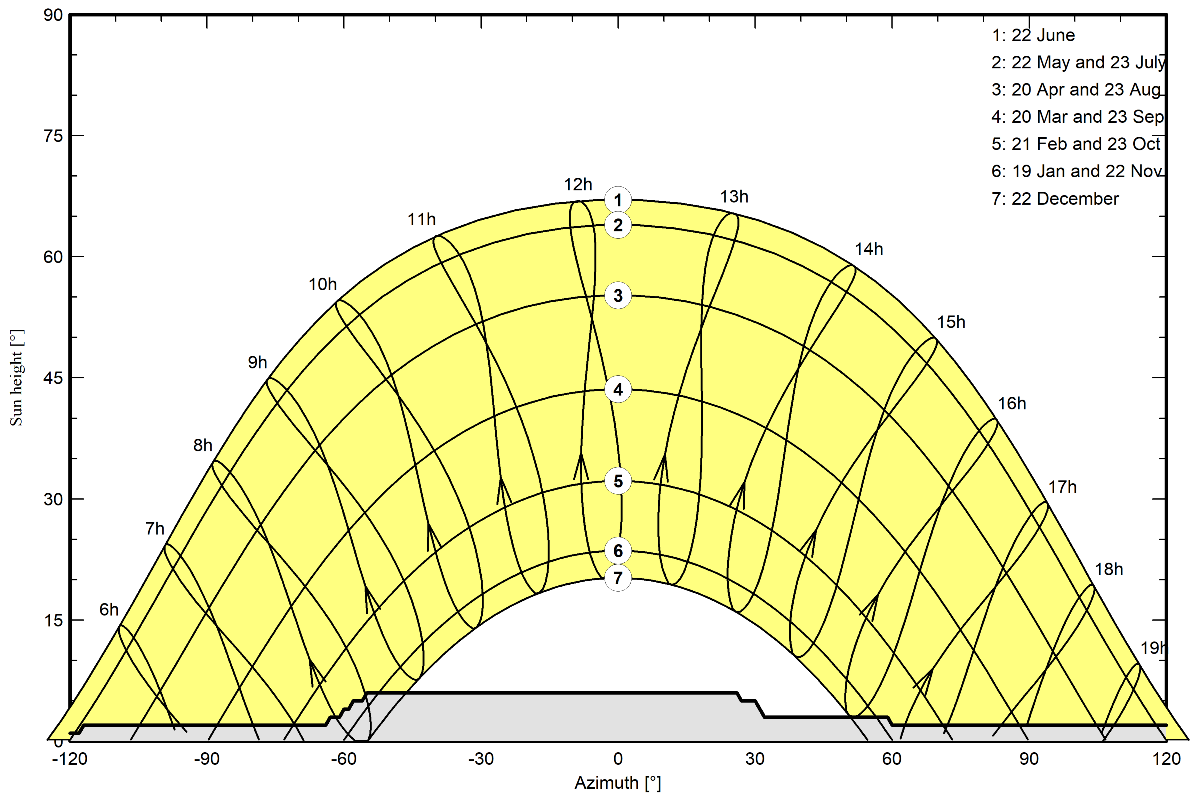
Horizon from Meteonorm web service, lat=46.3396, lon=-63.4083

Average Height	2.5 °	Albedo Factor	0.89
Diffuse Factor	0.97	Albedo Fraction	100 %

Horizon profile

Azimuth [°]	-180	-121	-120	-118	-117	-64	-63	-61	-60	-59	-58	-56
Height [°]	0.0	0.0	1.0	1.0	2.0	2.0	3.0	3.0	4.0	4.0	5.0	5.0
Azimuth [°]	-55	26	27	30	32	59	60	123	124	167	168	179
Height [°]	6.0	6.0	5.0	5.0	3.0	3.0	2.0	2.0	1.0	1.0	0.0	0.0

Sun Paths (Height / Azimuth diagram)

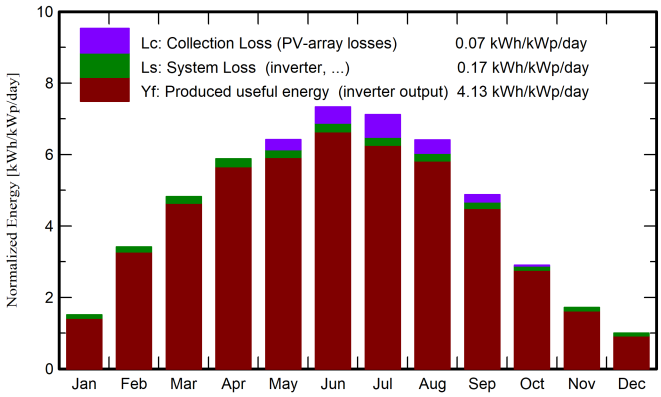


Main results

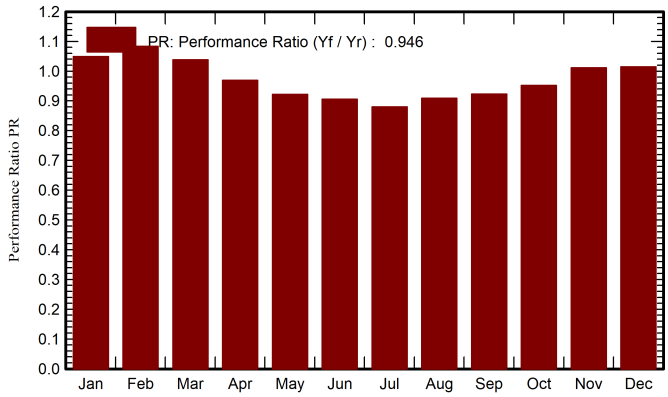
System Production

Produced Energy	20 GWh/year	Specific production	1506 kWh/kWp/year
Apparent energy	20673 MVAh	Performance Ratio PR	94.58 %

Normalized productions (per installed kWp)



Performance Ratio PR



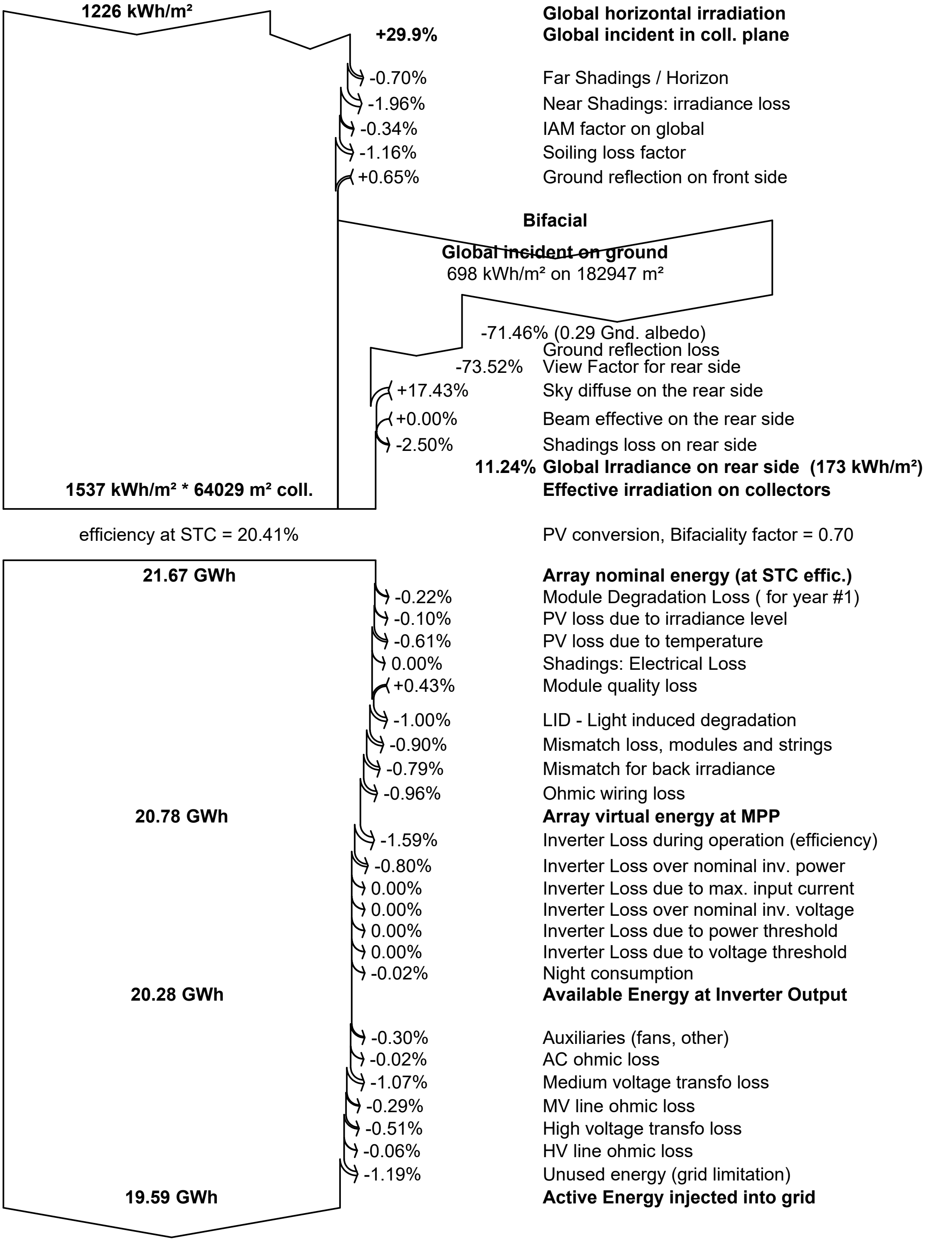
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray GWh	E_Grid GWh	PR ratio
January	32.0	17.71	-6.82	42.2	40.1	0.610	0.575	1.049
February	62.4	27.46	-6.83	84.8	81.4	1.245	1.195	1.084
March	102.7	43.95	-2.70	138.7	134.2	1.946	1.872	1.038
April	134.9	66.05	2.96	175.3	170.0	2.294	2.211	0.969
May	158.1	83.23	9.20	199.1	192.2	2.478	2.389	0.922
June	172.5	85.88	14.37	220.1	212.7	2.688	2.594	0.906
July	173.1	78.95	19.48	220.7	213.4	2.619	2.526	0.880
August	153.2	74.50	19.34	198.7	192.0	2.435	2.349	0.909
September	108.5	45.00	14.94	146.2	141.3	1.825	1.756	0.923
October	68.6	33.10	9.31	90.1	86.7	1.165	1.115	0.952
November	36.7	20.26	3.37	48.4	46.6	0.672	0.637	1.011
December	23.0	15.54	-2.53	28.3	26.4	0.403	0.374	1.015
Year	1225.8	591.63	6.25	1592.5	1537.0	20.380	19.593	0.946

Legends

GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_Grid	Energy injected into grid
T_Amb	Ambient Temperature	PR	Performance Ratio
GlobInc	Global incident in coll. plane		
GlobEff	Effective Global, corr. for IAM and shadings		

Loss diagram

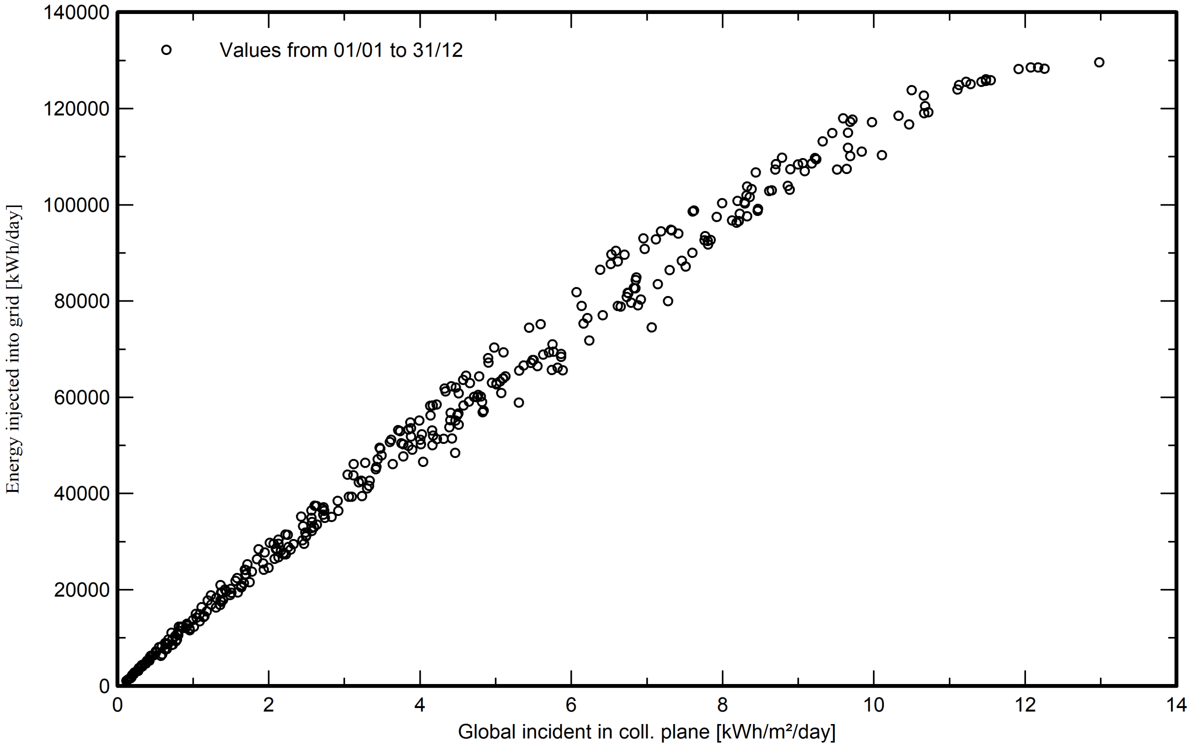


6.59 kVAR — Reactive energy to the grid: Aver. cos(phi) = 0.948

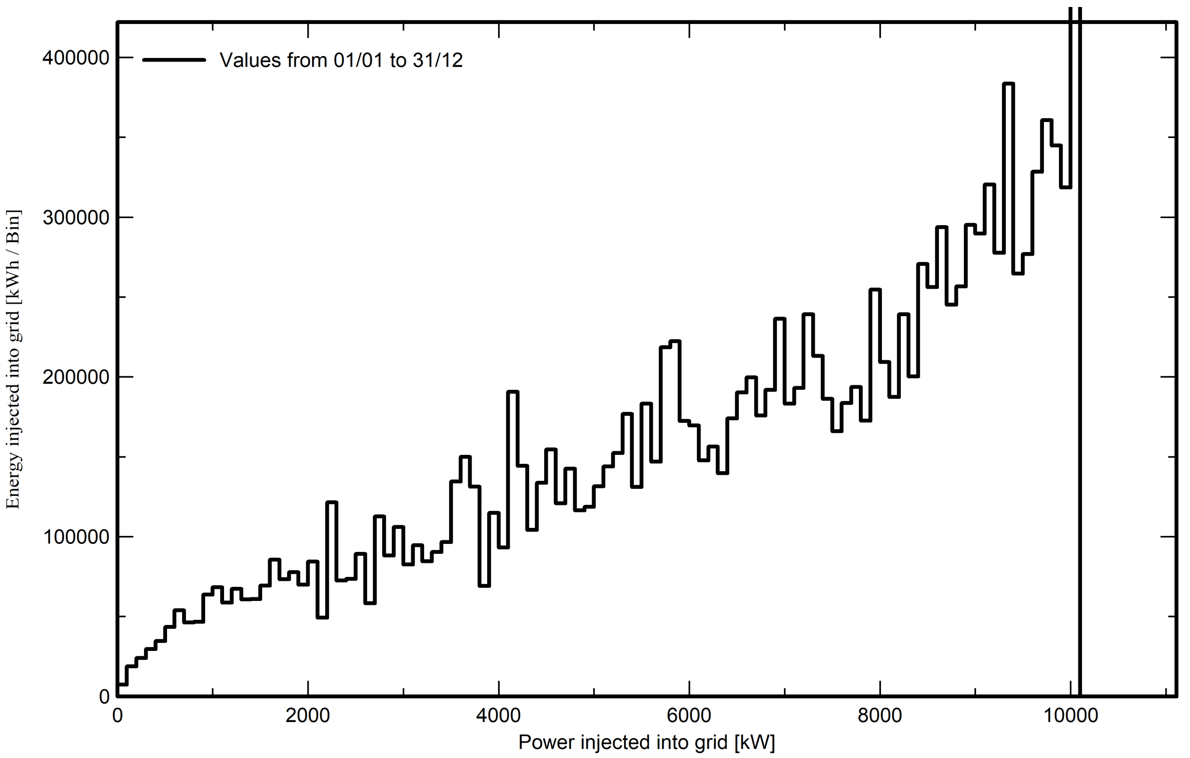
20.67 kVA — **Apparent energy to the grid**

Special graphs

Daily Input/Output diagram



System Output Power Distribution



MARITIME ELECTRIC
A FORTIS COMPANY
All our energy.
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INTERROGATORIES

IR-9 – Attachment 2

Extreme Weather Event Capacity Impact

Addendum to December 2022 Maritime Electric Capacity Resource Study

Prepared for

Maritime Electric Company, Ltd.

