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A FORTIS COMPANY

July 24, 2026

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The Island Regulatory and Appeals Commission

Ms. Cheryl Bradley
Island Regulatory and Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Ms. Bradley:

Response to Additional Interrogatories from Commission Staff
On-Island Capacity for Security of Supply Project (UE20742)

Please find attached Maritime Electric Company Limited's ("Maritime Electric" or the "Company") responses to additional interrogatories from Commission Staff with respect to the On-Island Capacity for Security of Supply Project Application and associated Supplemental Filing, filed with the Commission on December 18, 2024, and August 14, 2025, respectively.

Also attached is a request for confidentiality of certain information contained in the responses for the Commission's consideration.

An electronic copy of this submission will be forwarded shortly.

As indicated in Maritime Electric's update on the Accelerated On-Island Capacity Development Solution ("ProEnergy Opportunity") letter submitted on March 20, 2026,[1] and in the Company's responses to interrogatories from Commission Staff submitted on June 10, 2026,[2] the Company retained Energy and Environmental Economics, Incorporated ("E3") to complete a resource adequacy study and calculate the effective load carrying capability ("ELCC") of various resources, including battery energy storage systems ("BESS"). The Maritime Electric Resource Adequacy Study prepared by E3 ("E3 Study") is referenced as part of Maritime Electric's responses and provided as IR-23 - Attachment 1.

The E3 Study's modeling approach is consistent with established practices across North America, including the use of a loss-of-load probability framework and a target loss of load expectation ("LOLE") reliability standard of 0.1 days per year. The analysis evaluates system performance across thousands of simulated years, incorporating a wide range of weather conditions, load variability, renewable output, and random generator outages. The E3 study also provides ELCC results for various capacity resources to enable a direct comparison of costs. ELCC is the key measure because the issue being addressed in this proceeding is capacity, not energy.

The E3 Study found that, "Absent additional resources, in 2030 the [Maritime Electric] system will be exposed to loss-of-load events as frequently as 24 days per year, with individual events ranging from 1 hour to over 24 hours in duration."[3] The year 2030 was selected because it represents the approximate timeframe in which additional on-Island capacity could realistically be commissioned. These results demonstrate the urgent need for additional capacity.

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1 Exhibit M-26, page 2.
2 Exhibit M-29, response to IR-18(c), pages 7-8.
3 E3 Study, page 9.

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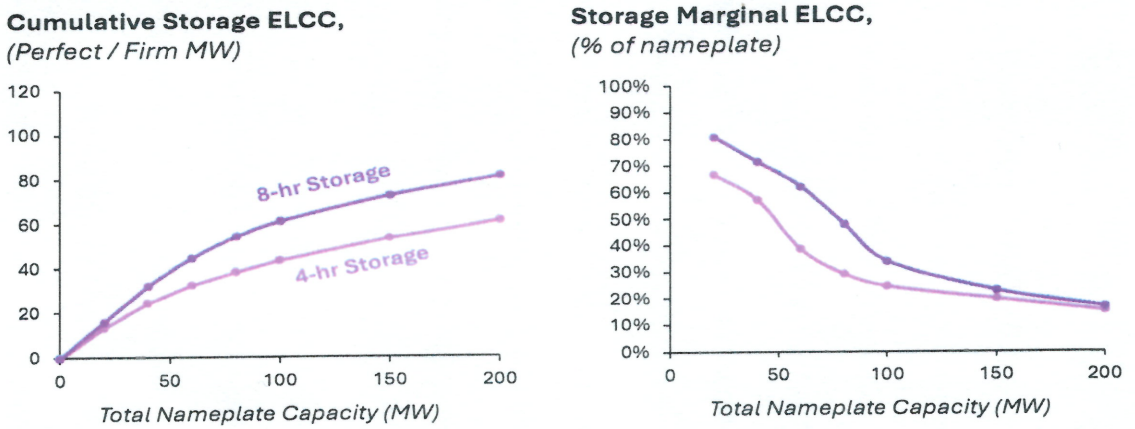
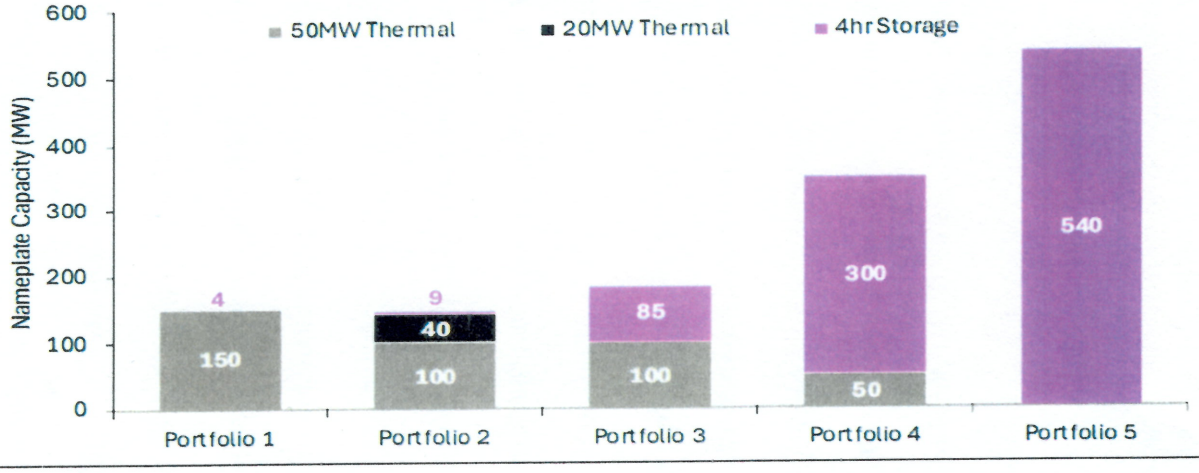
To support Maritime Electric's capacity resource planning, the E3 Study provided ELCC results specific to Maritime Electric's system for various resources, including BESSs. The E3 Study found that, "It would take a very large quantity of storage to fill the entire resource gap, either 390 MW of 8-hr storage or 540 MW of 4-hr storage."[4] This is because the incremental ELCC of BESSs declines relative to nameplate value as the penetration on Maritime Electric's system increases, as illustrated in Figure 1.[5]

FIGURE 1
E3 Study BESS ELCC Results



To achieve a LOLE reliability target of 0.1 days per year, the E3 Study presents several capacity resource portfolio options, which all provide the same combined capacity contribution to Maritime Electric's system by accounting for the ELCC of the various resources. The Portfolios 1 through 5 presented in the E3 Study are shown in Figure 2.[6]

FIGURE 2
E3 Study Capacity Resource Portfolios 1 Through 5



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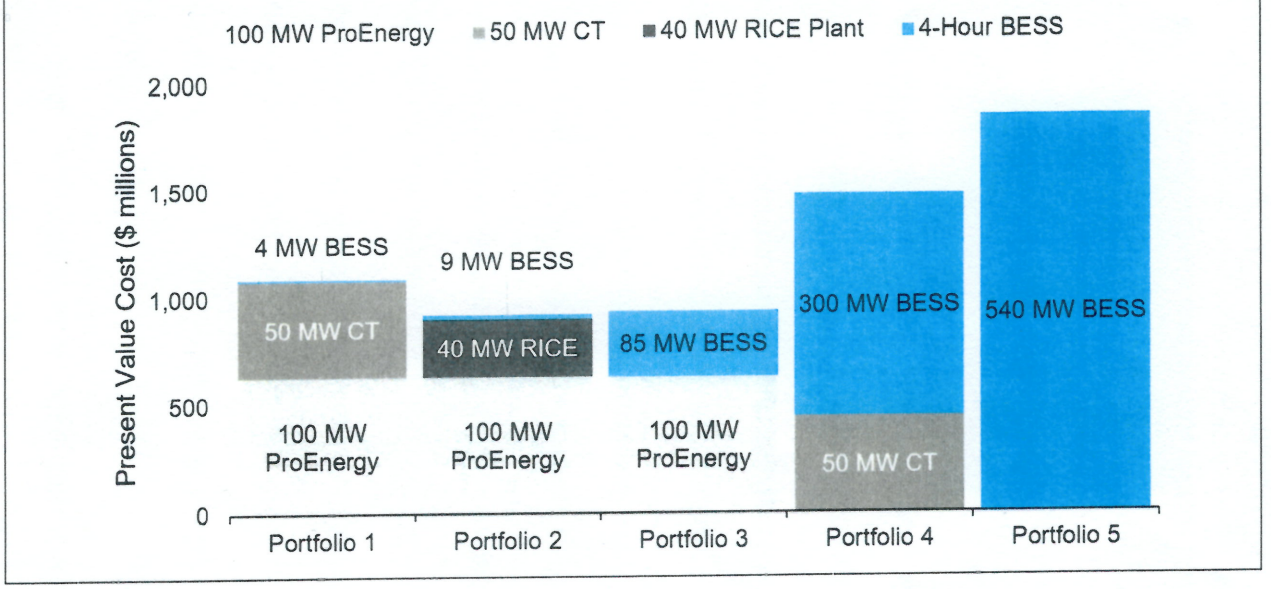
4 E3 Study, page 48.
5 E3 Study, Figure 5-7 (page 48).
6 Derived from the E3 Study, Figure 5-10 (page 54).

All five portfolios shown in Figure 2 have the same combined ELCC and therefore make an equivalent contribution toward achieving Maritime Electric's capacity needs and target LOLE reliability standard. However, portfolios that rely heavily on BESSs, such as Portfolios 4 and 5, require very large BESSs to provide capacity contributions equivalent to thermal capacity resources (e.g., combustion turbines or a reciprocating internal combustion engine ("RICE") plant). This, along with the shorter useful life of a BESS, makes high reliance on BESSs uneconomic for serving the Company's capacity needs.

Using the results of the E3 Study, Maritime Electric has completed a Portfolio Net Present Value Study ("Portfolio NPV Study"), which is referenced as part of Maritime Electric's responses and provided as IR-54 - Attachment 1. The Portfolio NPV Study provides a comprehensive and consistent quantitative comparison of the portfolio options from the E3 Study. By aligning all portfolios on a common ELCC basis, the study enables a direct comparison of capacity resource costs over a 50-year study period, addressing a limitation of earlier Net Present Value ("NPV") analyses. The study also incorporates several annual operating costs and values that were not included in previous NPV analyses, including thermal generation fuel costs, BESS charging costs, and BESS energy arbitrage value.

The results of the Portfolio NPV Study, shown in Figure 3,[7] indicate that portfolios containing the ProEnergy Opportunity provide the lowest overall present value cost. Under the base case, Portfolio 2, which is comprised of the 100 MW ProEnergy Opportunity, a 40 MW RICE plant and a small BESS, yields the lowest present value cost. Portfolio 3, which replaces the RICE plant with a larger BESS, produces a cost outcome that is only marginally higher. In contrast, portfolios with high levels of BESS capacity result in significantly higher costs, reflecting the declining incremental capacity value of storage as penetration increases.

FIGURE 3
Base Case Portfolio NPV Study Present Value Cost Comparison



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7 Portfolio NPV Study, Figure 6 (page 26).

An extensive sensitivity analysis provided in the Portfolio NPV Study confirms the robustness of these findings across a wide range of assumptions,[8] including variations in capital costs, fuel prices, capacity factors and BESS energy arbitrage value. Portfolio 2 and Portfolio 3 remain the lowest-cost options in all scenarios. Overall, the Portfolio NPV Study demonstrates that Portfolio 2 and Portfolio 3, which are anchored by the ProEnergy Opportunity, provide the most cost-effective approach to meeting Maritime Electric's near-term capacity requirements.

Accordingly, Maritime Electric believes it is prudent to proceed with the ProEnergy Opportunity as soon as possible. The Company's evidence demonstrates that the ProEnergy Opportunity represents the most cost-effective and timely solution towards beginning to address the Company's near-term capacity deficit. However, as demonstrated in the E3 Study, the ProEnergy Opportunity addresses only a portion of Maritime Electric's near-term capacity needs. If approved, Maritime Electric intends to immediately begin advancing the next phase of capacity development.

The Company welcomes the opportunity to discuss the merits of the ProEnergy Opportunity, and the evidence put forth by the Company during the upcoming hearing.