Prepared by Sargent & Lundy

Report SL-017775

Final

July 12, 2023

Project 14782.002

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ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this document has been prepared, reviewed, and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASSQC Q9001 Quality Management Systems.

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FIGURES AND TABLES

APPENDIXES

ACRONYMS AND ABBREVIATIONS

Acronym/Abbreviation	Definition/Clarification
BESS	Battery energy storage system
CAD	Canadian dollars
CT	Combustion turbine
EEA	Energy Emergency Alert
ISO	International Organization for Standardization
kW	Kilowatt
kWh	Kilowatt hour
LIL	Labrador Island Link
Maritime Electric	Maritime Electric Company, Limited
MECL	Maritime Electric Company, Limited
MW	Megawatt
MWh	Megawatt hour
NERC	North American Electric Reliability Corporation
PEI	Prince Edward Island
RICE	Reciprocating internal combustion engines
S&L	Sargent & Lundy
WEICAN	Wind Energy Institute of Canada

EXECUTIVE SUMMARY

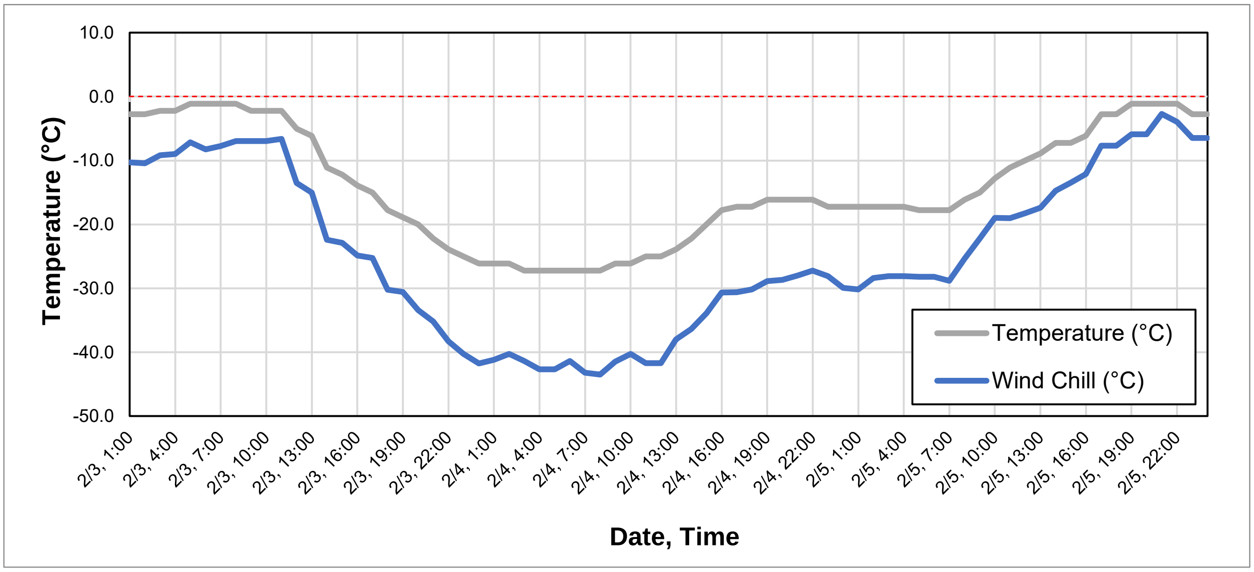
On December 9, 2022, Sargent & Lundy (S&L) issued a report titled *Capacity Resource Study: Evaluation of Various Technology Options for Maritime Electric Company*, which included an evaluation of different electricity capacity resource technologies, cost estimates, and recommend technologies well suited to helping Maritime Electric Company, Limited (MECL) meet its goals and needs. MECL's most important goals include meeting capacity and energy obligations, improving its ability to serve load during interruptions in electricity, and achieving environmental sustainability targets. The report ultimately concluded that a portfolio of reciprocating internal combustion engines (RICE) / combustion turbines (CTs), onshore wind, and solar photovoltaic was best suited to help MECL meet these goals. Based on a review of MECL's forecasted peak load at the time the previous report was written, S&L originally recommended that a minimum of 85 MW of new RICE/CTs with biofuel compatibility should be installed on Prince Edward Island (PEI) as soon as possible to reduce the probability of load shedding and rolling blackouts in the event of electricity import limits and/or interruptions from the mainland. In addition, while S&L's report did not recommend a new battery energy storage system (BESS) as part of the recommended portfolio, S&L noted that a new BESS could provide some benefits for MECL and PEI. As a result, S&L's report suggested that a new BESS demonstration project could be pursued, potentially in coordination with interested PEI stakeholders, to better assess the BESS functions/use cases that offer the maximum benefit for the island.

The purpose of this addendum is to revisit and revise some of the recommendations made in the prior report based on the observations made during a recent extreme cold event that transpired in the Maritimes region between February 3 through 5, 2023. The recent event highlighted both that (1) PEI is more susceptible to mainland electricity import interruptions or curtailments than originally assumed and (2) MECL's peak load is higher than previously forecasted during the preparation of the prior report.

EXTREME COLD WEATHER EVENT ON FEBRUARY 3 TO 5, 2023

During the period between February 3 and 5, 2023, large areas of Eastern Canada and the Maritimes provinces experienced extreme cold, driven by the disrupted southward movement of the northern polar vortex. This caused wind temperatures and wind chills to drop to below -40°C, as shown in Figure ES-1.

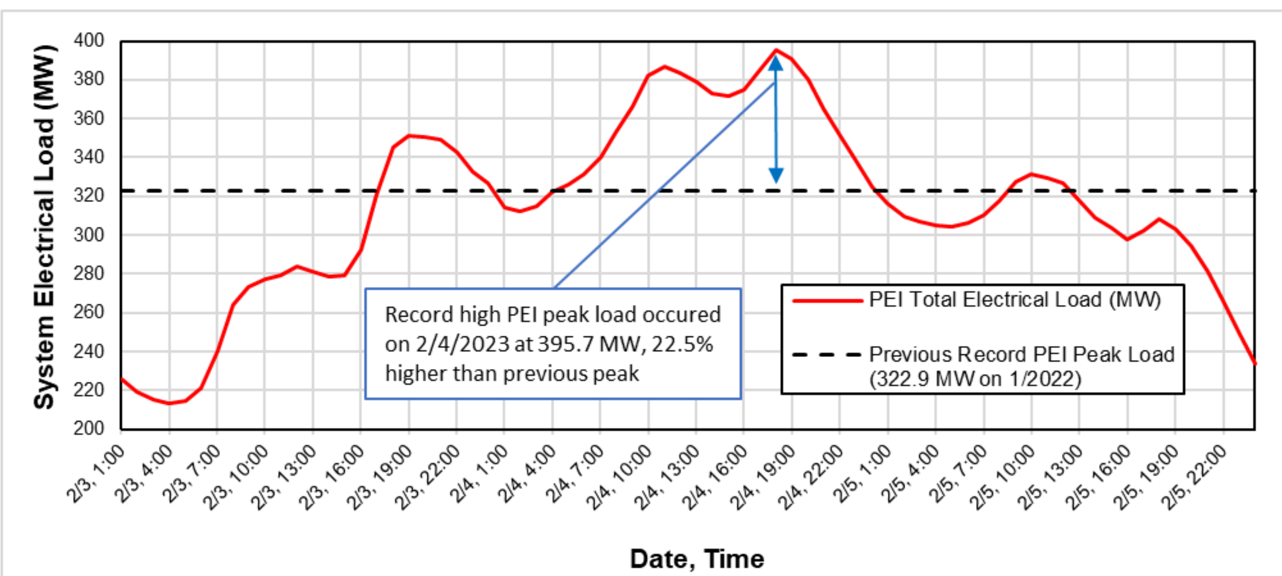
Figure ES-1 — Temperature and Wind Chill, Charlottetown (Feb. 3 to 5, 2023)



IMPACT TO PEI AND REGIONAL ELECTRICAL SYSTEMS

The extreme cold weather during February 3 to 5, 2023, caused record high demand for electricity on PEI and throughout Eastern Canada due to increased home heating load, commercial / industrial loads, and electrification. The high load resulted in significant stress on the electrical system, both locally and regionally. PEI experienced record electrical demand, with peak load for PEI soaring to 395.7 MW. This exceeded the previous load peak for PEI (set in 2022) by 22.5%.

Figure ES-2 — Electrical Load on PEI (Feb. 3 to 5, 2023)



This higher peak load experienced by PEI and in other parts of the Maritimes provinces, along with the stress the extreme weather had on other aspects of the electrical system (i.e., on generation and electrical equipment performance), resulted in a significant impact to grid operations and overall system reliability. The system's total hourly dispatch through the extreme cold event, in addition the wind generation through the event, are shown in Figure ES-3 and Figure ES-4. Given there is only enough dispatchable generation installed on PEI to meet a fraction (approximately 20%) of the peak electrical load experienced on PEI during the event, significant electricity imports from New Brunswick were required to meet PEI's electricity demand during the event. New Brunswick was able to provide imports with minimal curtailment; however, margins in New Brunswick were also very thin—to the point where New Brunswick had to declare an Energy Emergency Alert Level 2, which indicates that it was at serious risk of being unable to meet its firm load requirements (discussed further below). In addition, during the event the wind generation on PEI dropped significantly due to both the cold temperatures and high wind speeds resulting in equipment failures/shutdowns. PEI's relatively small amount of on-island dispatchable generation was dispatched without issue during the event.

Figure ES-3 — PEI Generation by Source (Feb. 3 to 5, 2023)