Yours truly,

MARITIME ELECTRIC

Michelle Francis
Vice President, Finance & Chief Financial Officer

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Enclosures

8 Refer to the Portfolio NPV Study, Section 5.1 (page 27) for details of the sensitivity analysis.

RESPONSES TO ADDITIONAL INTERROGATORIES FROM COMMISSION STAFF

On-Island Capacity for Security of Supply Project (UE20742)

Submitted July 24, 2026

MARITIME ELECTRIC
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REQUEST FOR CONFIDENTIALITY

DOCKET UE20742

CANADA

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of an Application by Maritime Electric Company, Limited, for Approval of a Supplementary Capital Budget Request for the On-Island Capacity for Security of Supply Project Pursuant to Section 17 of the *Electric Power Act*, RSPEI 1988, c.E-4

REQUEST FOR CONFIDENTIALITY

INTRODUCTION

1. Maritime Electric Company, Limited ("Maritime Electric" or the "Company") is a public utility subject to the *Electric Power Act* engaged in the production, purchase, transmission, distribution, and sale of electricity within Prince Edward Island.

2. On December 18, 2024, Maritime Electric applied for an order of the Island Regulatory and Appeals Commission (the "Commission") approving a supplementary capital budget request for the On-Island Capacity for Security of Supply Project (Exhibit M-1, "the Original Filing").

3. On August 14, 2025, Maritime Electric filed additional evidence detailing a new and time-sensitive opportunity that had arisen (Exhibit M-12, "the Supplemental Filing").

4. Since that time, various procedural steps have been taken in this matter.

5. Most recently, on July 10, 2026, the Commission posed additional staff interrogatories to Maritime Electric (Exhibit C-28, Additional Staff Interrogatories to MECL – On-Island Capacity (July 10, 2026)), and has required a response to those interrogatories by July 24, 2026.

REQUEST FOR CONFIDENTIALITY

6. Maritime Electric hereby requests an order pursuant to *Rule 54* of the Commission's *Rules of Practice and Procedure* (the "*Rules*") directing that certain information in its responses to Exhibit C-28 be treated as confidential. That information includes the Interconnection Agreement with NB Power (IR-39), indicative pricing provided by the New Brunswick Energy Marketing Corporation (IR-46(b)), avoided capacity cost data within the updated rate impact analyses (IR-84), and IR-87(d)), and corporate and employee performance targets and incentive compensation information (IR-88, IR-89, and IR-90).

7. In Maritime Electric's submission, disclosure of this commercially sensitive information would impact the competitive position of Maritime Electric and third parties, as well as Maritime Electric's negotiating position in future negotiations, and would ultimately prejudice ratepayers.

8. Maritime Electric has provided, or will provide, unredacted copies of the relevant materials to the Commission and the Added Party Intervener.

LEGAL PRINCIPLES

OVERVIEW

9. It will be useful to begin with an overview of the relevant legal principles.

10. Documents filed with the Commission are generally placed on the public record. The *Rules* nevertheless provide a framework by which a party may request that a document filed with the Commission be held in confidence. This framework explains what an applicant must do to request confidentiality and what the Commission must consider in deciding the request.

11. The Supreme Court of Canada has also provided direction on the subject of confidentiality orders. In particular, the Court has stated that a discretionary request for confidentiality should typically be granted only to safeguard an important public interest. This direction from the Supreme Court of Canada should inform the application of the framework set out in the *Rules*.

12. Regulators have repeatedly acknowledged that there is an important public interest in ensuring the efficiency and competitiveness of regulated public utilities. A decrease in the efficiency or competitiveness of a regulated public utility can, in turn, cause a rise in the prices paid by customers.

13. The public disclosure of information during a regulatory proceeding can undermine the efficiency and competitiveness of a public utility and thereby harm the public. Tribunals frequently issue confidentiality orders to prevent this harm from arising. The prior decisions of the Commission and similar tribunals provide helpful guidance on the type of information that may permissibly be kept in confidence for this purpose.

14. These principles are explained in greater detail below.

THE RULES PROVIDE THE FRAMEWORK FOR DECIDING A REQUEST FOR CONFIDENTIALITY

15. The framework for making and deciding a request for confidentiality is set out in R*ules 51 to 54*.

16. *Rule 51* provides that a party may request that all or part of a document filed with the Commission be held in confidence. The request must summarize the document, state the reasons for the request, and explain any objection to placing an abridged version of the document on the public record:

> *Rule 51. Request for Confidentiality of Documents*
> *1. A party may request that all or any part of a document be held in confidence by the Commission.*
> *2. Any request for confidentiality shall:*
> *(a) include a summary of the nature of the information in the document;*
> *(b) state:*
> *i. the reasons for the request, including the details of the nature and extent of the specific harm that would result if the document were publicly disclosed; and*
> *ii. any objection to placing an abridged version of the document on the public record and the reasons for such an objection; and*
> *(c) be filed with the Commission and served on the parties.*

3. Where a party has made a request under Rule 51.0(1), the document may, at the discretion of the Commission, be held in confidence.

4. A document that is determined by the Commission to be held in confidence may be considered by the Commission in determining the application or appeal.

17. *Rule 52* provides that a party may file an objection to a request for confidentiality and that the party claiming confidentiality may reply to any objection so filed:

> *Rule 52. Objection to Request for Confidentiality*
>
> *1. A party may object to a request for confidentiality by filing an objection and serving the objection on the parties.*
>
> *2. An objection shall state the reasons:*
>
> *(a) why the party requires disclosure of the document; and*
>
> *(b) why disclosure would be in the public interest.*
>
> *3. The party claiming confidentiality will have an opportunity to reply to any objection.*

18. *Rule 53* provides guidance to the Commission in exercising its discretion to decide a request for confidentiality:

> *Rule 53. Factors Considered*
>
> *When deciding a request for confidentiality, the Commission shall consider:*
>
> *(a) whether the document may disclose matters involving public security;*
>
> *(b) whether the document may disclose sensitive financial, commercial or personal matters in relation to which the desirability of avoiding disclosure in the interest of any person affected outweighs the desirability of adhering to the principle that documents be available to the public; or*
>
> *(c) such other matters the Commission deems appropriate.*

19. Finally, *Rule 54* provides the Commission with broad remedial authority to make an order in response to a request for confidentiality:

> *54. Power of Commission Respecting Confidentiality of Evidence*
>
> *The Commission may:*
>
> *(a) order that the document be held in confidence by the Commission;*
>
> *(b) order that the document be placed on the public record;*

(c) order that an abridged version of the document be placed on the public record;

(d) order that the document be made available to a party to the proceeding, who has a good faith interest in accessing the confidential information and who would not otherwise be in conflict of interest, on such terms as the Commission considers appropriate, including the signing of a confidentiality form approved by the Commission;

(e) order that the document be withdrawn; or

(f) make any other order the Commission may deem to be in the public interest.

20. The breadth of this authority allows the Commission to craft an order that is appropriate in the circumstances of a given case.

THE SUPREME COURT OF CANADA HAS PROVIDED GUIDANCE ON CONFIDENTIALITY ORDERS

21. In *Sierra Club of Canada v. Canada (Minister of Finance)*, the Supreme Court of Canada affirmed that the open court principle is "*inextricably tied*" to the Charter right to freedom of expression. The open court principle means that, as a general rule, the public must be permitted to attend court hearings and read court files. *Sierra Club of Canada v. Canada (Minister of Finance)*, [2002] 2 S.C.R. 522 at 543; *Sherman Estate v. Donovan*, 2021 SCC 25 at para 1.

22. The open court principle applies to "*all judicial proceedings, whatever their nature*". *Sherman Estate v. Donovan,* 2021 SCC 25 at para 44. In practice, this means that the principle applies to all court proceedings, but not necessarily to all administrative proceedings.

23. In cases where the open court principle does apply, a discretionary order to limit court openness will violate s. 2(b) of the Charter unless the person seeking the order establishes that:

(1) court openness poses a serious risk to an important public interest;

(2) the order sought is necessary to prevent this serious risk to the identified interest because reasonably alternative measures will not prevent this risk; and

(3) as a matter of proportionality, the benefits of the order outweigh its negative effects.

Sherman Estate v. Donovan, 2021 SCC 25 at para 38.

24. When these requirements are satisfied, a discretionary order limiting court openness will not violate s. 2(b) of the Charter, even if the proceeding is one to which the open court principle applies.

DECISIONS FROM OTHER JURISDICTIONS SUGGEST THAT THE OPEN COURT PRINCIPLE APPLIES TO THIS REQUEST

25. There is debate about whether the open court principle applies to administrative tribunals. Lower courts have held that it does apply when tribunals hold "*adjudicative hearings*" (*Toronto Star v. AG Ontario*, 2018 ONSC 2586 at para 7) but does not apply when they perform other functions (*Fraser v. Canada (Public Safety and Emergency Preparedness)*, 2021 FC 821 at para 90).

26. This raises the question of whether this request for confidentiality is being made in the course of an "*adjudicative hearing*" to which the open court principle applies. No binding precedent is directly on point, but some decisions are instructive:

(a) The Nova Scotia Court of Appeal has indicated that the open court principle applies to an application by a public utility for approval of a capital expenditure. *Cape Breton Explorations Ltd. v. Nova Scotia (Attorney General)*, 2013 NSCA 134 at paras 23–24 and 42(c).

(b) A majority of the British Columbia Court of Appeal has indicated that the open court principle applies to an application by a public utility for approval of an energy purchase agreement. *Joint Industry Electricity Steering Committee v. British Columbia Utilities Commission*, 2005 BCCA 330 at para 49 per Rowes J.A. and at para 101 per Levin J.A.

(c) The Alberta Utilities Commission has indicated that the open court principle applies to an application by two public utilities for permission to construct a substation and two transmission lines. *AltaLink Management Ltd.*, Re, 2011 CarswellAlta 1797, Appendix 3.b at para 30.

27. These decisions, although not binding on the Commission, do suggest that the open court principle applies to the present matter.

THE FRAMEWORK IN THE RULES SHOULD BE SUPPLEMENTED WITH REFERENCE TO THE DIRECTION FROM THE SUPREME COURT OF CANADA

28. Assuming, then, that the open court principle described in *Sierra Club* does apply to the hearing in which this request is being made, the Commission must determine how to integrate that principle into the framework set out in the *Rules*.

29. Decisions from the Nova Scotia Utility and Review Board (the "NS Review Board") provide helpful guidance. The NS Review Board treats its rules of practice and procedure as being "*in essence a codification*" of the open court principle described in *Sierra Club. Nova Scotia Power Inc.*, Re, 2014 NSUARB 5 at para 11; *Friends of Harmony, Camden, Greenfield and Surrounding Areas*, Re, 2015 NSUARB 140 at para 12. In practice, this means that the NS Review Board decides a request for confidentiality by applying its own rules and by referring, as needed, to the direction set out in *Sierra Club*. A good example of this is found in *Nova Scotia Power Inc.*, Re, 2014 NSUARB 5 at paras 25–43.

30. The approach of the NS Review Board is relevant to the present matter because the rules of the NS Review Board for deciding a request for confidentiality are substantially similar to those of the Commission. *Board Regulatory Rules*, NS Reg 235/2005, s. 12. A side-by-side comparison reveals that these sets of rules are nearly identical in stating the requirements for making, and the factors for assessing, a request for confidentiality. Given the similarity between these sets of rules, the Commission can, on this point, take guidance from the NS Review Board.

31. It is worth pausing to highlight the direction from *Sierra Club* that should supplement the Commission's application of the *Rules*.

32. The first point of direction relates to the "*interest*" that must be identified to justify granting a request for confidentiality. *Sierra Club* provides that a person seeking to limit the open court principle must establish that court openness poses a serious risk to an important public interest. *Sierra Club* at 544; *Sherman Estate* at para 38. In other words, court openness should not be limited merely to protect the private interests of the parties.

33. The second point of direction relates to the evidence that must be adduced to show that openness poses a serious risk to an important public interest. The Supreme Court has stressed that the tribunal should not be satisfied with too little but also should not require too much. On the one hand, a confidentiality order should not issue on the basis of "*impermissible speculation*" about the risks that will be created by tribunal openness. *Sherman Estate* at para 97. On the other hand, parties requesting confidentiality are not required to adduce "*direct evidence*" of the risks in question. *Sherman Estate* at para 97. A middle ground will suffice: the tribunal may permissibly grant a request for confidentiality on the basis of the "*logical inferences*" that can reasonably be drawn from the circumstances. *Sherman Estate* at para 97.

34. The third and final point of direction relates to alternatives. A tribunal deciding a request for confidentiality should ask whether there are other, "*reasonably alternative*" measures that would prevent the risk to an important public interest. The confidentiality order should issue only if no "*reasonably alternative*" measures are available. *Sherman Estate* at para 97.

35. This direction from the Supreme Court of Canada supplements the framework in the *Rules*.

There is an Important Public Interest in the Efficiency and Competitiveness of Regulated Public Utilities

36. As noted above, *Sierra Club* directs that a confidentiality order should issue only to protect an important public interest.