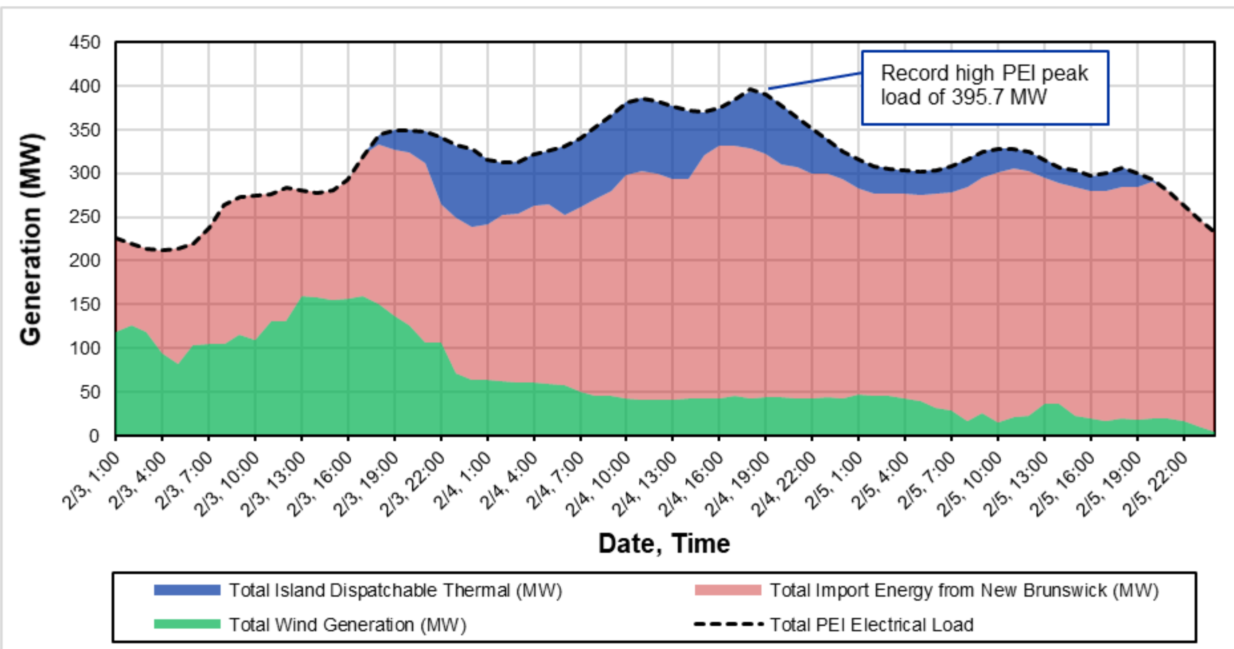
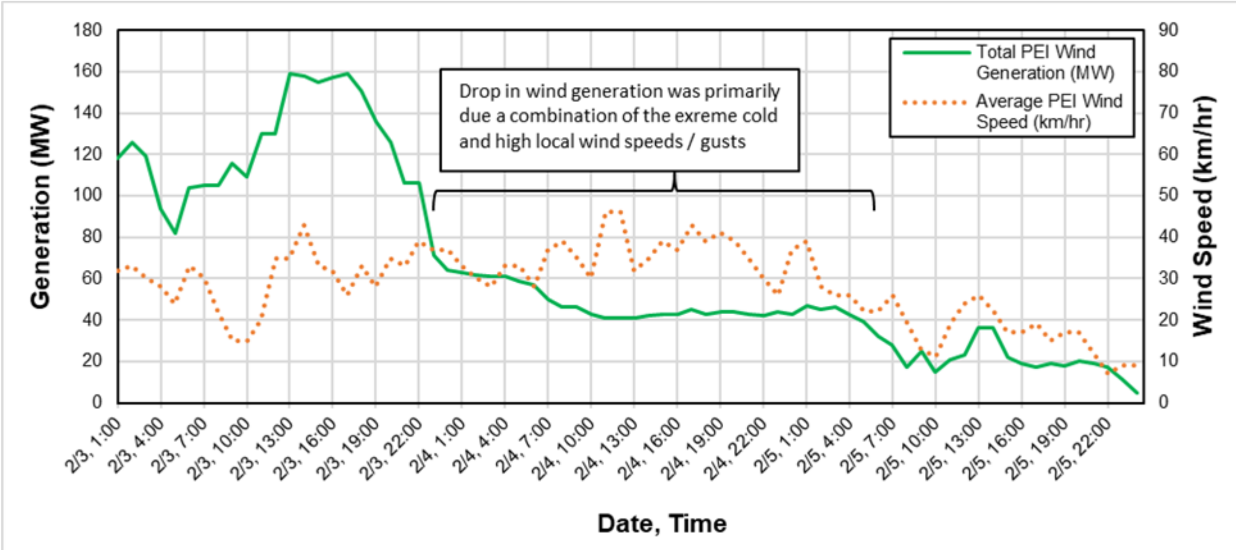
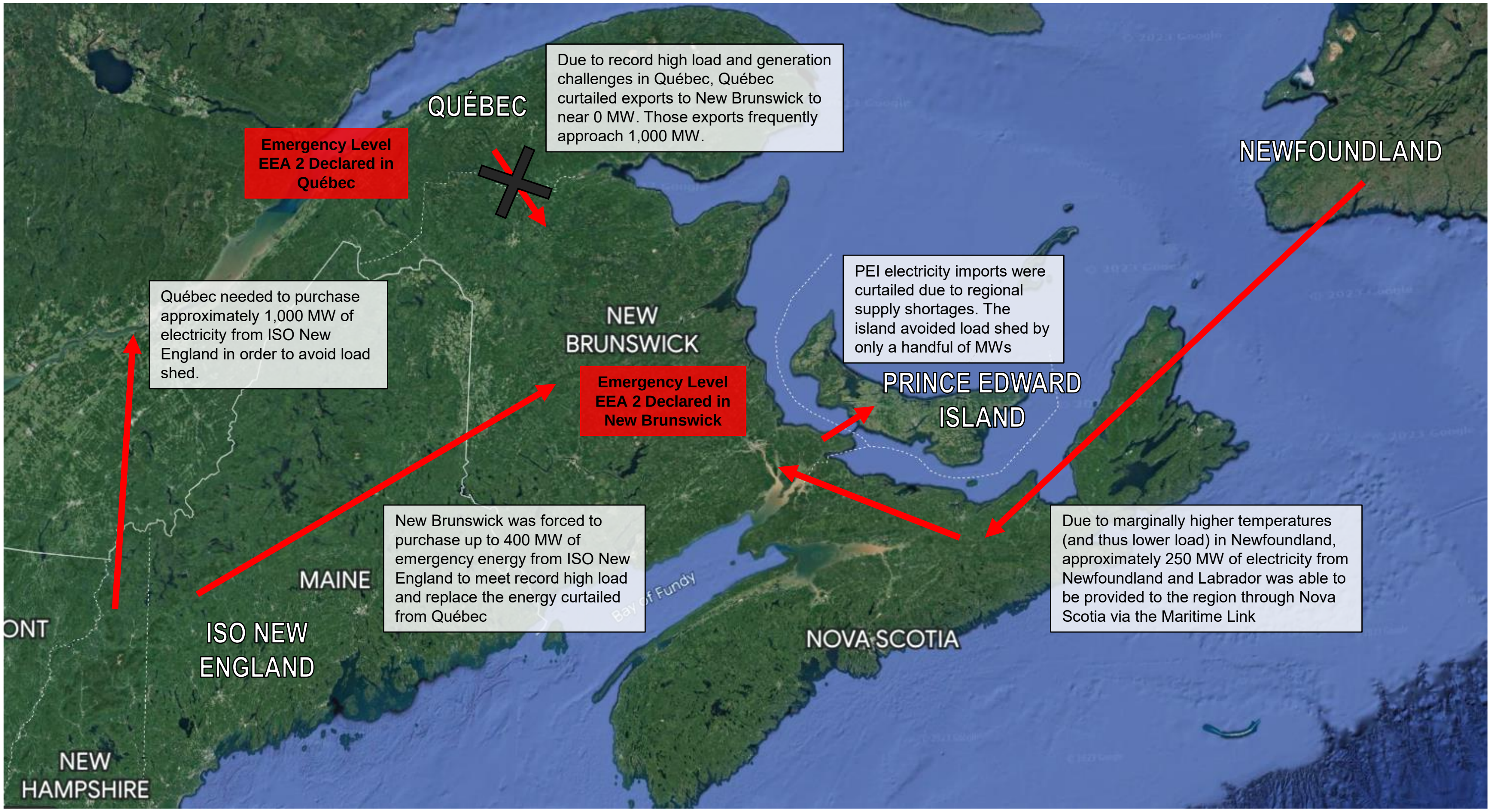


Figure ES-4 — PEI Wind Generation and Wind Speed (Feb. 3 to 5, 2023)



The extreme cold weather event severely strained the broader Maritimes regional electric system to the point where load shedding was a significant risk. Figure ES-5 summarizes the regional shortfalls, key electricity import/exports, and declared emergencies during the event. The provinces of Québec, Newfoundland and Labrador, Nova Scotia, and New Brunswick were all significantly impacted. Québec had to declare an Energy Emergency Alert Level 2 emergency and both (1) completely curtailed electricity exports to New Brunswick and (2) purchased emergency energy from New England, New York, and Ontario. As a result of the drop in electricity imports from Québec, in addition to record high peak electrical load, the New Brunswick electrical system was also pushed to emergency levels. Several factors, including electricity imports from ISO New England and Newfoundland and Labrador (through Nova Scotia), helped New Brunswick to avoid load shed. Had these imports not been available, it is likely that New Brunswick would have had to more significantly curtail electricity exports to PEI, which would likely have resulted in load shed on PEI during some of the coldest parts of the extreme cold event.

Figure ES-5 — Regional Recap, Evening February 3, Morning February 4, 2023



SIMILAR RECENT EVENTS AND INDUSTRY GUIDANCE

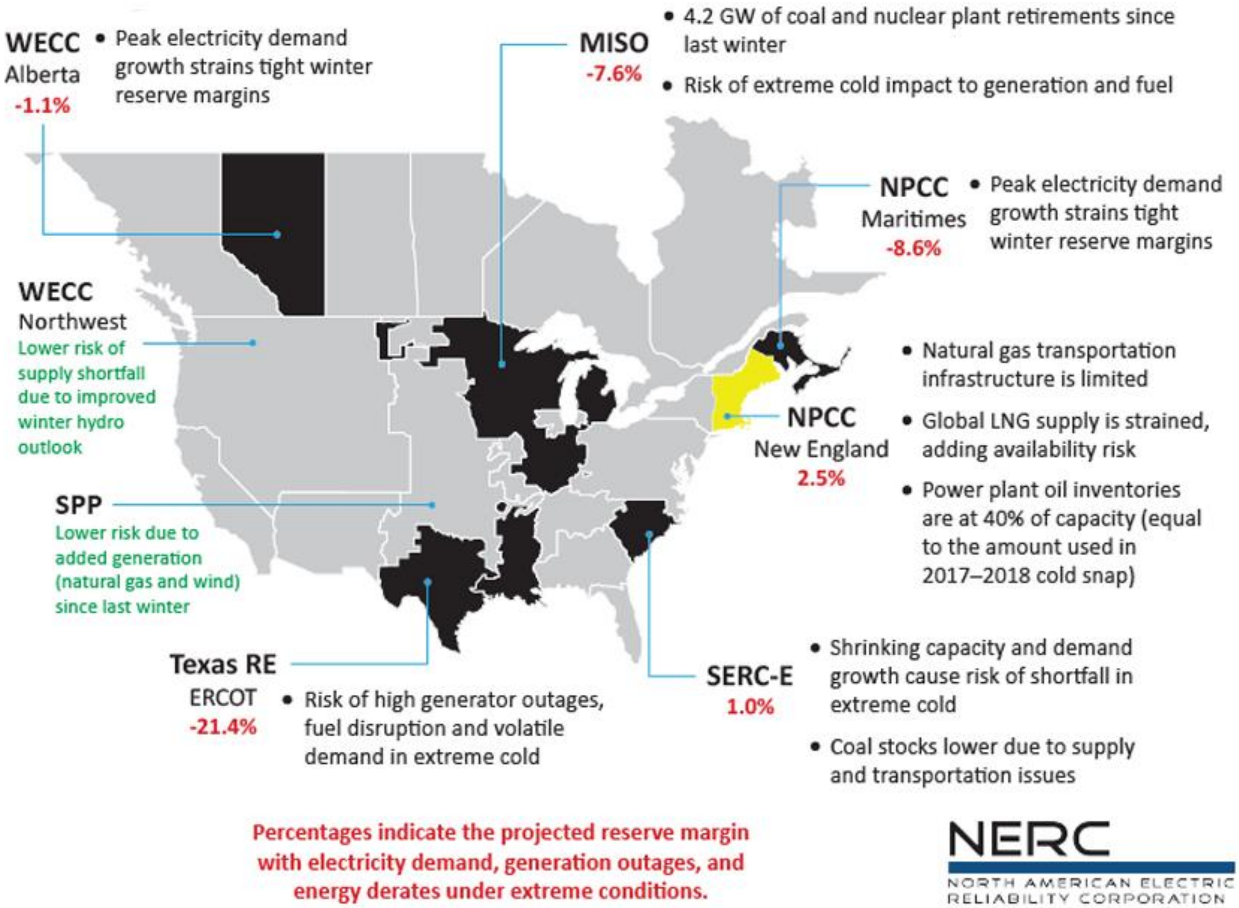
The extreme cold weather event that hit Eastern Canada on February 3 to 5, 2023, had many similarities to other recent events that also resulted in excessive strain on electric systems. The most notable recent event took place in 2021, when extreme cold from the North Pole pushed southward into the United States, all the way into Texas. In Texas, the cold also resulted in very high demand for electricity, disruptions to generators and the supply of natural gas, widespread power outages, and water shortages. The crisis led to billions in dollars of damage and the deaths of 246 people, two-thirds of which died from hypothermia.[2]

Given the stress recent extreme cold weather events have put on electrical systems, the North American Electric Reliability Corporation (NERC) has released a set of planning guidelines and recommendations regarding extreme cold weather events to come. For example, in November 2022, NERC released its *2022-2023 Winter Reliability Assessment,*[3] which highlighted that "some areas [of the bulk power system] are highly vulnerable to extreme and prolonged cold weather and may require load-shedding procedures to maintain reliability." The guideline notes that during extreme cold events, the Maritimes region is likely to have the second lowest electrical system reserve margins of all the electrical systems NERC oversees (see Figure ES-6 taken from the NERC guideline). Only Texas is estimated to have lower reserve margins. For PEI, this is an indication that electricity imports from the mainland to PEI are not guaranteed during future extreme cold events. Note that the reason for the estimated tight reserve margins in the Maritimes region is electrical load growth, which is driven by the rapid transition of buildings to electrical heating (and electrification in general) and commercial / industrial load.

In addition, on May 15, 2023, NERC released a Level 3 Essential Actions Alert titled *Cold Weather Preparations for Extreme Weather Events III.*[4] The alert was issued to "increase the Reliability Coordinators' (RC), Balancing Authorities' (BA), Transmission Operators' (TOP), and Generator Owners' (GO) readiness and enhance plans for, and progress toward, mitigating risk for the upcoming winter and beyond." For reference, a Level 3 Essential Actions Alert is the <u>highest</u> severity level that NERC issues and this is the <u>first time</u> a Level 3 Essential Actions Alert has ever been issued by NERC.

[2] https://www.texastribune.org/2022/01/02/texas-winter-storm-final-death-toll-246/
[3] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf
[4] https://www.nerc.com/news/Pages/NERC-Releases-Essential-Action-Alert-Focused-on-Cold-Weather-Preparations.aspx

Figure ES-6 — NERC Reliability Assessment for Extreme Cold Events[5]



UPDATED RECOMMENDATIONS FOR MECL

Due to the shortage in dependable resources seen during the February 2023 event, S&L has revised its previous recommendation to MECL of installing a minimum of 85 MW of new RICE/CTs with biofuel compatibility to a higher range of 125 to 150 MW of the same technology. This recommendation is based on the record peak load of 395.7 MW experienced on February 4, 2023. S&L continues to recommend the integration of both onshore wind and solar photovoltaic to help meet MECL's decarbonization goals but notes that these non-dispatchable resources may not be able to provide reliable generation during an emergency event (as was observed during the event between February 3 and 5, 2023). In addition, S&L continues to note that a new BESS demonstration project could help identify the BESS functions/use cases that offer the maximum benefit for the island. As is shown in Figure ES-7, an additional 125 to 150 MW of dispatchable capacity (RICE/CTs) would help to keep the ratio of dispatchable capacity to system peak

[5] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf

load, and thus risk of future load shed in the event of mainland electricity import shortages, near consistent with historical levels.

Figure ES-7 — Outlook of Dispatchable On-Island Capacity versus Peak Load

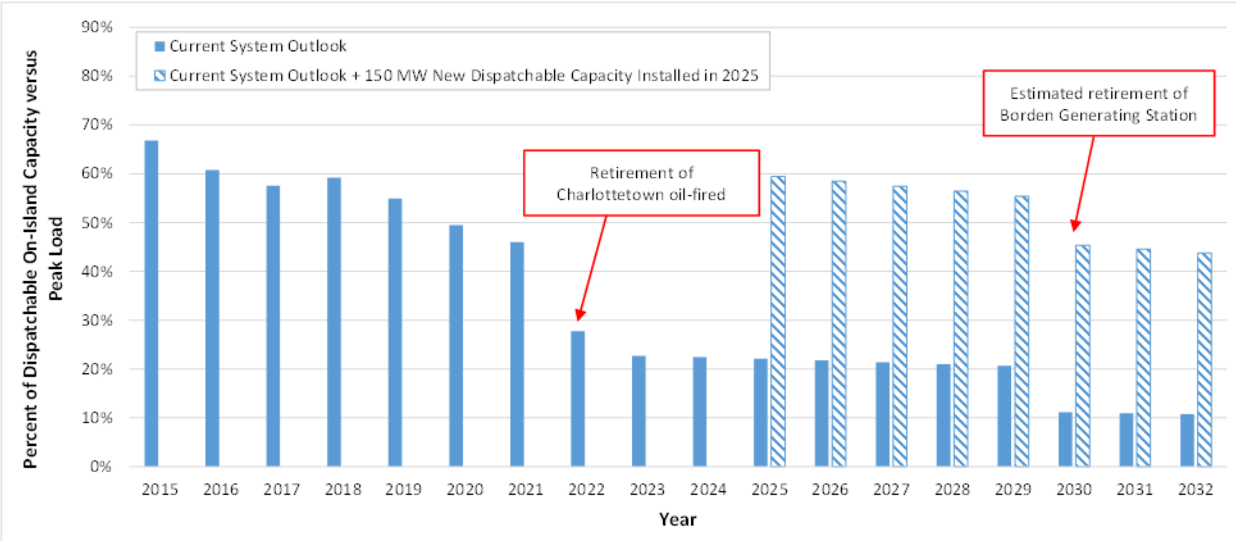


Table ES-1 summarizes the key operating details and levelized costs for CT and RICE options. A more detailed estimate of the CT design is included in Appendix A with the RICE details included in the previous report. Note the manufacturer and type of CT/RICE unit are chosen for comparison purposes only—many other manufacturers make similar units.

Table ES-1 — Estimated Costs for New CTs/RICE

Title	CT – Aeroderivative		RICE	
	GE LM6000 PF+ SPRINT		Wartsila 20V32	
Fuel Type	Diesel Only	Biodiesel Compatible	Diesel Only	Biodiesel Compatible
Winter Output (MW)	57.1 per turbine	57.1 per turbine	10.6 per engine	9.4 per engine
Net Heat Rate (Btu/kWh)	9,000	9,500	8,400	8,400
Levelized Install Cost (CAD/kW)	1,744	1,817	1,845	2,074
Synchronous Condenser Cost	Included	Included	Not included	Not included

There is also a need on PEI for additional electrical system support to maintain voltage levels and system stability, which is an ongoing challenge on PEI as additional wind generation is added to the electrical system. The 2020 MECL Integrated System Plan noted that after island load exceeds 350 MW, additional system voltage support (i.e., a synchronous condenser) will be needed on PEI[6]. Previous forecasts of island load estimated that levels higher than 350 MW would not be reached for a number of years; however, given PEI's load nearly reached 400 MW on February 4, 2023, additional system voltage support is needed today. For reference, both RICE and CTs can operate as synchronous condensers, which would help to improve the system's electrical performance; however, CTs are much more commonly used as synchronous condensers than RICE in the electricity industry. As a result, S&L recommends MECL pursue CTs over RICE if it is determined that a unit with synchronous condenser capability is required.

Finally, due to the unavailability of many of the wind generators on PEI during the February 3 to 5, 2023, event (as a result of equipment shutdowns caused by both the extreme cold and strong/turbulent winds), S&L recommends further information sharing and/or a technical conference, between MECL, the wind operators, and the wind generator original equipment manufacturers to fully understand what transpired and find solutions to prevent a repeat of the challenges experienced between February 3 and 5, 2023.

[6] Maritime Electric 2020 Integrated System Plan, page 44 and 47

1. INTRODUCTION AND EVENT DESCRIPTION

On December 9, 2022, Sargent & Lundy (S&L) issued the *Capacity Resource Study: Evaluation of Various Technology Options for Maritime Electric Company,* report number SL-017203. The report was developed for the purposes of evaluating a variety of different electricity capacity resource technologies, developing cost estimates, and recommending technologies well suited to help Maritime Electric Company, Limited ("MECL" or "Maritime Electric") cost-effectively achieve its most critical goals and needs, which are described as follows:

1. Meet both its capacity and energy obligations
2. Improve its ability to serve load during interruptions and/or curtailments in electricity imported from the mainland
3. Achieve sustainability targets

The report ultimately concluded that a portfolio of reciprocating internal combustion engines (RICE) / combustion turbines (CTs), onshore wind, and solar photovoltaic was best suited to help Maritime Electric meet these goals and needs. Based on a review of Maritime Electric's forecasted peak load at the time the report was written, S&L originally recommended that a minimum of 85 MW of new RICE/CTs with biofuel compatibility should be installed on Prince Edward Island (PEI) as soon as possible to reduce the probability of load shedding and rolling blackouts in the event of electricity import limits and/or interruptions from the mainland. Since the PEI system is winter peaking (i.e., the highest annual electricity demand occurs in the winter due to the demands of electric heating), in addition to the fact that winter in the Maritimes region can be particularly harsh, any load shed or rolling blackout events on PEI in the winter could have serious consequences both in terms of property damage and resident safety.

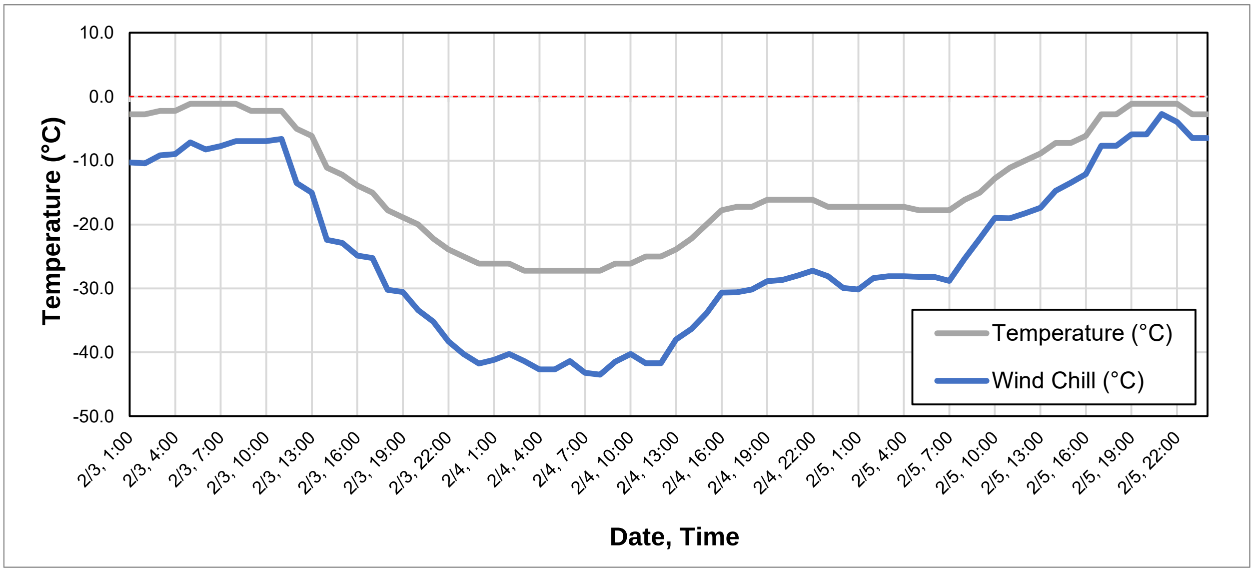
In addition, while S&L's report did not recommend a new battery energy storage system (BESS) as part of the recommended portfolio, S&L noted that a new BESS could provide some benefits for MECL and PEI. As a result, S&L's report suggested that a new BESS demonstration project could be pursued, potentially in coordination with interested PEI stakeholders, to better assess the BESS functions/use cases that offer the maximum benefit for the island.

The purpose of this addendum is to revisit and revise some of the recommendations made in the prior report based on the observations made during a recent extreme cold event that transpired in the Maritimes region between February 3 through 5, 2023. The recent event highlighted both that (1) PEI is more susceptible to mainland electricity import interruptions or curtailments than originally estimated when the prior report was written and (2) Maritime Electric's peak load is higher than what was previously forecasted. S&L is of the opinion that the events that transpired on February 3 to 5, 2023, should serve as an early warning example of the challenges PEI faces with respect to potential electricity disruptions during future extreme weather events.

1.1. EXTREME COLD WEATHER BETWEEN FEBRUARY 3 AND 5, 2023

During the period between February 3 and 5, 2023, large areas across Eastern Canada and the Maritimes provinces experienced extreme cold. Figure 1-1 illustrates the temperature and wind chill experienced in Charlottetown, PEI, between February 3 and 5, 2023. During the event, temperatures and wind chill values dipped significantly, with wind chill values falling to under -40°C. The high winds experienced across Eastern Canada and the Maritimes provinces drove the very low wind chill values, which also resulted in record electrical demand (as is shown in Figure 2-1) as residents heated their homes.

Figure 1-1 — Temperature and Wind Chill, Charlottetown (Feb. 3 to 5, 2023)[7,8]

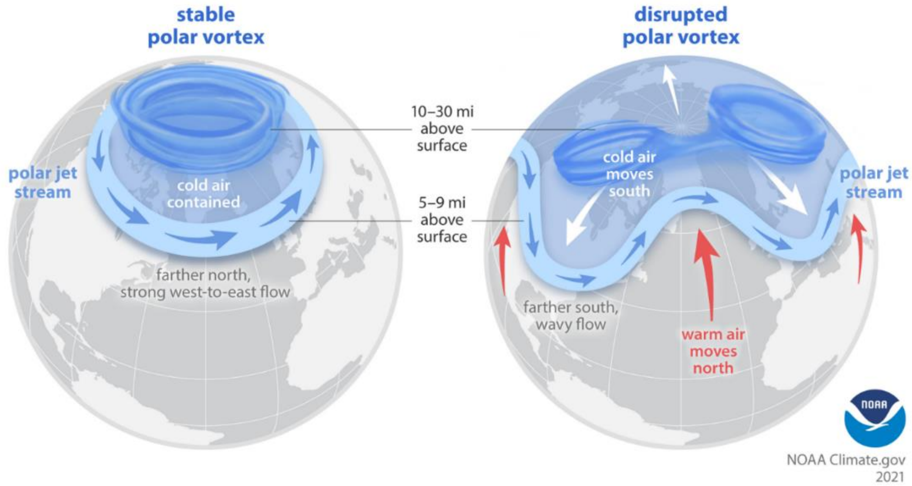


1.1.1. Extreme Cold and the Atmospheric Polar Vortex

The extreme cold in Eastern Canada that occurred between February 3 and 5, 2023, was the result of a disrupted polar vortex, which resulted in extremely cold air over the North Pole migrating southward. For reference, the polar vortex is a circulating mass of frigid air that is typically centered over the Earth's poles, held in place by strong jet stream air currents. In the event the jet stream air currents holding the frigid air over the Earth's poles weaken or fluctuate, the polar vortex can become disrupted and migrate towards the equator. Figure 1-2 helps to illustrate both stable and disrupted polar vortex atmospheric conditions.

[7] https://www.wunderground.com/history/daily/ca/charlottetown/CYYG/date/2023-2-3
[8] https://www.wpc.ncep.noaa.gov/html/windchill.shtml

Figure 1-2 — Polar Vortex Illustration[9]



As a result of the overall warming trend of the Earth, there is significant research ongoing by atmospheric and climate scientists as to whether more frequent and/or pronounced disruptions in the polar vortex will occur in the future, which could result in more extreme cold temperatures at southern latitudes during winter months. Some evidence suggests that frequent disruptions could be expected in the future. In S&L's opinion, regardless of whether global warming is found to increase the rate and/or severity of polar vortex disruptions in the future, extreme cold weather events already occur with sufficient regularity that proper planning and cold weather hardening of the electrical system is essential, especially when considering the growth of electric heating throughout the Maritimes region and Canada.

Listed below are notable recent extreme cold weather events for illustrative purposes. As can be seen, these events occur regularly.

- February 2023: The most recent extreme cold weather event and the subject of this report.
- December 2022: During the end of 2022, storms and a cold weather snap gripped much of North America, resulting in many record low temperatures across the continent and power outages across Canada and the United States.
- February 2021: This extreme cold event resulted in significant damage and loss of life across North America, with the state of Texas' electrical system suffering from widespread outages. This recent event, specifically what transpired in Texas, is discussed in detail in the following subsection.
- January 2019: This significant cold weather event struck Canada bringing both record snowfalls and cold weather to many provinces. Wind chills in parts of Ontario (both Toronto and Windsor), Manitoba, Saskatchewan, Alberta, and British Columbia approached -40°C during this event. Extreme cold temperatures also stretched into the United States, with the state of Michigan declaring

[9] https://www.climate.gov/news-features/understanding-climate/understanding-arctic-polar-vortex

a state of emergency due to the record cold temperatures and wind chills in the city of Chicago, Illinois, dropping to nearly -50°C.

- January 2014: Extreme cold weather and winter storms hit much of Eastern Canada and the United States, resulting in significant damage. High electrical demand as a result of the low temperatures, in addition to electrical equipment failures, resulted in the collapse of the electrical system in Newfoundland, where many residents were left without power for days. This event is described further in the following subsection.

1.2. ELECTRICAL SYSTEM FAILURES FROM EXTREME WEATHER

As is further described in Sections 2 and 3, the extreme cold weather event experienced in the Maritimes region between February 3 to 5, 2023, very nearly resulted in significant load shed across Eastern Canada, including on PEI. Two previous events where cold weather contributed to the failure of electrical systems are described below.

1.2.1. 2021 Texas Electrical System Failure

The 2021 Texas electrical system failure occurred as a result of a severe winter weather polar vortex event that pushed south into Texas for several days in February 2021, resulting in widespread power outages, water shortages, and other disruptions. The crisis was caused by a combination of factors, including extreme cold temperatures, high demand for electricity, insufficient electrical equipment winterization, and disruptions in the supply of natural gas.

Temperatures in the state dropped to a low of -19°C during the event,[10] which was the coldest temperature reached in over seven decades in some parts of the state, and the freezing temperatures lasted for up to eight days in some areas. The event had a significant impact on the state's electric grid, which is managed by the Electric Reliability Council of Texas. The extreme cold caused a surge in demand for electricity as people tried to keep their homes warm, while at the same time the extreme cold resulted in many power plants and natural gas facilities failing to operate. Much of the electrical and natural gas equipment in Texas was not winterized sufficiently, which resulted in frozen wind turbines, mechanical failures at natural gas plants, as well as fuel supply shortages, all of which crippled the generation capacity of the Electric Reliability Council of Texas.

The effects were far-reaching and profound. Approximately 4.5 million homes and businesses were left without power.[11,12] Many Texans were without power for days, and some were forced to resort to unsafe

[10] https://www.dallasnews.com/news/weather/2021/02/16/thousands-still-without-power-as-north-texas-reaches-record-low-temperature/
[11] https://www.nbcnews.com/news/weather/knocked-out-texas-millions-face-record-lows-without-power-new-n1257964
[12] https://time.com/5940232/millions-without-power-texas/

methods to stay warm—approximately 246 people lost their lives during the event, of which two-thirds died from hypothermia.[13] The freezing temperatures also caused water pipes to burst, leading to water shortages in some areas. Some residents had to boil water or rely on bottled water for drinking and cooking. It is estimated that the event caused nearly $200 billion in damage.[14]

While PEI did not experience load shed during the recent February 3 to 5, 2023, extreme cold event, PEI came extremely close to being unable to meet load; thus, it is instructive to consider the many parallels between Texas and PEI, highlighted below.