37. Tribunals have repeatedly recognized that there is an important public interest in protecting the efficiency and competitiveness of regulated public utilities. A decrease in the efficiency or competitiveness of a regulated public utility can, in turn, cause a rise in the prices paid by the customers of the utility. The public has an interest in keeping efficiency up and costs down. See, e.g., *Nova Scotia Power Inc.*, Re, 2012 NSUARB 137 at para 5; *Nova Scotia Power Inc.*, Re, 2014 NSUARB 5 at para 28; *Nova Scotia Power Inc.*, Re, 2020 NSUARB 121 at para 9; *Nova Scotia Power Inc.*, Re, 2022 NSUARB 2 at para 114.

The Disclosure of Confidential Information in the Course of a Regulatory Proceeding may Harm the Efficiency and Competitiveness of a Regulated Public Utility

38. The public interest in ensuring that public utilities are efficient and competitive can be harmed by the disclosure of confidential business information in the course of a regulatory proceeding. The NS Review Board has succinctly described this risk in noting that the regulatory process itself could harm consumers by requiring the indiscriminate disclosure of a public utility's financial or commercial information:

> "*There is a significant public interest in not having the regulatory process itself create undue costs to NS Power, and by extension the consumers of its regulated monopoly service. In other words, disclosure of financial or commercial information which undermines NS Power's ability to obtain goods and services at the lowest possible costs impacts NS Power's customers, which include most businesses and residents of the province. That said, there is still a balancing act to be performed between a demonstrable risk of harm and the transparency of a public process.*" *Nova Scotia Power Inc.*, Re, 2022 NSUARB 2 at para 114.

39. Tribunals have recognized a variety of ways in which disclosure of financial or commercial information in the course of a regulatory proceeding could harm the competitiveness and efficiency of a public utility:

(a) In some cases, the disclosure of information could compromise the position of a public utility in ongoing negotiations. On this basis, information has been kept confidential. Commission Order UE93-10.

(b) In some cases, the disclosure of information could "*advantage*" a public utility's counterparts in future negotiations. On this basis, information has been kept confidential. *Nova Scotia Power Inc.*, Re, 2020 NSUARB 121 at para 9.

(c) In some cases, the disclosure of information could undermine the obligations or representations that the public utility has made to third parties in respect of that information (e.g., an obligation or representation that the information would be kept in confidence). The disclosure of such information could damage the public utility's relationship with that third party and make third parties in general less willing to deal with the public utility in the future. On this basis, information has been kept

confidential. *Nova Scotia Power Inc.*, Re, 2014 NSUARB 5 at para 30, aff'd in *Cape Breton Explorations Ltd. v. Nova Scotia (Attorney General), 2015 NSCA 35* at para 163.

40. These examples evince a general principle: a confidentiality order may issue to prevent the disclosure of information that could undermine the efficiency or competitiveness of a public utility and thereby harm the utility's customers.

PRIOR DECISIONS BY THE COMMISSION PROVIDE GUIDANCE ON THE PROPER APPROACH TO A REQUEST FOR CONFIDENTIALITY

41. The Commission has decided requests for confidentiality in prior applications. Although a tribunal is not bound by prior decisions in the same sense that courts are bound by stare decisis, parties appearing before a tribunal are nevertheless "*entitled to expect that like cases will generally be treated alike*". *Canada (Minister of Citizenship and Immigration) v. Vavilov*, 2019 SCC 65 at para 129. For this reason, prior decisions by the Commission provide helpful guidance on the type of information that may be received and kept in confidence by the Commission. Notable examples include the following:

(a) In Order UE93-10, the Commission permitted Maritime Electric to keep confidential the data supporting a certain proposal to increase its generating capacity. The data was kept confidential to prevent "*compromis[ing] the Company's negotiating position*".

(b) In Order UE93-11, Maritime Electric applied for a number of amendments to its General Tariff. The Company filed information on overall executive compensation in response to Commission Staff interrogatories but requested that the details be examined on a confidential basis. Accordingly, the Commission reviewed these expenses and held an in-camera hearing with the Company's President. Based on this review, the Commission accepted the amounts budgeted by the Company.

(c) In Order UE13-03, the Commission permitted Maritime Electric to file in confidence a Renewable Energy Purchase Agreement that contained "*proprietary information*".

(d) In Order UE19-03, the Commission permitted the Prince Edward Island Energy Corporation to file a Service Delivery Agreement on a confidential basis.

(e) In Order UE25-07, as varied by UE25-07A, the Commission granted confidentiality in respect of commercially sensitive information relating to the On-Island Capacity for Security of Supply Project in this proceeding, including information relating to capacity pricing and avoided capacity costs. Order UE26-03 updated and reaffirmed that confidentiality treatment.

42. These prior decisions confirm that the Commission's approach to confidentiality orders is consistent with the approach of other tribunals with similar mandates, and demonstrate that the Commission has itself recognized the sensitivity of the categories of information at issue in this request.

APPLICATION TO THE PRESENT REQUEST

43. Maritime Electric submits that the material identified in this request falls squarely within the framework established by the *Rules*, as supplemented by the direction from *Sierra Club*, and is consistent with the Commission's prior practice. The specific submissions in respect of each interrogatory response are set out below.

IR-39: INTERCONNECTION AGREEMENT BETWEEN MARITIME ELECTRIC AND NB POWER

44. IR-39 requests that Maritime Electric provide the most recent copy of the Interconnection Agreement between Maritime Electric and NB Power.

45. The Interconnection Agreement is a bilateral commercial agreement between Maritime Electric and NB Power governing the terms upon which Maritime Electric has access to transmission capacity across the New Brunswick–Prince Edward Island interconnection. The agreement contains commercially sensitive terms, including pricing, capacity entitlements, operational obligations, and conditions of service, that are proprietary to both parties. The Interconnection Agreement is, accordingly, precisely the type of sensitive commercial document that *Rule 53(b)* contemplates may be kept in confidence.

46. The Commission has previously recognised the Interconnection Agreement as a confidential document. In Order UE25-07, as varied by UE25-07A, and as reaffirmed by Order UE26-03, the Commission granted confidentiality in relation to evidence in this proceeding that touched upon the commercial terms of the arrangements between

Maritime Electric and NB Power. Maritime Electric submits that the Interconnection Agreement itself falls squarely within the scope of those orders.

47. Applying the *Sierra Club* framework: first, the disclosure of the Interconnection Agreement poses a serious risk to the important public interest in maintaining the efficiency and competitiveness of Maritime Electric. Public disclosure of the agreement's pricing and commercial terms would compromise the negotiating positions of both Maritime Electric and NB Power in future negotiations for interconnection access and related commercial arrangements, and would advantage Maritime Electric's counterparties in those negotiations, consistent with the types of harm identified in Order UE93-10 and in *Nova Scotia Power Inc.*, Re, 2020 NSUARB 121 at para 9. This risk flows logically from the circumstances and does not require direct evidence. Second, there is no reasonably alternative measure that would prevent this risk: the nature of the harm is such that any public disclosure of the agreement's commercial terms would be prejudicial. Third, the benefit to ratepayers of maintaining Maritime Electric's negotiating position outweighs the incremental transparency benefit of public disclosure, particularly where the Commission and the added party intervener will have full access to the unredacted document.

IR-46(B): INDICATIVE PRICING FROM NEW BRUNSWICK ENERGY MARKETING CORPORATION

48. IR-46(b) requests that Maritime Electric provide the indicative price of capacity from NB Power, together with supporting documentation or confirmation from NB Power. Maritime Electric's response to this interrogatory will include a bid received from the New Brunswick Energy Marketing Corporation ("NBEM") submitted in response to a recent request for proposals issued by Maritime Electric. Maritime Electric requests that this document be redacted in its entirety from the public record.

49. NBEM is the electricity marketing entity for NB Power, and the bid it submitted to Maritime Electric constitutes a confidential commercial offer made in the context of a competitive procurement process. The bid contains commercially sensitive pricing information, capacity terms, and contractual conditions that fall squarely within the category of "*sensitive financial, commercial… matters*" contemplated by *Rule 53(b)*.

50. The Commission has, on multiple prior occasions, recognised that pricing information contained in energy purchase agreements and capacity contracts between Maritime Electric and NB Power warrants confidential treatment. In Orders UE25-07, as varied by UE25-07A (and updated in UE26-03), all issued in this proceeding, the Commission recognised that information relating to off-Island capacity procurement pricing should be withheld from public disclosure. In Order UE13-03, the Commission similarly permitted Maritime Electric to file a Renewable Energy Purchase Agreement in confidence because it contained "*proprietary information*". The NS Review Board has noted that a "*frequent*" use of confidentiality rules is to "*permit NS Power to file fuel contracts and other power purchase arrangements in confidence to protect NS Power (and thereby ratepayers) in ensuring that NS Power can obtain competitive fuel prices*", and that "*disclosing these contracts would advantage fuel suppliers in the bidding process*". *Nova Scotia Power Inc.*, Re, 2020 NSUARB 121 at para 9.

51. Applying the *Sierra Club* framework: first, the public disclosure of the NBEM bid poses a serious risk to the important public interest in the competitiveness of Maritime Electric's capacity procurement. Disclosure of a supplier's bid pricing would advantage that supplier, and other suppliers, in any future procurement process, would deter future counterparties from making candid proposals to Maritime Electric, and would ultimately harm ratepayers by limiting the Company's ability to procure off-Island capacity on the best available terms. These risks flow logically from the circumstances and are corroborated by the consistent treatment of such materials by this Commission and comparable regulators. Second, no reasonably alternative measure would prevent this risk: the harm flows from any public disclosure of the pricing terms. Third, the benefits to ratepayers of protecting Maritime Electric's procurement position outweigh the incremental transparency benefit of public disclosure.

IR-84: UPDATED IMPACT ON RATE BASE, REVENUE REQUIREMENT, AND CUSTOMER RATES (AVOIDED CAPACITY COSTS)

52. IR-84 requests that Maritime Electric update its financial analysis — specifically the Impact on Rate Base, Revenue Requirement and Customer Rates — under a series of specified scenarios. The response to IR-84 will necessarily include avoided capacity costs, being the forecast costs that Maritime Electric would avoid by building on-Island capacity rather than purchasing equivalent capacity from off-Island sources.

53. The Commission has previously ruled, in Order UE25-07, as varied by UE25-07A (and updated in Order UE26-03), that avoided capacity costs — specifically described in those Orders as lines two and three, being the avoided capacity costs and operating expense — may be redacted from the public version of Maritime Electric's financial evidence. The avoided capacity costs embedded in the IR-84 analysis reflect the pricing of capacity procurement from off-Island sources, including the terms of existing and potential arrangements with NB Power and other counterparties. Their public disclosure would be equally prejudicial for the reasons identified in those orders.

54. Accordingly, Maritime Electric requests that the Commission confirm that its prior ruling permitting the redaction of avoided capacity costs extends to the updated financial analysis to be filed in response to IR-84, and that the publicly filed version of Maritime Electric's response may redact those line items consistent with the Commission's previous direction.

IR-87(D): UPDATED NET PRESENT VALUE AND RATE IMPACT ANALYSES (AVOIDED CAPACITY COSTS)

55. IR-87 requests that Maritime Electric update the Net Present Value analysis and the Impact on Rate Base, Revenue Requirement and Customer Rates analyses filed in response to IR-16 based on specified assumptions regarding annual operating hours of the proposed combustion turbines. IR-87(d) specifically requests that those analyses be updated assuming avoided off-Island capacity costs that are 10%, 25%, and 50% lower than assumed in the Application.

56. The response to IR-87(d) will necessarily include avoided capacity costs—being the forecast costs that Maritime Electric would avoid by building on-Island capacity rather than purchasing equivalent capacity from off-Island sources—presented under each of those sensitivity scenarios. Avoided capacity costs are, by their nature, derived from the pricing of capacity procurement arrangements with off-Island counterparties, including NB Power.

57. The Commission has previously ruled, in Order UE25-07, as varied by UE25-07A (and updated in Order UE26-03), that avoided capacity costs—specifically described in those Orders as lines two and three, being the avoided capacity costs and operating expense—may be redacted from the public version of Maritime Electric's financial evidence. The rationale for that ruling applies with equal force to the sensitivity analyses required by IR-87(d): each scenario presents avoided capacity cost figures in absolute and comparative

terms, and their public disclosure would reveal the same commercially sensitive procurement pricing information that the Commission has already recognized warrants protection.

58. Accordingly, Maritime Electric requests that the Commission confirm that its prior ruling permitting the redaction of avoided capacity costs extends to the updated analyses to be filed in response to IR-87(d), and that the publicly filed version of Maritime Electric's response may redact those line items consistent with the Commission's previous direction.

IR-88: CORPORATE PERFORMANCE TARGETS

59. IR-88 asks whether Maritime Electric has corporate performance targets or objectives, and if so, requests that the Company provide its corporate performance targets or objectives applicable from 2024 to the present and explain how they relate to the proposed project.