- The Texas's power grid (Electric Reliability Council of Texas) is designed to operate independently from the rest of the grid in the United States, effectively making the Electric Reliability Council of Texas an "island" that has very limited access to additional generating resources from other states in the United States during times of crisis. This resulted in Texas being unable to import emergency power from its neighbors during the 2021 polar vortex event. Because PEI is an island with both (1) a limited interconnection to the mainland (via New Brunswick) and (2) an insufficient amount of dispatchable on-island generating capacity to fully meet its own electrical load, PEI nearly was unable to fully meet electrical demand during the cold weather event between February 3 and 5, 2023. As is further described in Sections 2 and 3, PEI's mainland neighbors were nearly unable to meet their own load; thus, there was a significant risk that New Brunswick would have been forced to curtail electricity exports to PEI between February 3 and 5, 2023.
- The high demand for electricity in both Texas and recently on PEI (see Section 2) during the cold events was driven primarily by home heating, highlighting the need to plan for higher winter demand as in-home electric heating demand increases.
- Texas experienced the shutdown of many wind generators due to the freezing temperatures, stressing a need to further examine potential weatherization solutions to prevent turbines from freezing in future. As is discussed in Section 2, PEI also experienced a similar drop in wind turbine generation during the recent extreme cold event between February 3 and 5, 2023.

1.2.2. 2014 Newfoundland System Outages

During the period of January 2 to 8, 2014, Newfoundland experienced significant power outages following a winter storm and associated very cold weather. Investigations on the cause of the outages determined that they stemmed from two primary reasons:[15]

- An insufficiency of generating resources to meet customer demand
- A series of untimely system disruptions (electrical equipment failure, etc.)

[13] https://www.texastribune.org/2022/01/02/texas-winter-storm-final-death-toll-246/
[14] https://www.austintexas.gov/sites/default/files/files/HSEM/2021-Winter-Storm-Uri-AAR-Findings-Report.pdf
[15]http://www.pub.nf.ca/applications/IslandInterconnectedSystem/index.htm, Liberty Report - addressing Newfoundland and Labrador Hydro

During the event, the shortages in available generation required the province's utility to implement unprecedented rotating power outages. At the height of the event, nearly 200,000 customers in total were without power,[16] with some areas remaining in the dark for several days. The outages also affected critical infrastructure such as hospitals and water treatment facilities, leading to concerns about public health and safety. The storm also resulted in damage to power lines on the island, which further contributed to outages in Newfoundland. Thankfully, despite the severity of the storm and the cold temperatures, there were no deaths or serious injuries reported as a result of the power outages.

The assessment of the event showed that insufficient generation capacity, combined with both a peak load that surpassed the forecast and untimely system equipment failure, resulted in major system disruptions and blackouts. PEI is in a similar position to Newfoundland due to the fact that both islands have limited interconnections to neighbors. In addition, similar to Newfoundland, PEI is unable to fully meet its own electrical load with dispatchable on-island generation. As a result, it is not unlikely that the events that transpired between January 2 to 8, 2014, on Newfoundland could occur on PEI.

[16] https://www.theglobeandmail.com/news/national/newfoundland-closes-schools-as-power-outage-enters-fourth-day/article16203471/

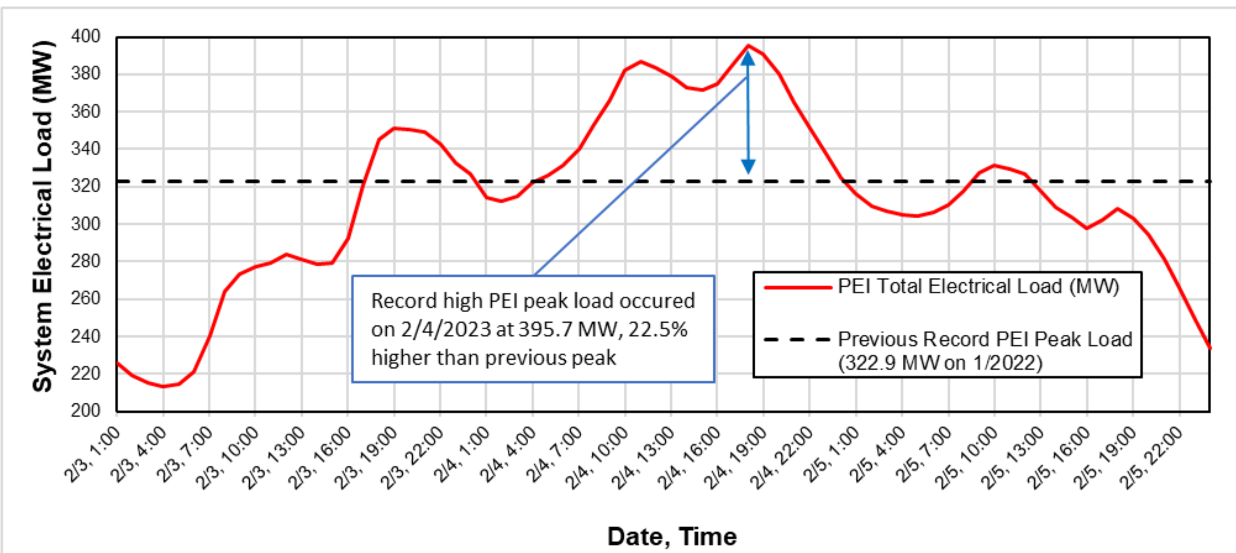
2. ELECTRICAL SYSTEM IMPACT – PEI

The extreme cold that hit Eastern Canada between February 3 and 5, 2023, resulted in a significant amount of stress on the electrical system both on PEI and throughout Eastern Canada in terms of high system load, generation disruptions, electricity import limitations, and load shed. This section focuses on the impacts to PEI, followed by a more general assessment of what transpired at the regional level in Section 3.

2.1. SYSTEM ELECTRICAL LOAD

The extreme cold weather experienced on PEI drove system electricity consumption levels to all-time records due to extremely high demand for electricity to heat homes and other buildings. Both PEI and MECL experienced record peak electrical load. Peak load for PEI soared to 395.7 MW (average between hours ending 17:00 and 18:00 on February 4, 2023, 399.2 MW instantaneously) and peak load for MECL hit a record high of 357 MW. Figure 2-1 illustrates the electrical load profile for PEI between February 3 and 5, 2023. As can be observed in Figure 2-1, the peak load experienced on February 4, 2023, was 22.5% higher than the previous peak set in January 2022.[17]

Figure 2-1 — Electrical Load on PEI (Feb. 3 to 5, 2023)



In the *Capacity Resource Study: Evaluation of Various Technology Options for Maritime Electric Company* issued by S&L on December 9, 2022, the electrical load that MECL serves was expected to increase in the coming years; however, peak load levels were not expected to rise to the levels experienced by MECL between February 3 and 5, 2023, for several years. As such, the recommendation for dispatchable capacity

[17] The previous peak load for PEI was 322.9 MW experienced between the hours of 17:00 and 18:00 on January 11, 2022.

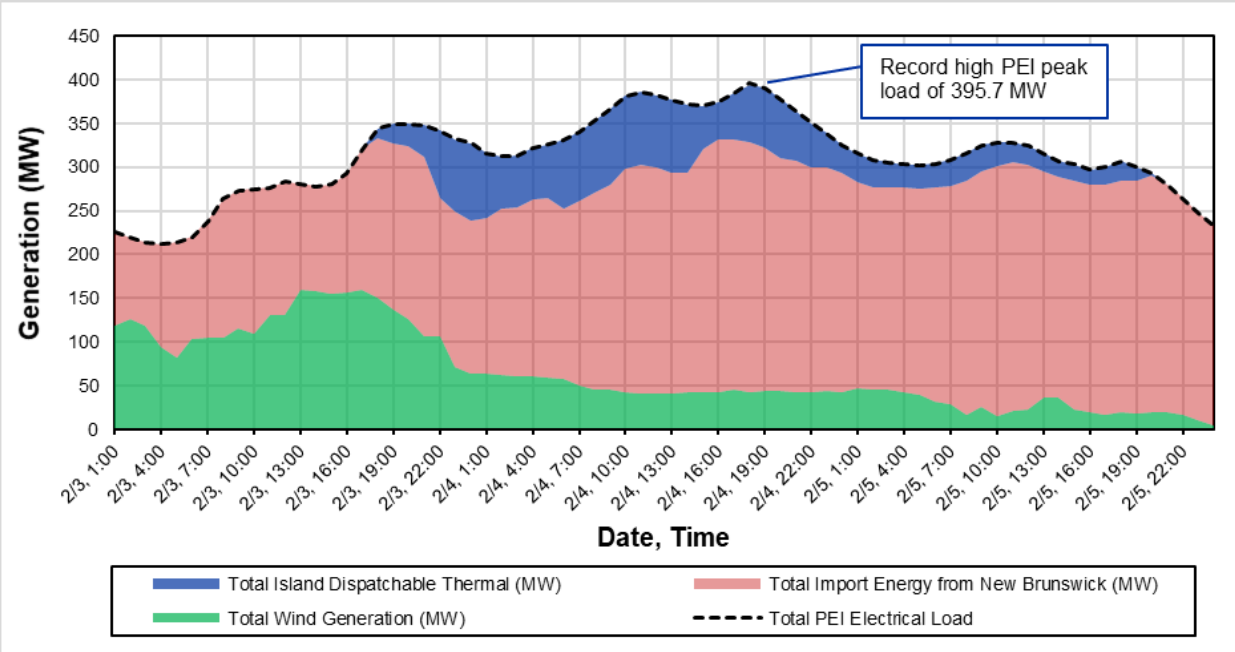
that MECL should install in the near future has been revised upward from the previous recommendation of 85 MW to a range of 125 to 150 MW, depending on the peak load forecast. A further discussion of this recommendation is provided in Section 5.1.

2.2. SYSTEM DISPATCH

Figure 2-2 illustrates total system dispatch by source during the period from February 3 through February 5, 2023. As is illustrated in Figure 2-2, electrical load on PEI was primarily met via imports from New Brunswick during the event. Wind generation was initially high on February 3, 2023; however, wind generation fell significantly throughout the event due to the extreme cold and high wind speeds experienced. Since the contract with New Brunswick is for a maximum of 300 MW, MECL chose to operate its dispatchable thermal generation installed on PEI to stay under this limit or risk curtailments from New Brunswick (New Brunswick did have to partially curtail imports to PEI by 50 MW on the evening of February 3, 2023). MECL's CTs also provided additional benefits such as voltage control and transformer offloading that enabled higher grid stability during this time. The peak imported power from New Brunswick was approximately 290 MW on February 4, 2023, at approximately 16:00.

As is discussed further in Section 3.3, due to the challenges of operating its own system through the extreme cold temperatures, there was a significantly high risk that New Brunswick was not going to be able to export any electricity to PEI. The fact that New Brunswick was able to provide PEI with between 200 and 300 MW of imports through the event (with minimal curtailments of 50 MW) was very fortunate and saved PEI from having to shed firm load. It is also worth noting that PEI's peak occurred during the evening of February 4, 2023, while some of the other provinces had peaks that occurred earlier in the day. Thus, it is a reasonable conclusion that if PEI had a coincident peak with the other provinces, New Brunswick may not have been able to provide PEI with this critical imported power.

Figure 2-2 — PEI Generation by Source (Feb. 3 to 5, 2023)



2.2.1. Generator Performance During Event

2.2.1.1. Wind Generation

As the extremely cold temperatures hit PEI between the evening of February 3, 2023, and the morning of February 4, 2023, there was a subsequent sharp drop in wind generation. Going into the evening of February 3, 2023, it was reported that approximately 80% of the individual wind turbines on PEI were operational. By February 5, 2023, only about 25% of the individual wind turbines on PEI were operational (i.e., 75% were in forced or planned outage). Figure 2-3 and Figure 2-4 illustrate the historical PEI wind generation along with wind speed and ambient temperature during the cold weather event.

Figure 2-3 — PEI Wind Generation and Wind Speed (Feb. 3 to 5, 2023)

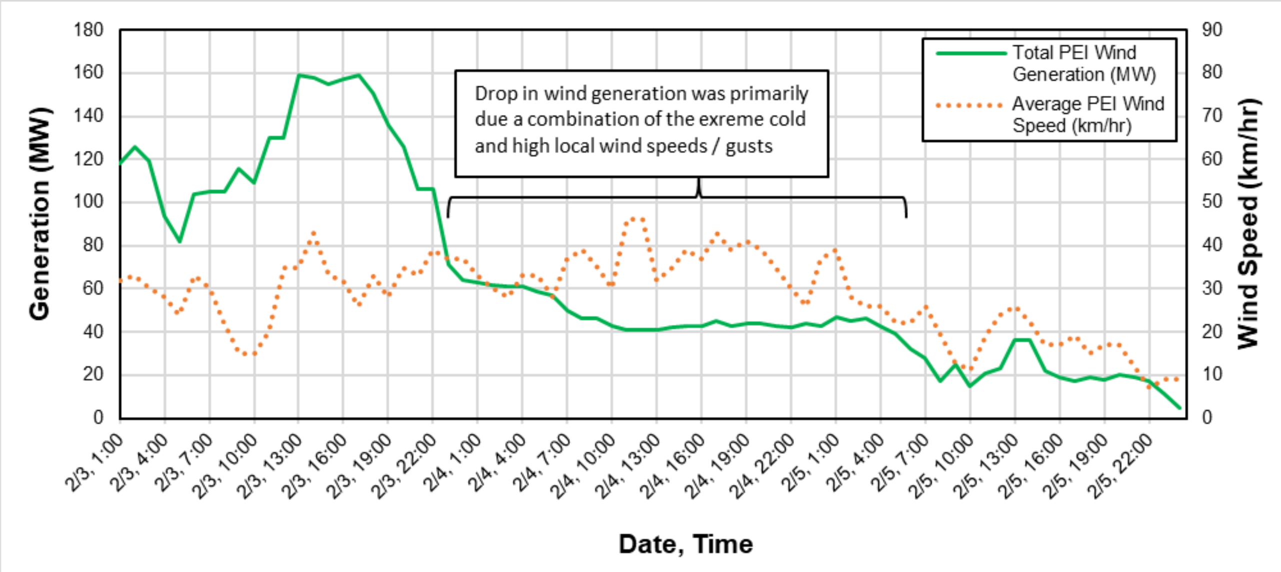
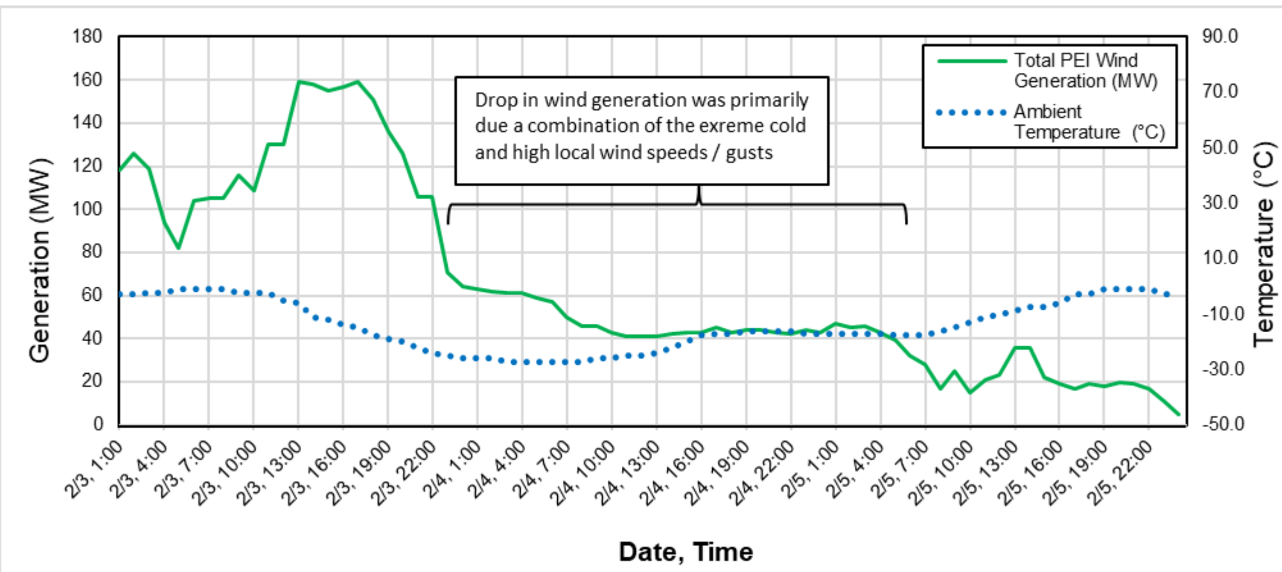


Figure 2-4 — PEI Wind Generation and Temperature (Feb. 3 to 5, 2023)



S&L had the opportunity to speak with the Wind Energy Institute of Canada (WEICAN) regarding the events that took place between February 3 and 5, 2023. WEICAN operates a number of wind turbine generators on PEI, some for research purposes. Per S&L's discussion with WEICAN, the drop in wind generation can be primarily tied to the following reasons:

- **Extreme Cold:** To avoid damage associated with extremely cold temperatures (which can cause equipment lubrication to harden, equipment material properties to change, etc.), wind turbine generators have safe shutdown setpoints that engage when temperatures drop below certain levels. A subset of the wind turbine generators that went offline on PEI experienced cold weather-related shutdowns. WEICAN explained that wind generators can be equipped with cold weather packages that allow the wind generators to operate at lower temperatures; however, the temperatures experienced on PEI were low enough to push the limits of even the wind generators equipped with cold weather packages.

- **Wind Speeds and Turbulence:** During the event, wind speeds (especially gusts) were very high, and the wind was turbulent. To avoid damage because of high wind speeds / high turbulence, wind turbine generators have safe shutdown setpoints that engage when wind speeds and/or turbulence rises above certain levels over a set period of time (i.e., over a 10-minute span). A subset of the wind generators that went offline on PEI experienced wind speed / turbulence-related shutdowns. If a wind generator goes into safe shutdown due to wind speed / turbulence, it is typically relatively easy to restart the generator again, once wind speeds / turbulence fall to levels low enough to safely operate the generator. However, this was not the case during the cold weather event in February because once the turbines went into shutdown, many quickly became too cold to easily restart. As a result, a subset of the turbines that went into shutdown due to high wind speeds / turbulence were unable to quickly restart and operate again because they were too cold.

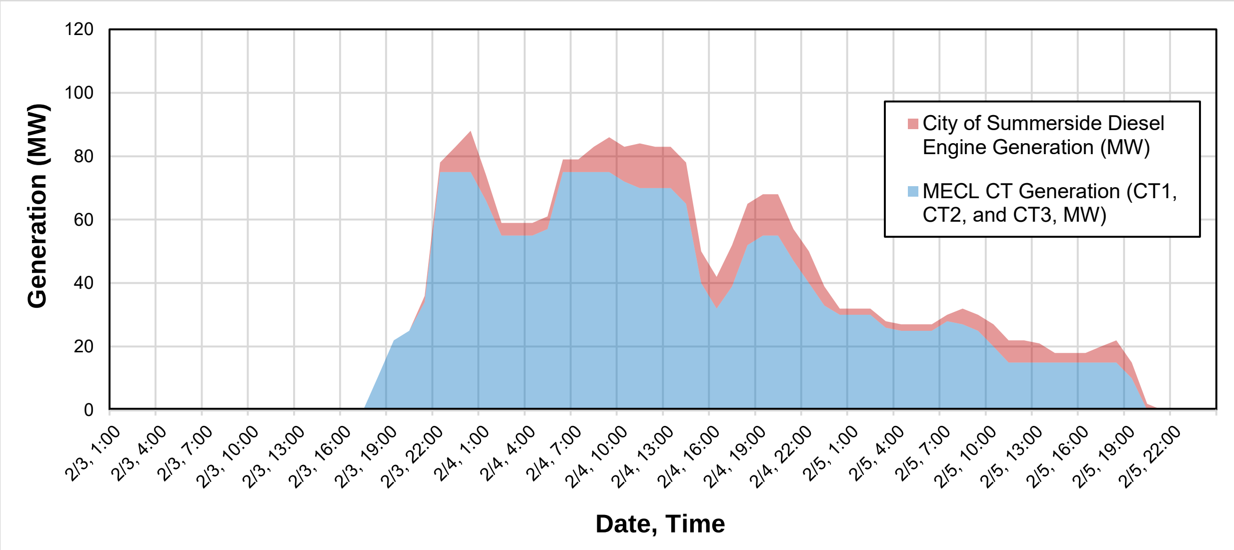
As a result of the large drop in wind generation, MECL was forced to rely even more on imported electricity from New Brunswick, in addition to operating its limited amount of dispatchable thermal generation installed on PEI, to serve load. As is discussed in Section 3.3, there was a significantly high risk that New Brunswick was going to be forced to curtail electricity exports to PEI during the event; thus, the drop in wind generation could have resulted in load shed across PEI.

2.2.1.2. Dispatchable Thermal Generation

The dispatchable thermal generation installed on PEI, which includes the Borden CT1 and CT2 units, the Charlottetown CT3 unit, and the Summerside engines (which are not owned by MECL), ran without incident throughout the event, with units started during the evening of February 3, 2023, and operating until February 5, 2023. The following figure provides the total generation of the thermal generation installed on PEI through the cold weather event.

As discussed above, the generation from the thermal resources was used to help meet record peak loads and offset the drop in wind generation experienced during the cold weather event, which helped PEI to stay below the 300 MW import limit from New Brunswick. During the event, the CTs also provided voltage control and transformer offloading, both of which helped to keep the grid stable.

Figure 2-5 — PEI Dispatchable Thermal Generation (Feb. 3 to 5, 2023)



3. ELECTRICAL SYSTEM IMPACT – REGIONAL

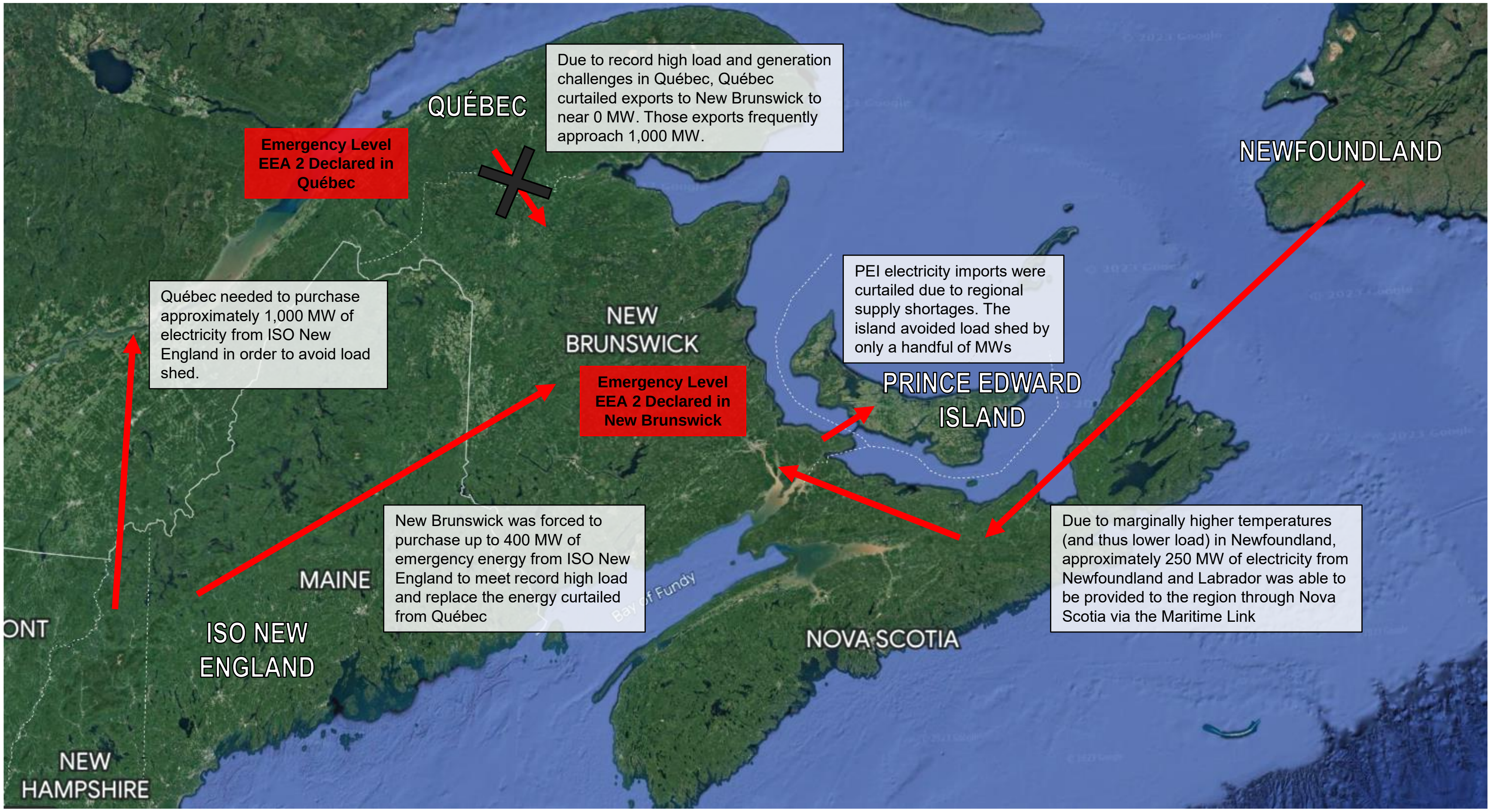
The extreme cold weather experienced in Eastern Canada on February 3 through February 5, 2023, severely strained regional electrical systems to the point that load shedding was a significant risk. To illustrate the severity of what occurred, it is first important to understand the levels at which system emergencies are classified within electrical systems. Below are the different Energy Emergency Alert (EEA) levels, with EEA 3 being the most severe. During the event, both Québec and New Brunswick declared emergencies at an EEA 2 level. The following classifications are provided by the North American Electric Reliability Corporation (NERC)[18].

- **EEA 1:** This is the first emergency level and is defined as “the balancing authority is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required contingency reserves.” As part of EEA 1, non-firm wholesale energy sales have been curtailed.
- **EEA 2:** EEA 2 is defined as a situation where “the balancing authority is no longer able to provide its expected energy requirements and is an energy deficient balancing authority.” Under an EEA 2 situation, the balancing authority still is able to maintain minimum contingency reserve requirements. A balancing authority experiencing an EEA 2 emergency is at serious risk of having to shed firm load and will take all potential steps possible to avoid firm load shed.
- **EEA 3:** Under an EEA 3 situation, the balancing authority is either currently shedding firm load or firm load shed is imminent. EEA 3 is the most serious of the EEA levels as it means there are or will be power outages / rolling blackouts.

Figure 3-1 provides an overview of the Maritimes region electrical system through the evening of February 3, 2023, and into the morning of February 4, 2023, which was the point at which the risk of load shed became the highest. Additionally, a brief overview of the challenges experienced within each area of the region is provided in the following subsections.

[18] https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf

Figure 3-1 — Regional Recap, Evening of February 3 and Early February 4, 2023



3.1. QUÉBEC

The extreme cold drove electrical demand in Québec to record levels. That, in combination with generator operational challenges driven by the cold, resulted in Québec becoming energy deficient and needing to declare an EEA 2 level emergency. To serve its own system and avoid significant load shed, Québec curtailed exports to New Brunswick down to 0 MW. For reference, the export capacity from Québec to New Brunswick is approximately 1,000 MW, and real-time exports rising to this level is not uncommon. In addition, Québec purchased nearly 1,000 MW of emergency energy from ISO New England, in addition to electricity from New York and Ontario. For perspective, Québec is usually a net exporter of electricity to ISO New England and had not purchased energy from New England since 2016.[19] Since Québec is a very large and relied-upon producer of electricity in the region, the challenges experienced in Québec reverberated throughout the region.

During this time, Québec did not have excess generation capacity to spare and was thus unable to export any electricity to New Brunswick, even though the existing intertie is approximately 1,000 MW.

3.2. NEWFOUNDLAND AND LABRADOR

Newfoundland and Labrador is intertied to Nova Scotia via a sub-sea electrical cable system known as the Maritime Link. This linkage allows for the export of up to 500 MW of electricity from Newfoundland and Labrador to Nova Scotia. Between February 3 and 5, 2023, Newfoundland and Labrador was able to export over 200 MW of electricity to Nova Scotia, which helped to alleviate the electricity shortfalls throughout the region. One of the key reasons that Newfoundland and Labrador was able to export this electricity was because temperatures in Newfoundland and Labrador did not fall to the record lows experienced to the immediate south; thus, electrical demand in Newfoundland and Labrador was relatively lower than the record electrical demand levels experienced in Québec, Nova Scotia, New Brunswick, and PEI.

Throughout the event, a key concern related to Newfoundland and Labrador's ability to export electricity to Nova Scotia was the availability of the Labrador Island Link (LIL), a transmission line that connects Labrador, where the 824-MW Muskrat Falls hydroelectric generating station is located, to the island of Newfoundland. Availability of the LIL is essential to allow electricity generated in Labrador to flow to Newfoundland, where it can then be exported south into Nova Scotia. The island of Newfoundland alone does not have enough excess generation capacity installed to support significant export to Nova Scotia; if

[19]https://isonewswire.com/2023/04/06/winter-2022-2023-recap-wholesale-prices-drop-during-warm-season-marked-by-cold-snaps/

the LIL is out of service, generation from Labrador cannot flow into Newfoundland to be exported to Nova Scotia.

Historically, Newfoundland and Labrador Hydro, the operator of the Muskrat Falls generating station and the LIL, had estimated the forced outage rate of the LIL to be 0.0114%.[20] However, in late 2022, Newfoundland and Labrador Hydro issued a report titled *Reliability and Resource Adequacy Study Review; Reliability and Resource Adequacy Study – 2022 Update*, in which the previously estimated forced outage rate of the LIL was revised from 0.0114% to a range of between 1% and 10% (to be more precisely quantified at a later date), which equates to a reliability level that is approximately 100 times to 1,000 times less than previously estimated. Fortunately, the LIL was in service between February 3 and February 5, 2023. Had it been out of service during this time, the result would have been an increased likelihood of load shed on PEI during the coldest part of the event.