60. Maritime Electric submits that its corporate performance targets and objectives constitute confidential commercial and management information within the meaning of *Rule 53(b)* and should be afforded confidential treatment.

61. First, corporate performance targets reflect the Company's internal strategic priorities, management direction, and operational benchmarks. These metrics are developed through an internal planning process and are tailored to the Company's specific regulatory, financial, and operational circumstances. Their public disclosure would reveal proprietary management strategy, expose the Company's internal decision-making framework to its commercial counterparties and competitors, and undermine the integrity of the Company's internal planning processes going forward.

62. Second, the Commission has itself recognized the sensitivity of executive and management compensation and performance information in prior proceedings. In Order UE93-11, the Commission agreed to examine executive compensation on a confidential basis, holding an in-camera hearing rather than placing the details on the public record. Similarly, Commission Staff addressed interrogatories concerning executive compensation on a confidential basis in a prior capital budget proceeding (Exhibit C-10, Confidential Additional Interrogatories from Commission Staff re Executive Compensation, April 4, 2019). These precedents directly support the confidential treatment of corporate performance targets.

63. Third, the relevance of corporate performance targets to the prudency of a specific capital expenditure decision — the core question before the Commission in this proceeding — is indirect at best, and any marginal relevance is outweighed by the commercial sensitivity of the information. To the extent the Commission considers it relevant to understand whether Maritime Electric's corporate objectives align with the interests of ratepayers in pursuing this project, that question can be addressed at a high level of generality in the public version of Maritime Electric's response without exposing the specific targets, metrics, or thresholds that constitute the confidential substance of the corporate performance program.

64. Applying the *Sierra Club* framework: public disclosure of Maritime Electric's corporate performance targets poses a serious risk to the important public interest in the efficiency and competitiveness of a regulated public utility, by revealing proprietary strategic and management information to commercial counterparties and competitors. That risk flows logically from the nature of the information. No reasonably alternative measure would prevent this harm, as it is the public disclosure itself that is the source of the prejudice. The benefit to ratepayers of protecting Maritime Electric's strategic position outweighs the incremental transparency benefit, particularly where the Commission and qualified parties will have access to the unredacted information.

IR-89: PERSONAL PERFORMANCE TARGETS, CORPORATE PERFORMANCE TARGETS, AND INCENTIVE PLANS

65. IR-89 asks whether Maritime Electric maintains personal performance targets, corporate performance targets, or incentive plans applicable to its employees, and if so, requests the applicable targets, objectives, and incentive measures for employees participating in an incentive compensation plan from 2024 to the present.

66. Maritime Electric submits that this information constitutes both "*sensitive financial*" and "*personal matters*" within the meaning of *Rule 53(b)* and should be afforded confidential treatment.

67. First, individual and group employee performance targets and incentive plans constitute sensitive employment-related information. The disclosure of specific performance metrics and incentive structures applicable to individual employees or employee groups raises serious concerns regarding employee privacy and the confidentiality of the employment

relationship. Employees have a reasonable expectation that the terms and structure of their compensation arrangements — including performance targets that directly determine their remuneration — will not be placed on a public regulatory record. This is precisely the type of "*personal matters*" that *Rule 53(b)* identifies as a basis for withholding information from public disclosure.

68. Second, the specific design of Maritime Electric's incentive compensation programs constitutes proprietary human resources information. The metrics, weighting, thresholds, and payout structures embedded in those programs reflect the Company's internal compensation philosophy and management strategy, and their public disclosure would disadvantage the Company in its labour market and competitive environment.

69. Third, as a matter of regulatory principle, the question of whether a utility's incentive compensation structure creates appropriate management incentives is distinct from the question of whether a specific capital project is prudent and in the public interest. To the extent the Commission wishes to understand how Maritime Electric's incentive structure relates to the proposed project, that question can be addressed on a confidential basis without exposing the detail of individual or group compensation arrangements to public disclosure.

70. Fourth, as noted above in respect of IR-88, the Commission has previously recognized in Order UE93-11 that executive and management compensation information warrants confidential treatment, and Maritime Electric submits that the same principle applies with equal force to employee incentive compensation plans and personal performance targets.

71. Applying the *Sierra Club* framework: the public disclosure of employee incentive compensation and personal performance targets poses a serious risk to the important public interests in both employee privacy and the operational competitiveness of Maritime Electric. The risks flow logically from the nature of the information. No reasonably alternative measure would prevent this harm. The benefits of protection outweigh the incremental transparency benefit of public disclosure.

IR-90: IMPACT OF PROJECT APPROVAL ON EMPLOYEE COMPENSATION OR BONUSES

72. IR-90 asks whether approval or denial of this Application will affect the compensation, incentive compensation, bonus, or other financial remuneration of any Maritime Electric

employee, and if so, requests an explanation of how the employee's compensation would be affected, a quantification of the financial impact (if possible), and an explanation of whether such compensation is proposed to be recovered through customer rates.

73. Maritime Electric submits that the response to IR-90 should be maintained on a confidential basis for reasons that overlap substantially with those advanced in respect of IR-89, and that the information falls within the category of "*sensitive financial*" and "*personal matters*" contemplated by *Rule 53(b)*.

74. The disclosure of whether, and to what extent, specific employees or categories of employees would receive differential compensation depending on the outcome of a regulatory proceeding raises significant privacy concerns. To the extent that individual employees' compensation is contingent upon the outcome of this Application — whether through performance-based bonuses, incentive plans, or otherwise — the public disclosure of those linkages and the quantification of their financial impact would effectively disclose personal compensation information about identifiable individuals.

75. Moreover, there is an inherent risk that public disclosure of compensation linkages to regulatory outcomes could give rise to unfounded inferences or perceptions regarding the motivations of the Company's management in pursuing regulatory applications, which would be neither fair to the individuals concerned nor conducive to the integrity of the regulatory process.

76. Maritime Electric notes that to the extent any portion of incentive compensation is or may be proposed to be recovered through customer rates, that question — which goes to ratemaking — can be addressed in a manner that is sufficient for the Commission's purposes without requiring the public disclosure of individual or group compensation details. The Commission's oversight function in relation to the prudency of costs proposed to be recovered through rates does not require that compensation arrangements be placed on the public record; it requires only that the Commission have sufficient information, on whatever basis is appropriate, to satisfy itself that the costs in question are reasonable.

CONCLUSION

77. In summary, Maritime Electric submits that the material identified above — being the Interconnection Agreement with NB Power (IR-39), the NBEM bid pricing (IR-46(b)), the

avoided capacity cost components of the updated financial analyses (IR-84), and IR-87(d)), the corporate performance targets and objectives (IR-88), the employee incentive compensation programs and personal performance targets (IR-89), and the details of any compensation impacts arising from the outcome of this Application (IR-90) — should remain confidential.

78. Maritime Electric objects to placing an abridged version of this material on the public record. In Maritime Electric's view, the information at issue cannot be abridged or redacted in a way that would preserve confidentiality and at the same time be of assistance to the public.

79. Accordingly, Maritime Electric submits that the material identified above should be disclosed to the Commission and to the added Party or Intervener, but should otherwise remain confidential and not be placed on the public record.

All of which is respectfully submitted.

Dated at Charlottetown, Prince Edward Island, this 24th day of July, 2026.

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MARITIME ELECTRIC
A FORTIS COMPANY
All our energy.
All the time.

AFFIDAVIT

CANADA

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 17(1) of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for the approval of a 2024 Supplemental Capital Budget Request for the On-Island Capacity for Security of Supply Project.

AFFIDAVIT

I, T. Michelle Francis of Emyvale, in Queens County, Province of Prince Edward Island, MAKE OATH AND SAY AS FOLLOWS:

1. I am the Vice President, Finance and Chief Financial Officer for Maritime Electric Company, Limited and as such have personal knowledge of the matters deposed to herein, except where noted, in which case I rely upon the information of others and in which case I verily believe such information to be true.

2. I prepared or supervised the preparation of the attached Interrogatory responses and to the best of my knowledge and belief the responses are true in substance and in fact.

SWORN TO at Charlottetown,
Prince Edward Island, the 24th
day of July, 2026.

A Commission for taking affidavits in the
Supreme Court of Prince Edward Island

T. Michelle Francis

MARITIME ELECTRIC
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All our energy.
All the time.

INTERROGATORIES

The Prince Edward Island Regulatory and Appeals Commission (the "Commission"), in assessing the Application by Maritime Electric Company, Limited ("Maritime Electric" or "MECL") for approval of the On-Island Capacity for Security of Supply Project (the "Application"), requests responses to the following interrogatories from Maritime Electric:

Contingency Planning

IR-23 Please explain the contingency or contingencies that justify additional on-Island capacity at this time (i.e. disconnection from mainland, extreme weather events, etc.).

a. How likely are each of these contingencies to occur?

b. Have these contingencies previously resulted in a service interruption or load shedding for MECL customers? If so, what was the frequency, duration and impact of the interruption?

Response:

a. The need for additional on-Island capacity is not justified based on any individual contingency event, rather, it is justified by insufficient capacity resources to meet Maritime Electric's capacity requirements (i.e., a capacity deficit). Refer to Table 10 of the Supplemental Capital Budget Request Application for the On-Island Capacity for Security of Supply Project ("December 2024 Application"),[1] which demonstrates the extent of the Company's capacity deficit. An update to Table 10 is provided in the response to IR-47.

Section 5.3 of the December 2024 Application describes how Maritime Electric calculates its capacity requirement.[2] The capacity requirement includes a planning reserve margin of 15 per cent, which is described in Section 5.3.4.[3] Section 5.3.4 explains that the "planning reserve is a fixed amount of generating capacity that a utility is required to reserve to account for extreme system peaks or the unplanned failure of a generator [i.e., a forced outage]."

Maritime Electric's 15 per cent planning reserve requirement is derived from regional planning reserve requirements, calculated by the Northeast Power Coordinating Council ("NPCC"). The magnitude of the regional planning reserve requirement is based on a loss of load expectation ("LOLE") reliability target of one day in 10 years (i.e., 0.1 days per year), on a probabilistic basis.[4] Determination of the planning reserve requirement for the region, and Maritime Electric's share of that requirement, is therefore based on a probabilistic analysis of simulated loads and generator forced outage events. Of note, partial or full disconnections from the mainland do not form part of Maritime Electric's planning reserve requirement of 15 per cent.

As indicated in Maritime Electric's update on the Accelerated On-Island Capacity Development Solution ("Accelerated Capacity Solution" or "ProEnergy Opportunity") letter

1 Exhibit M-1, page 45.
2 Exhibit M-1, page 40.
3 Exhibit M-1, page 43.
4 Refer to Exhibit M-1, footnote 66, page 43.

submitted on March 20, 2026,[5] and in the Company's responses to interrogatories from Commission Staff submitted on June 10, 2026,[6] the Company retained Energy and Environmental Economics, Incorporated ("E3") to complete a resource adequacy study and calculate the effective load carrying capability ("ELCC") of various resources, including battery energy storage systems ("BESS"). The Maritime Electric Resource Adequacy Study prepared by E3 ("E3 Study") is provided as IR-23 - Attachment 1.

The E3 Study applies probabilistic resource adequacy modeling consistent with established practices across North America, including the use of a loss-of-load probability framework and a target LOLE reliability standard of 0.1 days per year. The analysis evaluates system performance across thousands of simulated years, incorporating a wide range of weather conditions, load variability, renewable output, and random generator outages based on observed forced outage rates to produce a statistically robust expectation of system reliability. The E3 Study also applies an ELCC framework to evaluate the contribution of different resources to system reliability and determine capacity requirements.

The E3 Study found that, "absent additional resources, in 2030 the [Maritime Electric] system will be exposed to loss-of-load events as frequently as 24 days per year, with individual events ranging from 1 hour to over 24 hours in duration."[7] To achieve a LOLE reliability target of 0.1 days per year, an additional 115 megawatts ("MW") of perfect capacity (i.e., ELCC) is required by 2030.[8] According to the E3 Study, "Perfect capacity (PCAP) is the amount of a hypothetical, perfectly reliable resource — one available 100% of the time with no outages — that a given set of resources is equivalent to for reliability purposes, i.e., installed capacity derated by each resource's reliability contribution (ELCC)."[9]

b. In responding to this question, Maritime Electric notes that all customer outages result from some form of contingency event. For the purposes of this response, however, the Company has interpreted "load shedding" to mean the curtailment of customer load due to insufficient generation or import capability, rather than an inability to deliver available electricity to customers.

Historically, instances where firm customer load was shed due to inadequate supply (i.e., insufficient generation or import capability) have been limited to periods involving partial or full disconnections from the mainland, which significantly reduced the amount of off-Island capacity available to serve Prince Edward Island ("PEI") load. Refer to Maritime Electric's response to IR-8 from Synapse Energy Economics Inc. ("Synapse"),[10] which provides a detailed listing of these events, including the date, duration, cause, and resulting loss of load.

Currently, however, due to a lack of additional capacity to purchase from off-Island and in the absence of additional capacity installed on-Island, the Company has a capacity deficit,

5 Exhibit M-26, page 2.
6 Exhibit M-29, response to IR-18(c), pages 7-8.
7 IR-23 – Attachment 1 - E3 Study, page 9.
8 IR-23 – Attachment 1 - E3 Study, Section 5.1, page 41.
9 IR-23 – Attachment 1 - E3 Study, footnote 2, page 9.
10 Exhibit M-6, page 15.

which significantly increases the risk of load shedding events due to any individual or combination of contingency events. As a result, the lack of load shedding events in the past is not indicative of current conditions and should not be relied upon to predict load shedding events in the present or future.

IR-24 There has only been one incident of full disconnection from New Brunswick since the second set of cables were installed in 2017.[11] Neither MECL nor its expert, Sargent & Lundy (S&L), has performed any probabilistic analysis of the chance of partial or full disconnection of the import capacity from New Brunswick. However, MECL states that "*the probability of full and partial disconnection events occurring is low*".[12]

a. Explain why it is appropriate to plan for a contingency that has a low probability of occurring.

b. How probable should a contingency be for capacity planning purposes?

c. Does MECL have a probabilistic analysis of the chance of partial or full disconnection of import capacity from New Brunswick. If so, please provide. If MECL does not have one, please complete such an analysis and file it with the Commission or explain why such an analysis cannot reasonably be completed.

Response:

a. Refer to the response to IR-23(a). The proposed project is not justified based on partial or full disconnections from the mainland. This was confirmed by Synapse in their response to IR-3 from Commission Staff.[13]

Similarly, the E3 Study, provided as IR-23 - Attachment 1, did not model partial or full disconnections from the mainland and therefore assumed that the interconnection was always intact. A detailed description of the treatment of the interconnection and imports from New Brunswick ("NB") in the E3 Study is included in Section 4.4 of the study.[14]

b. As discussed in the response to IR-23(a), the need for additional on-Island capacity is not justified based on any individual contingency event.

The E3 Study evaluates system performance across thousands of simulated years, incorporating a wide range of weather conditions, load variability, renewable generation, and forced outages to develop a statistical expectation of system reliability. To determine capacity needs, the study used a LOLE reliability target of 0.1 days per year, which aligns with industry standards and good utility practice. Appendix A of the E3 Study includes a jurisdictional scan of resource adequacy practices across North America, which demonstrates that LOLE reliability target of 0.1 days per year is the most commonly used standard in the industry across North America.

c. The Company has not completed a probabilistic analysis of the chance of partial or full disconnection events from the mainland. Due to the low historical frequency of partial and full disconnection events, the results of such an analysis would not be statistically significant.

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11 Capacity Resource Study, page 14 [Exhibit M-1, Appendix C]; MECL Response to Synapse IR-8 [Exhibit M-6, Appendix A].
12 MECL Response to Synapse IR-10 [Exhibit M-6, Page 17].
13 Exhibit C-26, page 3.
14 IR-23 – Attachment 1 - E3 Study, page 36.

Refer to Maritime Electric's response to IR-8 from Synapse for a comprehensive list of full and partial disconnection events from the mainland, including causes.[15]

[15] Exhibit M-6, page 15.

IR-25 In the 2024 Resource Adequacy Report prepared by New Brunswick Power,[16] the utility states that generation reliability criteria are governed by the loss of load expectation (LOLE) metric. As explained by NB Power, LOLE is a probabilistic calculation of the likelihood of experiencing a loss of load event based on a stochastic analysis of the likelihood that available generation capacity is not sufficient to meet the load demand. The Northeast Power Coordinating Council (NPCC) sets a benchmark of a loss of load expectation of no more than 0.1 days per year.

a. Is the LOLE metric, and the NPCC benchmark of 0.1 days per year, relevant to MECL's application for on-Island capacity?

b. Is yes, explain how. If not, what is the applicable metric and/or probabilistic analysis?

Response:

a. Yes, the LOLE metric, including the NPCC benchmark of 0.1 days per year, is directly relevant to Maritime Electric's application for on-Island capacity.

In Synapse's response to IR-4 from Commission Staff,[17] Synapse argues that "the LOLE metric is not particularly relevant". Maritime Electric disagrees with Synapse's characterization that the relevance of the LOLE metric is limited to the regional capacity position in NB. While the NPCC 2025 Maritimes Area Comprehensive Review is relevant because it confirms tightening regional capacity conditions, the relevance of LOLE to Maritime Electric's December 2024 Application and August 2025 Supplemental Filing re: On-Island Capacity for Security of Supply Project ("Supplemental Filing") for additional capacity resources is broader and more direct.

Maritime Electric's December 2024 Application and Supplemental Filing concern the need for additional firm capacity to maintain reliable service to PEI customers. The E3 Study, provided as IR-23 - Attachment 1, assesses that need using a probabilistic resource adequacy framework and applies the same 0.1 days per year LOLE reliability criterion that is widely used in North American resource adequacy planning, including by NPCC. The LOLE standard is therefore directly relevant because it is the benchmark used to determine whether Maritime Electric's resource portfolio is adequate and to quantify the amount of additional capacity required.

b. Refer to the responses to IR-23(a), IR-24(b), and IR-25(a).

[16] NBEUB Docket EL-002-2025, Renewables Integration and Grid Security (RIGS) Project, Appendix A to the Application [NBEUB Exhibit NBP6.07].
[17] Exhibit C-26, page 4.

IR-26 How many times has New Brunswick Power declared an Energy Emergency Alert since 2004? Explain the circumstances, duration, and impact of each Energy Emergency Alert.

Response:

Table IR-26 provides the number of Energy Emergency Alerts ("EEA") declared by New Brunswick Power Corporation ("NB Power") in each year since 2004 and the respective EEA dates. Detailed information about the EEAs is not readily available.

TABLE IR-26
NB Power Energy Emergency Alert Declarations

Year	Number of EEAs declared	Dates
2004	0	
2005	0	-
2006	0	-
2007	0	-
2008	0	-
2009	0	-
2010	0	-
2011	0	-
2012	2	February 23 and December 1
2013	0	-
2014	0	-
2015	0	-
2016	2	January 5 and December 19
2017	0	-
2018	1	November 13
2019	1	March 27
2020	0	-
2021	0	-
2022	4	January 4, January 11, February 25 and August 6
2023	3	February 3 to 4, June 1 and October 30
2024	0	-
2025	1	December 3
2026	0	-

IR-27 During the polar vortex in February 2023, Quebec curtailed exports to New Brunswick to zero.[18] How often has this happened since 2004?

Response:

Maritime Electric does not maintain records of instances where exports from Hydro-Québec ("HQ") to NB were reduced to zero or near zero.

The Company consulted with representatives of NB Power regarding this question. Based on information readily available to NB Power, the February 2023 event is the only specific instance identified where HQ significantly reduced exports to NB due to internal capacity constraints. The Company is not aware of any record identifying the number of similar events that may have occurred since 2004.

While the history of such events is not known with certainty, the evidence filed by NB Power in its Renewables Integration Grid Security ("RIGS") Project proceeding indicates that HQ's ability to provide dependable winter exports is expected to decline. The RIGS Plants Assessment Report prepared by The Brattle Group states that HQ is forecasting future capacity deficits, faces rising domestic demand, and must prioritize domestic reliability and existing export commitments during periods of extreme winter demand.[19] The report further notes that during the February 2023 cold weather event, HQ effectively reduced exports to NB, from approximately 1,000 MW to near zero, during a period when NB was also experiencing high demand and supply challenges.

In its responses to interrogatories from Dr. Andrew G. Secord as part of the RIGS Project, NB Power also stated the following:[20]

> *The product supplied by Hydro-Quebec to NB Power is not capacity backed energy, which by definition must be delivered when required. Hydro Quebec does not have excess capacity during the coldest winter months and therefore does not offer a capacity backed product to NB Power. As a result, the firm energy product supplied by Hydro-Quebec to NB Power may be curtailed in favour of Hydro Quebec's in-province customers. NB Power must therefore be prepared to have firm energy curtailed from Hydro Quebec on the coldest winter mornings or when HQ may be in a capacity deficiency due to significant unplanned generation outages on the HQ system.*

Accordingly, regardless of the historical frequency of such events, the evidence available to the Company indicates that HQ cannot be relied upon as a dependable source of firm winter capacity during periods of coincident regional system stress.

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[18] Addendum to the Capacity Resource Study, page 15 [Exhibit M-1, Appendix D].

[19] NB Energy & Utilities Board docket number EL-002-2025 (RIGS), Exhibit NBP6.16 – Appendix F – RIGS Plants Assessment Report (Prepared by The Brattle Group), pp. 45-48, 52, and 57.

[20] NB Energy & Utilities Board docket number EL-002-2025 (RIGS), Exhibit NBP8.74 NBP Responses to Interrogatories of Dr. Andrew G. Secord (Dr. Andrew G. Secord) REDACTED.pdf, response to IR-74, page 3.

IR-28 Over the last several years, Prince Edward Island has experienced a number of extreme weather events, including polar vortexes in February 2023 and January 2026.

a. Was MECL's connection to the mainland disconnected (partially or fully) during these events?

b. Was MECL required to shed load or implement rolling blackouts due to a lack capacity from the mainland during these events?

c. Was MECL required to operate existing on-Island generation to serve its customers during these events?

i. If yes, for how long and at what cost?
ii. Was MECL's existing on-Island capacity sufficient to provide uninterrupted service to its customers?

Response:

a. No, Maritime Electric's connection to the mainland was not disconnected during the February 2023 and January 2026 weather events referenced. Refer to Maritime Electric's response to IR-8 from Synapse for a comprehensive list of full and partial disconnection events from the mainland, including causes.[21]

b. No, Maritime Electric was not required to shed load or implement rotating outages due to a lack of capacity from the mainland during these events.

c. Yes. Maritime Electric operated its on-Island dispatchable generation extensively during both of these events.

i. Details related to the operation of existing on-Island generation during the cold weather events in February 2023 and January 2026 are shown in Table IR-28.

[21] Exhibit M-6, page 15.

TABLE IR-28 Combustion Turbine Operating Data During Cold Weather Events			
	CT1	**CT2**	**CT3**
February 3 to 5, 2023, polar vortex			
Operating hours (hours)	41	41	52
Energy generated (megawatt-hour ("MWh"))	291	441	1,407
Estimated energy cost rate ($/MWh)[22]	809	855	454
Estimated cost ($ x 1,000)	235	377	639
January 24 to 26, 2026, cold weather event			
Operating hours (hours)	-	11	59
Energy generated (MWh)	-	97	1,273
Estimated energy cost rate ($/MWh)	809	855	454
Approximate Cost ($ x 1,000)	-	83	578

ii. Yes. Refer to the response to IR-28(b).

[22] $454/MWh for CT3 is an annual average based on the total CT3 fuel consumption and generation in 2025. $809/MWh and $855 for CT1 and CT2, respectively, are based on a cost of $454/MWh for CT3 scaled based on respective heat rates shown in Exhibit M-1, Table 24 (page 120).

IR-29 Explain the relationship between increased Hold-to-Schedule events and on-Island renewable energy supplies.[23]

Response:

Refer to Section 7.3 of the December 2024 Application,[24] which describes the relationship between hold-to-schedule events and on-Island renewable generation.

Renewable generation is scheduled in advance; however, due to the energy production variability of wind and solar resources, actual production may differ from forecast production. When renewable energy production is lower than forecast, Maritime Electric initially seeks to increase imports to make up for the shortfall. However, if the NB system is constrained and cannot supply the additional energy required, the NB Transmission System Operator ("NBTSO") may issue a hold-to-schedule directive, requiring Maritime Electric to maintain its scheduled import level.[25] In these circumstances, the energy shortfall must be met through on-Island dispatchable generation or, absent sufficient on-Island supply, reduced customer load (i.e., load shedding).

As on-Island renewable energy production increases as a component of Maritime Electric's energy supply mix, the magnitude and frequency of hold-to-schedule events is expected to increase. This will result in greater reliance on on-Island dispatchable generation resources (or, in the future, energy storage) to backstop renewable energy production variability.

[23] Application, page 117, lines 13-14 [Exhibit M-1].
[24] Exhibit M-1, page 86.
[25] A hold-to-schedule event does not necessarily reflect a physical transmission constraint and may result from transmission service being fully reserved by other market participants following a forecast of high renewable production and reduced import requirements from Maritime Electric.

Capacity Needs

IR-30 MECL completes a capacity resource adequacy assessment (CRAA) annually.[26] Provide MECL's CRAA from 2015 to the most recent CRAA available.