3.3. NEW BRUNSWICK

New Brunswick saw record electrical load levels between February 3 and 5, 2023, similar to the other Eastern Canada areas. New Brunswick Power indicated to MECL that their peak load hit a high of 3,395 MW on the morning of February 4, 2023, 62 MW higher than their previous peak electrical demand level of 3,333 set in January 2004. It is worth noting that high winds caused approximately 4,000 customers in New Brunswick to lose power on February 4, 2023, which resulted in peak electrical demand being about 20 MW lower than it would have been had those customers not been disconnected. In addition, New Brunswick Power had cut 130 MW of interruptible load. Combined with high load, New Brunswick also experienced similar drop-offs in wind generation to what was experienced on PEI, and some of New Brunswick's generators experienced operational challenges because of the extreme cold weather.

The most significant event that led to New Brunswick having to declare an emergency of level EEA 2 was Québec's need to stop the export of electricity to New Brunswick. The capacity of the interconnection between Québec and New Brunswick is significant at approximately 1,000 MW; thus, the lack of any imports from Québec pushed New Brunswick to the brink of having to further curtail electricity exports to PEI and to also shed load within New Brunswick. Fortunately, New Brunswick only had to curtail exports to PEI by 50 MW. Three of the most significant events that allowed New Brunswick to avoid more significant, or complete, curtailment of exports to PEI were the following:

[20] Link to the recently released *Reliability and Resource Adequacy Study Review*
Reliability and Resource Adequacy Study – 2022, released by Newfoundland and Labrador Hydro in October 2022: UpdateRehttp://www.pub.nf.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%20Reliability%20and%20Resource%20Adequacy%20Study%20-%202022%20Update%20-2022-10-03.PDF

1. **Electricity Imported from ISO New England**: This electricity proved to be essential, and it allowed New Brunswick to continue to export electricity to PEI. It was fortunate that ISO New England was able to provide electricity to New Brunswick because New England also faces challenges (primarily related to fuel supply) in the face of extreme cold weather events. These challenges are highlighted in recent NERC guidance and further described in Section 4 of this report.
2. **Electricity Imported from Nova Scotia and Newfoundland and Labrador:** The electricity that Nova Scotia was able to provide to New Brunswick also helped New Brunswick continue to export electricity to PEI. Part of the reason that Nova Scotia was able to export electricity to New Brunswick was because Nova Scotia was able to import electricity from Newfoundland and Labrador via the Maritime Link, as discussed previously.
3. **Operation of the Thermal Resources on PEI:** The operation of the thermal generation located on PEI (all three MECL CTs and the Summerside engines) helped to generate approximately 80 MW of electricity from late February 3 through February 4, 2023, which were the most critical times during the extreme cold event. The thermal generation on PEI helped to partially offset the failure of the wind generation located on PEI that was experienced during the event. Without the generation from the thermal generators on PEI, the need for imported power would have been greater, increasing the risk from import curtailments.

3.4. ISO NEW ENGLAND

During the extreme cold event, ISO New England was able to serve as an essential import provider to both Québec and New Brunswick as both purchased significant amounts of electricity from ISO New England. Approximately 1,000 MW of electricity exports were sent to Québec and a peak of 400 MW of exports were sent to New Brunswick during the most critical times of the event. Real-time electricity prices soared to $500/MWh on February 4, 2023, (typically prices are in the $20 to $40/MWh range) which is an indication that total electrical demand approached the available supply within ISO New England. ISO New England notes that demand would likely have been higher if February 3 through 5, 2023, had not been weekend days.[21]

3.5. NOVA SCOTIA

Information regarding the electrical system challenges faced by Nova Scotia during the extreme cold weather event that transpired between February 3 and 5, 2023, mirrored much of which was experienced in the rest of the region. Nova Scotia's peak load experienced on February 4, 2023, was 10% higher than the previous peak experienced in 2004. As previously discussed, Nova Scotia was able to import electricity from Newfoundland and Labrador throughout the event, which helped to not only allow Nova Scotia to meet

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21 https://isonewswire.com/2023/04/06/winter-2022-2023-recap-wholesale-prices-drop-during-warm-season-marked-by-cold-snaps/

system load, but also export some excess electricity to New Brunswick (which ultimately helped to avoid New Brunswick from further having to curtail PEI).

3.6. PRINCE EDWARD ISLAND

Fortunately, PEI was able to get through the events of February 3 through 5, 2023, without having to implement load shed due to electricity shortages. However, in many respects, PEI was in the most precarious position of any location within the entire region. This is because PEI does not have enough dependable capacity installed on the island to fully meet peak load and thus required continuous imported electricity from New Brunswick in order to avoid load shed. While the wind generation installed on PEI is an excellent resource from the perspective of lowering carbon emissions for the island, wind generation is not a dispatchable resource in an emergency. This was evident during the extreme cold event that took place as only 25% of the wind turbines were operational (i.e., 75% were in forced or planned outage) during the most critical, coldest time of the event. PEI was fortunate that ISO New England, Newfoundland and Labrador, and Nova Scotia had some small amount of excess electricity to send to New Brunswick during the event—without electricity from these locations, New Brunswick would have been forced to further or completely curtail electricity exports to PEI, which would have resulted in significant load shed on PEI.

In the *Capacity Resource Study: Evaluation of Various Technology Options for Maritime Electric Company*, issued by S&L on December 9, 2022, an important focus was related to a scenario where PEI is electrically disconnected from the mainland. Many of the recommendations in the study were rooted in that specific scenario, which has occurred infrequently in the past. The extreme cold weather event that transpired between February 3 and 5, 2023, illustrates a similar, but fundamentally different scenario—one where the interconnection between PEI and the mainland remains operational, but electricity shortages on the mainland result in the curtailment of electricity imports to PEI. In terms of impact to PEI, this scenario is essentially equivalent to a scenario where the interconnection to the mainland becomes inoperable—both scenarios are likely to result in electricity shortages on PEI and thus load shed.

One important point to note is that when a utility experiences a shortage of electrical generation, its first priority is to serve its own load, which may require the utility to cut exports (for example, Québec cut exports to New Brunswick during the February cold weather event so that it could meet its own electrical load). In the event that PEI's thermal generators and wind and solar power plants are unable to generate a sufficient amount of electricity to support PEI's load, which they did not during the February 2023 event, PEI is dependent on imported electricity from the mainland to serve load. As was demonstrated during the February 2023 event, MECL and the other utilities in the region will attempt to generate and secure enough electricity to fully serve regional load during an emergency event; however, if there is not enough generation in the region to fully serve load, the other regional utilities will first prioritize their own load over exporting electricity to PEI. In this situation, the risk for load shed on PEI is high, which would put the residents of PEI in danger.

4. NERC WINTER RELIABILITY ASSESSMENTS

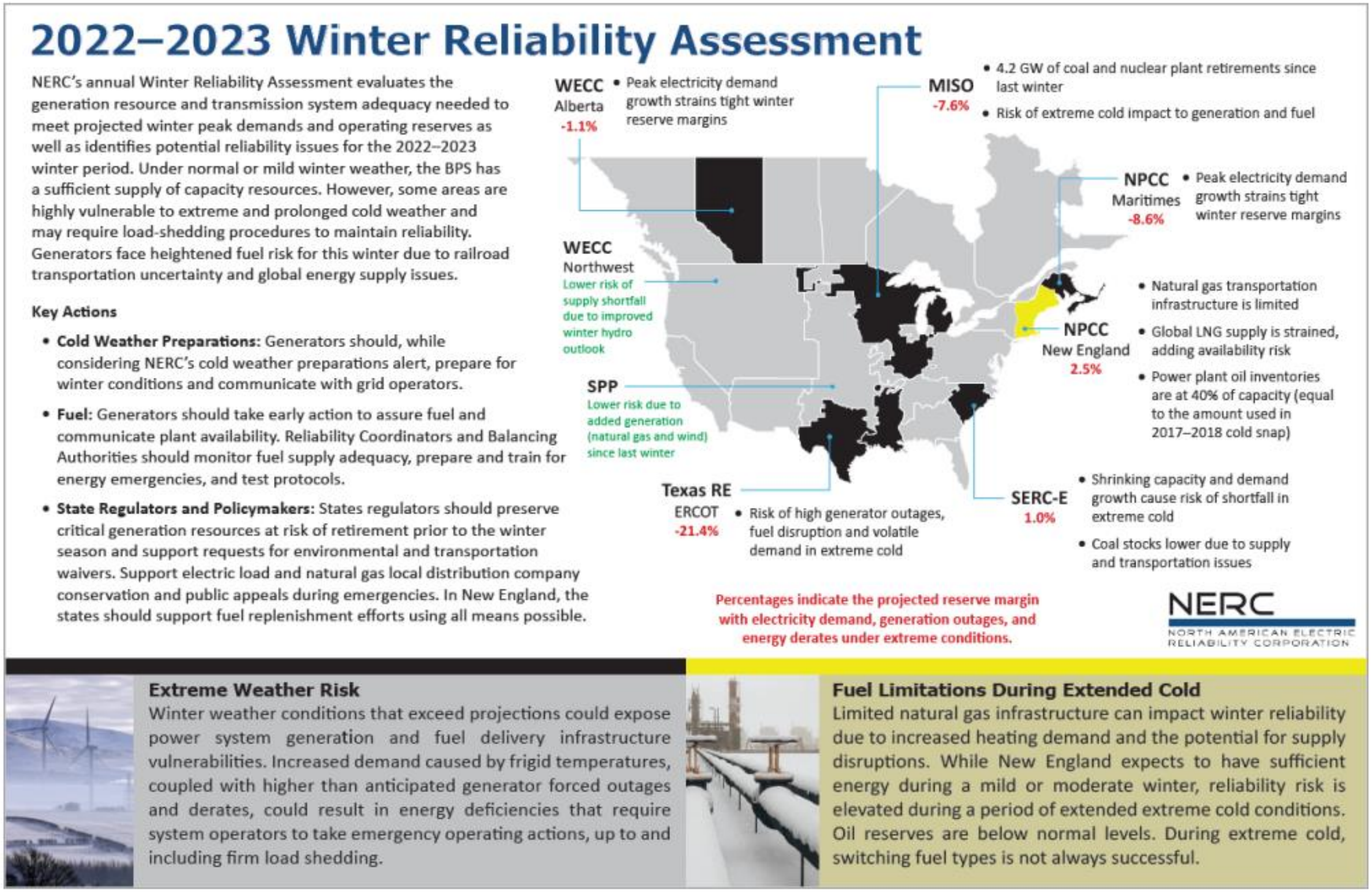
Given the stress recent extreme cold weather events have put on electrical systems, NERC has released a set of planning guidelines and recommendations regarding extreme cold weather events to come. For example, in November 2022, NERC released its *2022-2023 Winter Reliability Assessment,*[22] which highlighted that "some areas [of the bulk power system] are highly vulnerable to extreme and prolonged cold weather and may require load-shedding procedures to maintain reliability." The report is meant to inform industry leaders, planners, operators, and regulatory bodies to take necessary actions to ensure reliability. The guideline notes that during extreme cold events, the Maritimes region is likely to have the second lowest electrical system reserve margins of all the electrical systems NERC oversees (see Figure 4-1 taken from the NERC guideline). Only Texas is estimated to have lower reserve margins. The reason for the estimated tight reserve margins in the Maritimes region is electrical load growth, which is driven by the rapid transition of buildings to electrical heating (and electrification in general) and commercial / industrial load. In addition, NERC also notes that New England faces challenges during extreme cold events, primarily due to fuel supply constraints.

In addition, on May 15, 2023, NERC released a Level 3 Essential Actions Alert titled *Cold Weather Preparations for Extreme Weather Events III.*[23] The alert was issued to "increase the Reliability Coordinators' (RC), Balancing Authorities' (BA), Transmission Operators' (TOP), and Generator Owners' (GO) readiness and enhance plans for, and progress toward, mitigating risk for the upcoming winter and beyond." For reference, a Level 3 Essential Actions Alert is the highest severity level that NERC issues and this is the first time a Level 3 Essential Actions Alert has ever been issued by NERC.

The assessments and recommendations from NERC illustrate that many parts of North America are at risk during extreme cold weather events. Among the locations facing the greatest challenge is the Maritimes region. For PEI, this is an indication that electricity imports from the mainland to PEI are not guaranteed during future extreme cold events.

[22] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf
[23]https://www.nerc.com/news/Pages/NERC-Releases-Essential-Action-Alert-Focused-on-Cold-Weather-Preparations.aspx

Figure 4-1 — NERC 2022–2023 Winter Reliability Assessment[24]



[24] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf

5. RECOMMENDATIONS

The following sections highlight updated recommendations to the *Capacity Resource Study: Evaluation of Various Technology Options for Maritime Electric Company* issued by S&L on December 9, 2022. All recommendation updates are based on lessons learned from the extreme cold weather event that took place between February 3 and 5, 2023. Note that the recommendations in this section supersede those in the previous report, unless explicitly noted.

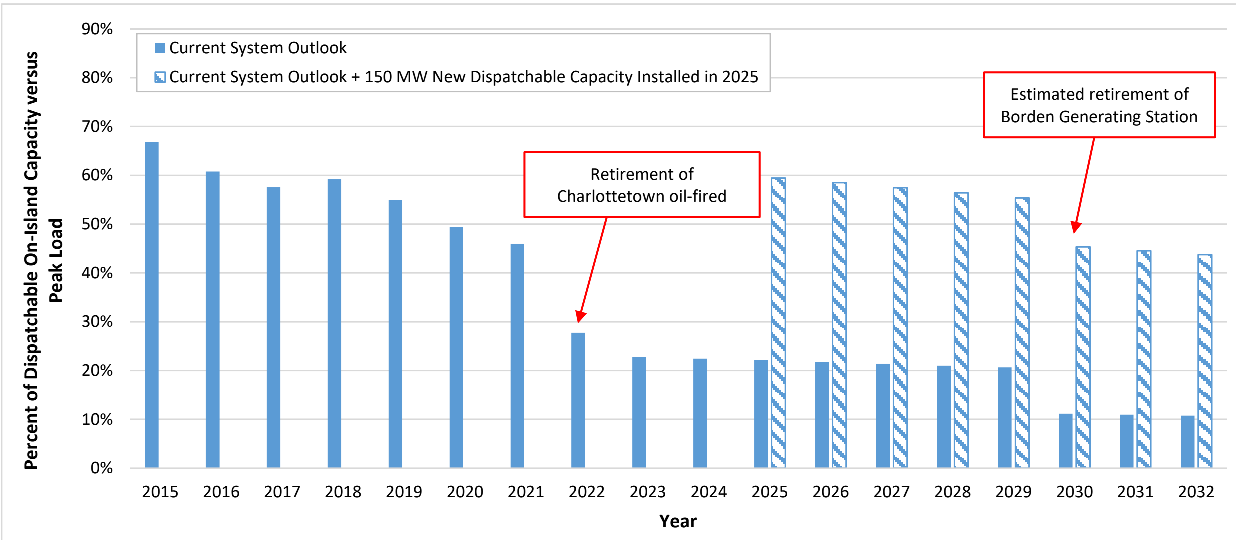
5.1. UPDATED RESOURCE RECOMMENDATIONS

On December 9, 2022, S&L issued the *Capacity Resource Study: Evaluation of Various Technology Options for Maritime Electric Company*. The report ultimately concluded that a portfolio of RICE/CTs, onshore wind, and solar photovoltaic was best suited to help Maritime Electric meet its most critical needs and goals. Based on a review of Maritime Electric's current and forecasted peak load, S&L previously recommended that a minimum of 85 MW of new RICE/CTs with biofuel compatibility should be installed on PEI as soon as possible to reduce the probability of load shed and rolling blackouts in the event of electricity import limits and/or interruptions from the mainland.