Response:

Maritime Electric's 2015 to 2026 capacity resource adequacy assessments ("CRAA") are provided in IR-30 - Attachment 1.

[26] Application, page 44, lines 11-13 [Exhibit M-1].

IR-31 In the Capacity Resource Study, S&L initially recommended a minimum of 85 MW of additional on-Island capacity. However, following the polar vortex in February 2023, S&L recommended that on-Island capacity be increased to 125 to 150 MW.[27] According to MECL, "*Polar vortexes are uncommon and resulted in an abnormally high system peak due to the extreme cold*".[28]

a. Explain why MECL is relying on an abnormally high system peak caused by an uncommon event for capacity planning purposes.

b. Is this consistent with industry standards and good utility practice?

Response:

The increase in the Capacity Resource Study recommendation from 85 MW to 125-to-150 MW following the February 2023 polar vortex reflected updated information regarding how winter peak demand was developing on the PEI system and the increasing reliability risks associated with reliance on off-Island resources. As previously explained, the February 2023 event highlighted several emerging trends, including the increased temperature sensitivity of the load due to the electrification of space heating and the resulting shift in peak demand from a predominantly December peak to one that is increasingly driven by cold temperatures in either December, January or February.[29]

This shift has resulted in closer alignment between PEI and NB winter peak periods. Historically, this difference in peak timing created a capacity synergy, whereby surplus capacity was often available from NB during PEI peak periods. However, as PEI peak demand has become more closely aligned with regional peak demand periods, the availability of surplus capacity from neighbouring jurisdictions has diminished. In addition, NB Power had already begun signaling concerns regarding the diminishing availability of surplus generating capacity within the region. The February 2023 polar vortex reinforced these concerns by demonstrating that neighbouring systems were operating under stressed conditions during the same periods that PEI required support.

a. The assumption that Maritime Electric is relying on "an abnormally high system peak caused by an uncommon event" for capacity planning purposes is incorrect.

Maritime Electric does not rely on the February 2023 polar vortex peak as its capacity planning criterion. Refer to the December 2024 Application,[30] which states the following:

> *The 2023 system peak [i.e., 359 MW] occurred during the February 2023 polar vortex weather event. Polar vortexes are uncommon and resulted in an abnormally high system peak due to the extreme cold. Maritime*

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27 Addendum to the Capacity Resource Study [Exhibit M-1, Appendix D].

28 Application, page 39, footnote 56 [Exhibit M-1].

29 As discussed in the December 2024 Application, the increase in system peak demand is largely driven by increased electrification of space heating, which makes the system increasingly sensitive to cold weather conditions. Maritime Electric's April 24, 2025, capacity update letter to IRAC (Exhibit M-3), further notes that peak demand is increasingly driven by electric heating load and that the system's heating coefficient has increased significantly, indicating greater sensitivity to colder weather.

30 Application, page 39, footnote 56 [Exhibit M-1].

Electric's 2024 system peak forecast [i.e., 310 MW] is based on normal winter conditions.

Maritime Electric's peak forecast for capacity planning purposes is calculated using historical average temperatures to reduce volatility in the forecast from extreme peaks in any given year. Section 5.3.1 of the December 2024 Application states that the forecast for residential space heating is based on an ambient temperature of minus 13.6°C, which is the average temperature at which the system peak occurred during the previous ten years. Accordingly, the load forecast underlying the December 2024 Application was based on normal winter conditions rather than the approximately minus 27°C temperatures experienced during the February 2023 polar vortex.

Maritime Electric notes that this approach is consistent with Synapse's response to Commission Staff IR-5, which acknowledged that the Company's capacity requirements forecast is based on a 50/50 peak demand forecast[31] and reserve margin, and not the February 2023 polar vortex peak.

Similarly, the E3 Study, provided as IR-23 - Attachment 1, uses Maritime Electric's "median peak load forecast in 2030" as the source for the 2030 peak load used as part of the modelling for the study.[32] The median peak load is representative of normal winter conditions, whereas there is an expected 50 per cent chance that the actual peak will be higher (or lower) than the peak forecast.

b. Maritime Electric's existing practice and the modelling approach used in the E3 Study, which consist of using the median peak forecast for capacity planning purposes, is consistent with industry standards and good utility practice.

[31] A "50/50 peak demand forecast" is a forecast such that there is an expected 50 per cent chance that the actual peak will be higher (or lower) than the peak forecast.

[32] IR-23 – Attachment 1 - E3 Study, Section 4.1, page 31.

IR-32 Historically, Maritime Electric has not used the percentage of peak load to determine the amount of generating capacity that should be installed on-Island.[33] Rather, the availability of surplus generating capacity on the mainland and the import capacity of the Interconnection determined the amount of generating capacity required on-Island.

a. Explain why MECL has changed the metric for determining on-Island capacity needs.

b. Explain why the ratio of capacity to peak load is relevant to capacity planning.

c. Explain why 50 percent of MECL's capacity requirements must be on-Island.

d. Assume MECL continues to use available surplus generating capacity and import capacity to determine on-Island capacity needs. Using this metric, is additional on-Island capacity required at this time? Please explain and provide supporting calculations and assumptions.

Response:

a. Refer to Maritime Electric's response to IR-7 from Synapse on behalf of the Commission.[34]

The Company explained that historically, more than 50 per cent of its capacity resources were located on PEI, and that 2022 marked the first time that this percentage was below 50 per cent. As a result, the 50 per cent metric is a new planning consideration.

b. Refer to Maritime Electric's response to IR-7 from Synapse,[35] which explains that the 50 per cent target is a planning objective aimed at maintaining a balanced approach to capacity supply. It reflects the Company's historical operating experience, as well as the recognition that as the relative percentage of on-Island capacity declines, the system becomes increasingly reliant on imported capacity, which limits operational flexibility and increases dependence on external resources.

The 50 per cent target also reflects that operating the system at elevated loads without on-Island generation places increased stress on the system, reducing its ability to maintain reliable operation during disturbances. The planned minimum level of on-Island generation helps to assure system stability and enhances the system's ability to respond to and withstand contingency events. In addition, this planning approach recognizes that while off-Island capacity is beneficial, it exposes the Company to market-based price volatility and availability risk. In contrast, on-Island generation provides a stable and predictable source of capacity over the life of the asset, with costs established at the time of development and largely unaffected by external market pressures.

c. Refer to the response to IR-32(a) and IR-32(b).

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33 MECL Response to Synapse IR-6 [Exhibit M-6].
34 Exhibit M-6, page 12.
35 Exhibit M-6, page 12.

d. Maritime Electric continues to utilize available surplus generating capacity and import capability from NB as part of its capacity resource mix.

Table IR-47, included in the response to IR-47, illustrates the Company's capacity requirements, available capacity resources, and resulting capacity deficit over the planning horizon. This analysis assumes that Maritime Electric procures all available off-Island capacity resources. However, even under this assumption, the Company remains unable to meet its capacity requirements, demonstrating that additional on-Island capacity is required to maintain reliable service.

IR-33 Historically, MECL has used the single highest system peak load (1CP) to allocate costs in its Cost Allocation Studies. However, in its most recent 2023 Cost Allocation Study, MECL used 3CP to minimize volatility associated with the extreme weather conditions during the February 2023 polar vortex.[36]

a. Explain why MECL has averaged the system peak to minimize volatility in its most recent Cost Allocation Study, but relies on the single highest peak for capacity planning purposes.

b. Is this consistent with industry standards and good utility practice?

Response:

a. Maritime Electric does not rely on the single highest peak (1CP) for capacity planning purposes.

As described in the response to IR-31(a), Maritime Electric's peak forecast for capacity planning purposes is based on normal winter conditions rather than any individual peak event.

1CP and 3CP metrics are based on coincident peaks experienced in a single study year. For example, the 3CP metric calculated in the 2023 Cost Allocation Study is based on the three highest coincident peaks experienced in 2023. Conversely, Maritime Electric's peak forecast for capacity planning purposes is calculated using historical average temperatures over several years to reduce volatility in the forecast from extreme peaks in any given year.

b. Refer to the response to IR-31(b).

[36] Commission Docket UE22503 (Rate Design), specifically Exhibit M-13.

IR-34 MECL states that it has recently conducted a thorough review of its system and has determined that during a disconnection the system is not strong enough to support any wind generation.[37]

a. Provide a copy of this review.

b. What is meant by MECL's "system"?

c. Why is the system not strong enough to support any wind generation during a disconnection from the mainland?

Response:

a. Maritime Electric has not prepared a standalone review document; rather, the review occurred during consideration of an external supplier proposal to study what system modifications would be necessary to support renewable generation when islanded.[38] The referenced determination resulted from internal discussions among engineering staff, which concluded that with the dispatchable generation currently on-Island, the ability to support renewable energy production when islanded is significantly limited. The Company will revisit this assessment once plans for additional capacity resources have been finalized.

b. In this context, Maritime Electric's system refers to its on-Island electrical system, including the combustion turbines ("CTs") at the Borden-Carleton Generating Station, the CT at the Charlottetown Generating Station, and the transmission network owned and operated by Maritime Electric.

c. Refer to the December 2024 Application page 84,[39] which states the following:

> *During a disconnection, the Company's existing CTs could adequately respond to normal renewable energy generation increases and decreases resulting from small changes in wind speed or cloud cover; however, the decreased system stability (i.e., system strength) when disconnected from the mainland means that system disturbances, such as faults or generator trips, would result in critical system instabilities, such as voltage drops or frequency deviations.*

While it is theoretically possible to support online wind generation during a disconnection event, doing so would exacerbate system stability concerns. In contrast, the addition of two 50 MW CTs would improve system stability by increasing the number of generators supporting the grid and reducing the impact of any single generator trip.

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37 Application, page 95, footnote 150 [Exhibit M-1].

38 "Islanded" refers to operation of the PEI electrical system in isolation from the NB electrical system, such that customer load is supplied solely by on-Island generation resources following a full disconnection from the mainland.

39 Exhibit M-1, page 84.

Load Forecast

IR-35 Government incentive programs have been a significant factor in growing electrification in Prince Edward Island, specifically for residential space heating. As of 2026, many of the provincial government incentive programs are no longer being offered. What impact does this have on MECL's load forecast?

Response:

The pause of provincial Government incentive programs caused a reduction in Maritime Electric's energy sales and peak demand forecasts, which is reflected in the February 2026 load forecast provided in the response to IR-37.

Recently, on June 29, 2026, the Government of Canada announced an expansion of the Canada Greener Homes Affordability Program, which includes funding for free heat pumps available to PEI residents.[40] Maritime Electric is still evaluating the impact of the Canada Greener Homes Affordability Program announcement and will include these in the next iteration of the load forecast.

[40] https://natural-resources.canada.ca/energy-efficiency/home-energy-efficiency/canada-greener-homes-initiative/canada-greener-homes-affordability-program#a1a

IR-36 In 2024, MECL received approval for its Advance Metering for Sustainable Electrification Project (Docket UE20737). The new customer information system and advanced metering infrastructure, once operational, will allow for time-of-use (TOU) rates. TOU rates can be used to effectively shift electricity usage and reduce peak demand.[41]

a. When will the CIS and AMI be operational?

b. Assume TOU rates are approved by the Commission as of the date that the CIS and AMI are operational. Provide the forecast reduction in MECL's peak demand resulting from TOU rates.

Response:

a. The installation of advanced metering infrastructure ("AMI") meters is expected to be completed by the third quarter of 2027. The new customer information system ("CIS") is expected to be fully commissioned and operational by the end of 2027.

b. Refer to Maritime Electric's response to IR-16(b) from Synapse.[42]

Peak reduction achievable in the first year would depend on customer uptake.

It is also important to note that an ELCC analysis is required to determine the amount of perfect capacity accredited to all resources, including demand response and time-of-use ("TOU") rate programs and,[43] similar to demand response programs, TOU rates contribute to critical periods in ways similar to energy storage, which impacts ELCC results.[44] The E3 Study, provided as IR-23 - Attachment 1, states:

> *Energy storage and demand response resources contribute to the system in similar ways and tackle the same types of critical periods – shorter in duration but higher in magnitude. This must be taken into consideration when evaluating a combination of ELR [energy limited resource] additions, as the combined ELCC can be lower than what standalone ELCCs added together would yield.*

41 Exhibit M-24.
42 Exhibit M-6, page 28.
43 IR-23 – Attachment 1 - E3 Study, Section 5.3 - pages 48-49.
44 IR-23 – Attachment 1 - E3 Study, footnote 2 (page 9) for an explanation of perfect capacity.

IR-37 Provide MECL's updated (2026) load forecast.[45]

Response:

Maritime Electric's updated load forecast, completed in February 2026, is provided in Table IR-37.