The extreme cold weather event that occurred between February 3 to 5, 2023, resulted in record peak load of 395.7 MW, which was over 72 MW higher (22.5%) than the previous peak load of 322.9 MW experienced in January 2022. As a result, S&L has revised its previous recommendation of a minimum of 85 MW of new RICE/CTs with biofuel compatibility to a range of 125 to 150 MW of the same technology, to bring the ratio of dispatchable capacity to peak load back in line with the 50% historical threshold (which would equate the risk of potential load shed in the event of mainland import curtailments to near historical levels). A range of additional capacity was specified because there is uncertainty regarding the future peak load forecast for PEI. The lower end of the recommended range is based on MECL's recently updated internal 10-year peak forecast and the higher end of the range is based on an escalation of the 395.7 MW peak experienced on February 4, 2023. In addition, MECL should continue to prioritize integration of both onshore wind and solar photovoltaic to help meet decarbonization goals, consistent with what was recommended in S&L's original report. Note that even with up to 150 MW of additional dispatchable capacity, there may still be a need for load shed to be implemented if PEI were not able to secure enough electricity imports to fully meet load; however, the additional 125 to 150 MW would help to bring the risk of load shed to be consistent with historical levels.

Figure 5-1 illustrates the ratio of dispatchable on-island generation capacity versus peak load both historically and forecasted through 2032. A second set of data points are included on the figure to illustrate how the ratio of dispatchable capacity versus peak load increases if 150 MW of additional dispatchable capacity is added on PEI in 2025. Note that current estimates for the retirement of the Borden Generating Station (40 MW) is approximately 2030. Additional capacity, beyond the 150 MW assumed in 2025, would have to be added to the system in 2030 to replace Borden's retired 40 MW capacity to maintain a 50% ratio of capacity to peak load. Figure 5-1 does not add any additional capacity to replace Borden; however, it does illustrate the impact of Borden's retirement in terms of the capacity to peak load ratio.

Figure 5-1 — Outlook of Dispatchable On-Island Capacity versus Peak Load



In addition, S&L continues to note that a new BESS demonstration project could help identify the BESS functions/use cases that offer the maximum benefit for the island.

5.1.1. Synchronous Condenser Considerations

Given the large distance between PEI and the large mainland generators, PEI must be self-sufficient in reactive power supply capability, which is necessary for maintaining voltage levels and system stability on PEI. This is an ongoing challenge, especially as more wind generation is added to PEI. A synchronous condenser is an example of electrical equipment than can help improve an electrical system's voltage regulation and overall stability. RICE and CTs have the ability to operate as a synchronous condenser when they are not generating electricity; under this mode of operation, the units use a modest amount of energy from the grid to synchronize (spin), helping to improve the system's electrical performance. The units do not consume fuel when operating as synchronous condensers. The 2020 MECL Integrated System Plan noted that after island load exceeds 350 MW, additional system voltage support (i.e., a synchronous condenser) will be needed on PEI[25]. Previous forecasts of island load estimated that levels higher than 350 MW would not be reached for a number of years; however, given PEI's load nearly reached 400 MW on February 4, 2023, additional system voltage support is needed today.

While both a CT and RICE can be fitted with the appropriate equipment to allow them to function as synchronous condensers when they are not generating electricity, the use of CTs as synchronous condensers is much more common than the use of RICE. In the December 9, 2022, report issued by S&L (*Capacity Resource Study: Evaluation of Various Technology Options for Maritime Electric Company*), S&L considered both CT and RICE options to be virtually equivalent from a technical capability perspective, with RICE being modestly less expensive. However, if MECL wishes to pursue an option with a strong pedigree of synchronous condenser operation, S&L recommends MECL pursue CTs over RICE.

5.1.2. Estimated Costs

Appendix A of this addendum provides a detailed high-level cost estimate of purchasing approximately 170 MW of additional CTs, represented by a 3x0 simple-cycle design with General Electrical LM6000 PF+ SPRINT CT generators (three turbines at a 57.1 MW winter rating each). The estimate includes options for operation exclusively on diesel fuel as well as operation with biodiesel. Other manufacturers make units of similar technical capabilities that MECL could pursue, including varying capacities of CTs and RICE units—the unit types and manufacturers shown in the following table are for illustration and high-level costing comparisons only. S&L recommends biodiesel fuel compatibility to reduce the risk of having a stranded asset in the event government fuel regulations change in the future—biodiesel is considered a renewable fuel by the Canadian government. The cost of equipment related to synchronous condenser operation is also included in this indicative estimate for the CTs (this is not included for the RICE due to the reasons described in Section 5.1.1).

The following table provides a summary of the key operating details and levelized costs for the LM6000 option, along with an alternative RICE design. Additional details and assumptions are noted in Appendix A for the CT design with the RICE details included in the previously report.

[25] Maritime Electric 2020 Integrated System Plan, page 44 and 47

Table 5-1 — Estimated Costs for New CTs/RICE

Title	CT – Aeroderivative		RICE	
	GE LM6000 PF+ SPRINT		Wartsila 20V32	
Fuel Type	Diesel Only	Biodiesel Compatible	Diesel Only	Biodiesel Compatible
Winter Output (MW)	57.1 per turbine	57.1 per turbine	10.6 per engine	9.4 per engine
Net Heat Rate (Btu/kWh)	9,000	9,500	8,400	8,400
Levelized Install Cost (CAD/kW)	1,744	1,817	1,845	2,074
Synchronous Condenser Cost	Included	Included	Not included	Not included

The levelized install cost (dollars per kW) for the LM6000 CT shown above is lower than the smaller RICE design (note that the levelized cost values consider economies of scale associated with the purchase of multiple generators to total approximately 150 MW). Furthermore, the cost for the synchronous condenser is already included for the CT option. However, the RICE design may provide more flexible operation due to the smaller unit capacities, as well as the ability to implement a staggered install schedule over time. As described in S&L's previous report, the RICE units also require less modification to operate on biodiesel fuel. At a capacity of 125–150 MW, along with the known synchronous condenser operational benefits of CTs, either the larger CT design alone, or a portfolio of CTs and RICE, are likely the best options for MECL.

5.2. WIND GENERATION LESSONS LEARNED

During the extreme cold weather event that took place between February 3 and 5, 2023, wind generation dropped substantially because of a number of cascading wind generator and system failures related to the cold temperatures and high wind speed / high wind turbulence. The drop in wind generation resulted in PEI having to import a significant amount of energy from the mainland during the event to avoid load shed. Fortunately, electricity imports, generation produced from the dispatchable generators on PEI, and the remaining wind generation on PEI were able to fully meet the record load experienced on the island; however, PEI came very close to having load shed during the coldest part of the event.

As discussed earlier, S&L had the opportunity to speak with WEICAN during the preparation of this addendum on the topic of what transpired between February 3 and 5, 2023. WEICAN operates several wind turbine generators on PEI for research purposes. During S&L's conversations with WEICAN, it became clear that there are several lessons learned that can and should be shared related to the wind generator and grid operation during the cold weather event between MECL, the wind operators, and the wind turbine original equipment manufacturers. These lessons learned will help to identify various improvements and changes to avoid a similar drop off in wind generator production during a future extreme cold event.

Given these considerations, S&L recommends further information sharing, and/or a technical conference, between MECL, the wind operators, and the wind generator original equipment manufacturers to fully understand what transpired and find solutions to prevent a repeat of the challenges experienced between February 3 and 5, 2023.

APPENDIX A. NEW THERMAL GENERATION COST ESTIMATES

Appendix A contains capital and operations and maintenance estimates for 14x0 and 3x0 simple-cycle designs with Wärtsilä 20V32 RICE and General Electric LM6000 PF+ SPRINT CT generators, respectively. The estimate includes options for operation exclusively on diesel fuel as well as operation with biodiesel. All values in CAD.

Technology	**Reciprocating Internal Combustion Engine**	**Reciprocating Internal Combustion Engine**	**Combustion Turbine - Aeroderivative**	**Combustion Turbine - Aeroderivative**
Unit Type (Representative Manufacturer)	Wartsila 20V32 (14x)	Wartsila 20V32 (14x)	GE LM6000 PF+ SPRINT w/ Sync Condenser (3x)	GE LM6000 PF+ SPRINT w/ Sync Condenser (3x)
Cycle Type	Simple Cycle	Simple Cycle	Simple Cycle	Simple Cycle
Fuel Type	Diesel Fuel	Biodiesel Fuel	Diesel Fuel Only	Biodiesel Fuel Compatible
Net Plant Output (MW) - Summer (27˚C, 47% RH, 0 m)	148.4	131.2	119.7	119.7
Net Plant Output (MW) - Winter (-26˚C, 60% RH, 0 m)	148.4	131.2	171.3	171.3
Net Heat Rate (Btu/kWh) (HHV) (ISO: 15˚C, 60% RH, 0 m	8,400	8,400	9,000	9,500
Project Costs				
Owner Furnished Equipment				
Prime Mover	$ 82,377,000	$ 82,377,000	$ 92,979,000	$ 101,079,000
Emission Control	$ -	$ -	$ -	$ -
Synchronous Condenser	$ -	$ -	$ 11,138,000	$ 11,138,000
Sales Tax	$ 12,357,000	$ 12,357,000	$ 15,617,000	$ 16,832,000
Total Owner Furnished Equipment	**$ 94,734,000**	**$ 94,734,000**	**$ 119,734,000**	**$ 129,049,000**
EPC Costs				
Other Equipment	$ 16,137,000	$ 16,137,000	$ 22,462,000	$ 22,462,000
Diesel/Biodiesel Infrastructure (Fuel Handling and Stora	$ 6,827,000	$ 7,711,000	$ 4,749,000	$ 5,364,000
Materials	$ 26,958,000	$ 26,958,000	$ 10,440,000	$ 10,440,000
Construction Labour	$ 34,490,000	$ 34,490,000	$ 46,567,000	$ 46,567,000
Other Labour	$ 14,954,000	$ 14,954,000	$ 12,126,000	$ 12,126,000
Sales Tax	$ 6,464,000	$ 6,464,000	$ 4,935,000	$ 4,935,000
EPC Contractor Fee	$ 11,646,000	$ 11,646,000	$ 13,261,000	$ 13,856,000
EPC Contingency	$ 16,045,000	$ 16,045,000	$ 17,681,000	$ 18,475,000
Total EPC Costs	**$ 133,521,000**	**$ 134,405,000**	**$ 132,221,000**	**$ 134,225,000**
Total Project Costs	**$ 228,255,000**	**$ 229,139,000**	**$ 251,955,000**	**$ 263,274,000**
Non-EPC Costs				
Project Development	$ 6,676,000	$ 6,676,000	$ 6,611,000	$ 6,711,000
Mobilization and Start-Up	$ 1,335,000	$ 1,335,000	$ 1,322,000	$ 1,342,000
Non-Fuel Inventories	$ 668,000	$ 668,000	$ 662,000	$ 671,000
Owner's Contingency	$ 10,681,000	$ 10,681,000	$ 10,577,000	$ 10,738,000
Electrical Interconnection	$ 6,210,000	$ 6,210,000	$ 6,885,000	$ 6,885,000
Land	$ 2,700,000	$ 2,700,000	$ 2,700,000	$ 2,700,000
Fuel Inventories	$ 15,290,000	$ 13,514,000	$ 16,058,000	$ 16,951,000
Working Capital	$ 2,003,000	$ 2,003,000	$ 1,983,000	$ 2,013,000
Subtotal - Non-EPC Costs w/o Financing Fees	**$ 45,563,000**	**$ 43,787,000**	**$ 46,798,000**	**$ 48,011,000**
Total Non-EPC Costs	**$ 45,563,000**	**$ 43,787,000**	**$ 46,798,000**	**$ 48,011,000**
Overnight Capital Costs ($)	**$ 273,818,000**	**$ 272,926,000**	**$ 298,753,000**	**$ 311,285,000**
Overnight Capital Costs ($/kW-Winter)	$ 1,845	$ 2,074	$ 1,744	$ 1,817

(1) Costs based on EPC contracting approach.
(2) Interconnection and land costs are assumed values.
(3) Property taxes and insurance costs are not included in the above estimate.

Technology	Reciprocating Internal Combustion Engine	Reciprocating Internal Combustion Engine	Combustion Turbine - Aeroderivative	Combustion Turbine - Aeroderivative
Unit Type (Representative Manufacturer)	Wartsila 20V32 (14x)	Wartsila 20V32 (14x)	GE LM6000 PF+ SPRINT w/ Sync Condenser (3x)	GE LM6000 PF+ SPRINT w/ Sync Condenser (3x)
Cycle Type	Simple Cycle	Simple Cycle	Simple Cycle	Simple Cycle
Fuel Type	Diesel Fuel	Biodiesel Fuel	Diesel Fuel Only	Biodiesel Fuel Compatible
Net Plant Output (MW) - Summer (27˚C, 47% RH, 0 m)	148.4	131.2	119.7	119.7
Net Plant Output (MW) - Winter (-26˚C, 60% RH, 0 m)	148.4	131.2	171.3	171.3
Net Heat Rate (Btu/kWh) (HHV) (ISO: 15˚C, 60% RH, 0 m	8,400	8,400	9,000	9,500
Fixed O&M				
Labor - Routine O&M	$ 880,000	$ 880,000	$ 659,000	$ 659,000
Maintenance Materials and Services	$ 190,000	$ 190,000	$ 154,000	$ 154,000
G&A	$ 331,000	$ 331,000	$ 267,000	$ 267,000
Total Fixed O&M ($)	**$ 1,401,000**	**$ 1,401,000**	**$ 1,080,000**	**$ 1,080,000**
Total Fixed O&M ($/kW-year)	$ 9.44	$ 10.68	$ 6.30	$ 6.30
Variable O&M				
Annualized Equipment Maintenance	$ 568,000	$ 568,000	$ 459,000	$ 459,000
VOM (non-fuel)	$ 274,000	$ 274,000	$ 221,000	$ 221,000
Variable O&M - Hours Based ($/MWh)	$ 64.79	$ 73.31	$ 45.34	$ 45.34

O&M expenses assume low utilization (1% capacity factor); thus predominately allocate O&M spend on a variable basis.