TABLE IR-37
Updated Maritime Electric Load Forecast (February 2026)

Year	December 2024 Application	Updated February 2026 Load Forecast	
	Peak Demand (MW)	Peak Demand (MW)	Energy Sales (GWh)
2025A	350 (forecast)	346	1,581
2026F	363	362	1,626
2027F	373	372	1,644
2028F	383	379	1,669
2029F	393	386	1,692
2030F	402	393	1,714
2031F	411	399	1,734
2032F	420	405	1,755
2033F	429	411	1,775
2034F	-	417	1,796
2035F	-	424	1,816

[45] MECL Response to PEIEC IR-7 [Exhibit M-21].

NB-PEI Interconnection

IR-38 MECL refers to the "NB-PEI Interconnection" throughout its Application, but does not define the assets and equipment that are included in the interconnection. Please define.

Response:

The Company uses the term "NB–PEI Interconnection" as an overarching description of the infrastructure connecting the PEI electrical system to the NB electrical system.

The NB-PEI Interconnection includes all equipment and facilities between the 138 kV buses at Borden-Carleton and Bedeque substations in PEI, and the 138 kV bus at Memramcook substation in NB, including, but not limited to, transmission lines, subsea cables, terminal equipment, breakers, protection systems, and associated control and communication systems.

IR-39 Provide the most recent copy of the Interconnection Agreement between MECL and NB Power.

Response:

The most recent Interconnection Agreement between Maritime Electric and NB Power is provided as IR-39 - Confidential Attachment 1.

Alternatives to On-Island Capacity

IR-40 In the Capacity Resource Study, S&L assumes that additional on-Island capacity is required, without consideration of other alternatives, such as improvements to the New Brunswick transmission system and Interconnection, and/or the purchase of additional off-Island capacity.

a. Explain why S&L did not consider off-Island capacity solutions.

Response:

a. The Capacity Resource Study ("CRS") prepared by Sargent & Lundy LLC ("S&L") considered Maritime Electric's existing supply mix, including off-Island capacity resources, and identified the need for additional firm capacity to maintain reliable service. The study emphasized the importance of increasing the proportion of on-Island capacity resources, recognizing the risks associated with a high reliance on imported capacity, including exposure to regional capacity shortages and the potential for curtailment or disconnection events.

In this context, the CRS was performed on the basis that existing off-Island capacity arrangements would continue to be available, but did not assume that additional off-Island capacity beyond those arrangements would be available. As discussed in the response to IR-46(a), the amount of capacity available for purchase from off-Island resources is a constraining factor in meeting future requirements. Accordingly, the CRS focused on identifying the additional firm capacity required to ensure reliability under expected system conditions, rather than relying on future capacity resources whose availability was uncertain and outside the Company's control.

IR-41 Historically, purchasing generating capacity from NB Power resulted in cost savings for Maritime Electric customers because off-Island capacity was more economical than building new on-Island capacity resources.[46]

a. Is adding new on-Island generating capacity the least cost option to address MECL's forecast capacity deficit? Provide all supporting calculations and assumptions.

Response:

a. Refer to the responses to IR-48(a) and IR-49(a).

[46] MECL Response to Synapse IR-4 [Exhibit M-6].

IR-42 Throughout its Application, MECL makes reference to limitations with the New Brunswick transmission system that constrain capacity transfers to PEI. Improvements to the New Brunswick transmission system are imminent, and MECL expects to contribute financially to these improvements.

a. Provide full particulars of the anticipated improvements to the New Brunswick transmission system. Include supporting documentation from New Brunswick Power.

b. What additional improvements to the New Brunswick transmission system are planned for the next 5 to 10 years?

c. What impact will these improvements have on both reliability and transmission capacity to PEI?

Response:

a. The anticipated improvements to the transmission system in NB that may affect PEI are as follows:

- Saint John Corridor Project;[47]
- Renewables Integration Grid Security (RIGS) Project;[48]
- Salisbury Static Synchronous Compensator (STATCOM) Project;[49] and
- NB/NS Interprovincial Transmission Line Project Phase 1 and 2.[50]

b. All of the projects listed above, with the exception of Phase 2 of the NB/NS Interprovincial Transmission Line Project, are generally expected to be completed within the next five years. Phase 2 of the NB/NS Interprovincial Transmission Line Project is being considered within a 5- to 10-year timeframe; however, both the timing and likelihood of this project proceeding remain uncertain.

c. Collectively, these projects are expected to enhance the reliability of, and may increase the transmission capacity of, the NB Power transmission system serving PEI. The extent of any capacity increases has not yet been quantified.[51] To increase firm transmission capacity to PEI, upgrades to the NB-PEI Interconnection would also be required.

47 https://www.nbpower.com/en/about-us/projects/saint-john-corridor-project/
48 https://www.nbpower.com/en/about-us/projects/renewables-integration-grid-security-rigs-project
49 https://www.nbpower.com/en/about-us/projects/static-synchronous-compensator-statcom/
50 https://www.nbpower.com/en/about-us/projects/new-brunswick-nova-scotia-interprovincial-transmission-line-project
51 Such capacity increases cannot be calculated by Maritime Electric; they must be calculated by NBTSO and shared with Maritime Electric.

IR-43 MECL states that additional on-Island capacity is needed due to transmission constraints in New Brunswick and concerns about potential generating shortages in Atlantic Canada.[52]

At the time that MECL filed its Application in December 2024, NB Power expected to be capacity deficient within 5 years if new capacity was not added.[53] Since the Application was filed, new capacity has been planned for the region, including in New Brunswick and Nova Scotia.

a. Provide particulars of all new capacity that has been added or planned for the Maritime region since the Application was filed in December 2024.

b. Is NB Power still expected to be capacity deficient within 5 years? Providing supporting documents from NB Power.

c. What is the current forecast capacity surplus (or deficit) for the Maritime region?

d. Explain whether the new generation capacity that has been added or planned in the Maritime region since December 2024 changes MECL's assessment of the need, timing, or amount of additional on-Island capacity proposed in this Application. If not, explain why not.

e. Since the Application was filed, additional wind generation projects have been announced, approved or placed into service in Prince Edward Island. Explain whether the increase in on-Island wind generation changes MECL's assessment of the need, timing, or amount of additional on-Island capacity proposed in this supplemental application. If not, explain why not.

f. Since the Application was filed, the Province of Prince Edward Island has announced plans to develop a utility-scale battery energy storage system. Explain whether this project changes MECL's assessment of the need, timing, or amount of additional on-Island capacity proposed in this Application. If not, explain why not.

Response:

a. Since filing the December 2024 Application, several new dispatchable generation and storage projects in Atlantic Canada have been announced, approved or added, as described below.

New Brunswick

NB Power announced the RIGS Project in July 2025 and subsequently selected ProEnergy as the development partner for a new dispatchable generation facility, consisting of dual-fuel CTs and synchronous condensers. The RIGS Project has evolved to include approximately 500 MW of capacity, with 400 MW intended to meet NB Power's

[52] Application, page 5, lines 23-26 [Exhibit M-1].
[53] Application, page 20, lines 8-9 [Exhibit M-1].

system needs, and the final 100 MW intended to serve Nova Scotia ("NS") initially. The project is expected to be online in 2028.[54]

NB Power has also issued a Request for Expressions of Interest ("REOI") for a BESS totaling 50 MW with approximately four hours of storage duration. NB Power has stated that the project is intended to provide system flexibility and support the integration of renewable resources while contributing to long-term energy security.[55]

Nova Scotia

The Independent Energy System Operator of Nova Scotia ("IESONS") has initiated a competitive procurement process for up to 600 MW of new fast-acting generation capacity (i.e., CTs). The procurement specifically contemplates one or two approximately 300 MW natural gas-fired generating facilities capable of providing fast-start generation and grid support services. According to IESONS, the procurement is intended to address growing demand, support renewable integration, facilitate the phase-out of coal-fired generation, and maintain system reliability.[56]

NS has also been advancing utility-scale BESS projects as part of its reliability strategy. IESONS's 2026 10-Year System Outlook reports that 100 MW of BESS was added to NS's resource mix in 2025. Maritime Electric understands this to be part of a project to develop three (3) 50 MW 4-hour BESSs in the province.[57]

Prince Edward Island

The PEI Energy Corporation ("PEIEC") issued a REOI in March 2026 for a utility-scale BESS ranging from 10 MW to 50 MW with 4-hour duration and an option to extend it to 8-hour. According to the REOI, the project is intended to provide capacity and other grid support services to the PEI electrical system.

Newfoundland and Labrador

Although IR-43(a) refers specifically to the Maritime region, Maritime Electric believes it is appropriate to also identify major dispatchable capacity developments in Newfoundland and Labrador, given the interconnected nature of Atlantic Canadian resource adequacy planning and the relevance of these projects to regional capacity requirements.

Newfoundland and Labrador Hydro ("NL Hydro") is advancing the Avalon Combustion Turbine Project, which consists of a new 150 MW combustion turbine ("CT") facility in Holyrood, NL. NL Hydro has stated that the project was identified through its resource adequacy planning process as a least-cost option to provide peaking and standby generation, improve system reliability, and support the eventual retirement of existing

54 https://www.nbpower.com/en/about-us/projects/renewables-integration-grid-security-rigs-project
55 https://www.nbpower.com/en/about-us/news-media-centre/news/2025/nb-power-invites-expressions-of-interest-for-15-year-battery-storage-partnership/
56 https://ieso-ns.ca/ieso-nova-scotia-opens-competitive-procurement-process-for-critical-electricity-generation-capacity-to-replace-coal-fired-power-plants/
57 https://www.nspower.ca/docs/default-source/monthly-reports/10-year-system-outlook-report.pdf?sfvrsn=d39bca29_68

thermal generating units. The project is currently undergoing regulatory review and is planned for completion in 2030.[58]

NL Hydro has also applied to construct Bay d'Espoir Unit 8, an additional 150 MW hydroelectric generating unit at the existing Bay d'Espoir generating station. NL Hydro has identified Bay d'Espoir Unit 8 and the Avalon Combustion Turbine Project as the minimum investments required to address forecast capacity needs and maintain system reliability.[59]

Maritime Electric notes that several of the projects identified herein remain under development, procurement, or regulatory review and are not yet in service. In addition, the projects are being developed to meet the reliability and resource adequacy needs of their respective jurisdictions and do not necessarily increase the firm capacity contractually available to other provinces.

b. Yes. As part of the RIGS Project, NB Power filed a resource adequacy assessment dated March 18, 2024, which is provided as IR-43(b) - Attachment 1. In that assessment, NB Power concluded that its planning reserve margin criteria identified a capacity shortfall that would grow to approximately 200 MW by 2028 and that its operational reserve criteria identified a capacity shortfall exceeding 400 MW by 2028. NB Power further concluded that additional risk factors could increase these deficiencies and recommended that NB Power immediately begin the process of acquiring 400 MW of generation capacity by 2028.

Since that assessment was completed, the RIGS Project has been approved and is expected to provide NB Power with approximately 400 MW of additional capacity beginning in 2028.[60] The approval of the RIGS Project therefore addresses the specific capacity requirement identified in the March 2024 resource adequacy assessment for the 2028 timeframe.[61] However, the same resource adequacy assessment also indicates that beyond the 2028 timeframe addressed by the RIGS Project, additional capacity will be required. Specifically, NB Power recommended that planning begin in 2024/25 for a further 600 MW of capacity that could be needed as early as 2030, reflecting forecast capacity deficiencies that re-emerge following the addition of the RIGS Project resources due to load growth.

Accordingly, while the RIGS Project is expected to address near-term capacity requirements, NB Power's most recent resource adequacy assessment indicates that additional resource development may be required as early as 2030, and that regional capacity constraints are expected to persist.

c. The current capacity forecast for the Maritime region is presented in the NPCC 2025 Maritime Area Comprehensive Review of Resource Adequacy, which was previously submitted to the Prince Edward Island and Regulatory and Appeals Commission (the "Commission") as Exhibit C-26b by Synapse.

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58 https://nlhydro.com/wp-content/uploads/2025/05/P.U.-172025_NLH_Early-Works-Application.pdf
59 https://nlhydro.com/wp-content/uploads/2025/05/P.U.-172025_NLH_Early-Works-Application.pdf
60 The final 100 MW associated with the 500 MW plant has been committed to NS initially.
61 The March 2024 Resource Adequacy Assessment for NB Power is included as IR-43(b) - Attachment 1.

The NPCC 2025 Maritime Area Comprehensive Review of Resource Adequacy indicates that the Maritime Area exceeds the 0.1 day per year LOLE criterion in 2026 and 2027, but is forecast to satisfy the criterion beginning in 2028. The improvement beginning in 2028 reflects the addition of planned generation and capacity resources included in the NPCC assessment.

d. No. The projects identified in the response to IR-43(a) do not change Maritime Electric's assessment of the need, timing, or amount of additional on-Island capacity proposed in the December 2024 Application. These projects are being developed to satisfy the resource adequacy requirements of the jurisdictions constructing them. As demonstrated by both the NB Power Resource Adequacy Report and the NPCC Maritime Area Resource Adequacy Review, these resources are required to meet forecast provincial reliability needs and are not expected to create significant long-term surplus capacity available for export to PEI.

Even if some surplus capacity from these projects became temporarily available, Maritime Electric does not consider such capacity a viable long-term solution. The utilities developing these projects are experiencing load growth and would reasonably be expected to utilize those resources to serve their own customers as requirements increase.

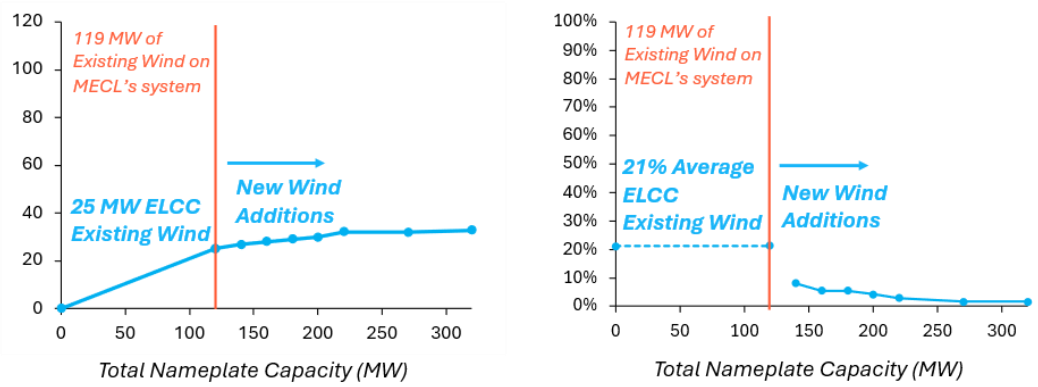
Furthermore, additional off-Island capacity is not expected to be a lower-cost solution. Utilities must recover the full cost of new generation investments and would not be expected to sell capacity to PEI at less than the cost of developing, financing, operating, and maintaining those resources. Accordingly, Maritime Electric continues to conclude that additional on-Island dispatchable capacity remains necessary and is the least-cost solution.

e. No. The increase in on-Island wind generation since the December 2024 Application was filed does not change Maritime Electric's assessment of the need, timing, or amount of additional on-Island capacity proposed.

Since the December 2024 Application was filed, the approximately 30 MW Eastern Kings Phase 2 wind project was commissioned. The Company's analysis indicates that the incremental ELCC of the Eastern Kings Phase 2 wind farm is approximately 3 MW. Following that addition, the Company’s total ELCC of all contracted wind resources is 25 MW, as shown in Figure IR-43, taken from the E3 Study.[62] Figure IR-43 also illustrates that the marginal ELCC of additional wind resources declines as wind penetration increases, with incremental wind additions in PEI contributing only a small fraction of their nameplate capacity to resource adequacy.

[62] IR-23 – Attachment 1 - E3 Study, Section 5.3.1, page 46.

FIGURE IR-43



This occurs because once a significant amount of wind capacity has been installed, reliability risk shifts away from periods when wind generation is available toward periods of high demand when wind output is low. As a result, additional wind projects provide diminishing reliability benefits and do not materially change the need, timing, or amount of dispatchable capacity proposed in the December 2024 Application.

f. No. Even if PEIEC were to proceed with the largest battery project contemplated in its REOI, which is a 50 MW 8-hour BESS, the proposed 100 MW Accelerated Capacity Solution would still be required. The BESS would reduce the remaining capacity deficiency but would not change the need, timing, or amount of additional on-Island capacity proposed in the December 2024 Application.

The PEIEC initiative is currently at the REOI review stage. As such, the final size, duration, configuration, ownership structure, commercial arrangements, and in-service date of any BESS project remain uncertain. Accordingly, the project cannot currently be relied upon as a committed capacity resource for planning purposes.

Notwithstanding this uncertainty, Maritime Electric evaluated BESS as part of the E3 Study, provided as IR-23 - Attachment 1, which concluded that BESS could provide meaningful capacity value on the PEI system and can reduce the amount of additional capacity required to satisfy resource adequacy requirements. However, the E3 Study also demonstrated that BESS alone cannot fully satisfy Maritime Electric's reliability requirements on a cost-effective basis. The E3 Study specifically identified portfolios that combined the proposed Accelerated Capacity Solution with BESS resources. The E3 Study found that approximately 85 MW of 4-hour energy storage or approximately 50 MW of 8-hour energy storage, would be required in combination with the proposed Accelerated Capacity Solution to satisfy the reliability requirement (Portfolio 3 and Portfolio 8, respectively).[63]

[63] IR-23 – Attachment 1 - E3 Study, Section 5.3.6, page 52.

IR-44 In 2015, Maritime Electric sought Commission approval to purchase and install a 50 MW combustion turbine.[64] The application was withdrawn to allow MECL to focus on expanding the New Brunswick-PEI Interconnection.[65] Today, the NB-PEI Interconnection remains a limiting factor in transmission capacity to PEI. Although the physical capacity of the four subsea cables is 560 MW, the Interconnection capacity is limited to 300 MW.

a. MECL states that, as of December 2024, it was studying the expansion of the Interconnection.[66] Provide a copy of this study.

b. Is improving the NB-PEI Interconnection to increase transmission capacity above 300 MW an alternative to on-Island generation?

c. What steps has MECL taken to expand the NB-PEI Interconnection prior to filing this Application in December 2024, and since?

Response:

In the 2015 application, the need for the 50 MW CT was based on the ability of the NB transmission system to deliver firm capacity to PEI being limited to 80 MW. In the second half of 2015, NB Power increased the amount of firm transmission capacity that could be delivered to PEI, based on an updated analysis. Given this increase in firm transmission capacity, and opposition to the project from the PEI Government, Maritime Electric withdrew its application.

a. A copy of the study is provided as IR-44 - Attachment 1.

b. Increasing the capacity of the NB-PEI Interconnection will increase transmission capacity, whereas the Accelerated Capacity Solution increases firm generating capacity. Refer to the response to IR-46(a), which explains that sufficient off-Island generating capacity is not available.

c. Maritime Electric has engaged with both NB Power and New Brunswick Energy Marketing ("NBEM") to seek additional interconnection transmission capacity since filing the December 2024 Application. Referring to Exhibit M-24, page 3, footnote 7, which states the following:

> *NB Power is currently studying ways to increase this import limit to 350 MW after the installation of NB Power's combustion turbine project in Centre Village, and would require the implementation of automatic load shedding measures if a cable were to trip.*

As part of these efforts, NB Power recently identified an incremental 40 MW of non-firm transmission capacity for PEI, which is expected to be available by the winter of 2026/27, before NB Power's CT project in Centre Village is completed.

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64 Commission Docket UE20723.
65 Application, page 17, footnote 16 [Exhibit M-1].
66 Application, page 112, footnote 178 [Exhibit M-1]; MECL Response to PEIEC IR-14 [Exhibit M-21].

Considering this development, the NB-PEI Interconnection is currently being assessed by the system operators in PEI and NB to determine whether transfers of up to 340 MW can be accommodated. Preliminary results indicate that this increase in non-firm transmission capacity may be achievable, provided that automatic load shedding schemes are implemented. These schemes would rapidly disconnect load during transmission contingency events to preserve system integrity, particularly with respect to Cables 1 and 2.

Any such automatic load shedding schemes and reliance on non-firm transmission should be considered temporary, until the necessary NB-PEI Interconnection and NB transmission system upgrades are completed. Both are needed to ensure that increased firm transmission can be provided by NB Power. However, increased transmission capability alone does not create additional generating capacity. The ability to import additional electricity during periods of high demand depends on both transmission capability and the availability of generating capacity resources in neighbouring jurisdictions.

IR-45 MECL discusses the pending replacement of Cables 1 and 2, noting that once they reach end of life, they will likely be replaced with cables having a capacity of 180 MW, similar to Cables 3 and 4. The replacement of Cables 1 and 2, together with a fourth transmission line connecting the mainland system to the Cables, will increase the transfer capacity of the Interconnection.[67]

a. Provide particulars of any and all discussions with Government (at any level) about the replacement of Cables 1 and 2.

b. When are Cables 1 and 2 expected to be replaced?

c. Who will pay for the cost of replacing Cables 1 and 2?

d. Assume that Cables 1 and 2 are replaced with 180 MW cables, a fourth transmission line is constructed, and the New Brunswick transmission system upgrades are completed. In this scenario, is additional on-Island capacity required? Explain with supporting evidence and assumptions.

Response:

a. Maritime Electric, through interactions with PEIEC and its participation on the Interconnection Committee, regularly discusses the replacement of Cables 1 and 2.

In September 2023, Maritime Electric advised the former Department of Environment, Energy, and Climate Action and the PEIEC that the original interconnection assets were approaching end of life, and that the assets should be upgraded within the next ten years.

Dedicated meetings between Maritime Electric and the PEIEC on the replacement of Cables 1 and 2 began in May 2025. Maritime Electric and the PEIEC met with Natural Resources Canada in early 2026 to discuss funding opportunities for pre-development work. As the Provincial Government is the owner of Cables 1 and 2, detailed questions around the content of these meetings, and interactions with other levels of government, should be directed towards either the PEIEC or the Department of Transportation, Infrastructure and Energy (“PEIDIE”).

b. It is unlikely that Cables 1 and 2 will be replaced before 2030, as the start date of the project remains uncertain. As the Provincial Government is the owner of Cables 1 and 2, questions regarding their replacement should be directed towards either the PEIEC or the PEIDIE.

c. As the Provincial Government is the owner of Cables 1 and 2, questions regarding financing their replacement should be directed to either the PEIEC or the PEIDIE.

Previous Cable Funding
In 1977 and 2016, the cables were funded through a 50/50 cost-sharing arrangement between the federal and provincial governments. The federal government's contribution

[67] Application, page 112, Section 8.1.2 [Exhibit M-1].

was provided as a grant, while the provincial government's contribution was recovered over time from Island ratepayers.

d. Yes. Additional on-Island capacity would still be required in this scenario.

Replacing Cables 1 and 2, constructing the additional transmission facilities in NB, and upgrading the NB-PEI Interconnection will increase the amount of firm transmission capability available between PEI and NB. However, increasing transmission capability does not create additional generating capacity. The ability to import additional electricity during times of high demand in the region depends on both transmission capability and the amount of generation capacity that is available for purchase from neighbouring jurisdictions.

As discussed in the responses to IR-43(a) through IR-43(d), the new generation resources currently being developed in NB, NS, and elsewhere in Atlantic Canada are intended to address the reliability and resource adequacy requirements of those jurisdictions and are not being developed to create significant long-term surplus capacity available for export to PEI.

Maritime Electric's CRAAs already assumes the continued availability of all existing firm off-Island capacity arrangements. However, despite utilizing all currently available firm capacity import capability, the Company remains capacity deficient and requires additional resources to satisfy reliability requirements. The E3 Study, provided as IR-23 - Attachment 1, concluded that additional capacity is required to satisfy the NPCC reliability criterion and identified portfolios that include the proposed Accelerated Capacity Solution.

Therefore, while the replacement of Cables 1 and 2 and related transmission upgrades are important long-term initiatives that will improve system flexibility, reliability, and access to regional energy markets, they do not eliminate the need for the additional on-Island capacity proposed in the December 2024 Application. The upgrading of the NB-PEI Interconnection and the Accelerated Capacity Solution address different constraints within the Island’s electrical system and are complementary components of PEI's long-term security of supply.

IR-46 In 2026, MECL has contracted for 190 MW of firm capacity from NB Power. The existing energy purchase agreement with NB Power is set to expire on December 31, 2026.

a. What firm capacity is available from NB Power in 2027 and subsequent years? Provide supporting documentation/confirmation from NB Power.

b. What is the price (or indicative price) of the capacity from NB Power? Provide supporting documentation/confirmation from NB Power.

c. In the event that MECL can secure additional firm capacity (more than 190 MW) from NB Power, is additional on-Island capacity necessary? Explain.

Response:

a. Discussions between Maritime Electric and NBEM regarding the next energy purchase agreement ("EPA") are ongoing. NBEM has recently indicated that a total of 195 MW, 200 MW and 205 MW of capacity will be available in 2027, 2028 and 2029, respectively.[68] These capacity amounts are slightly higher than the 190 MW values previously indicated by Maritime Electric.

A proposal from NBEM, which includes the capacity amounts listed above, is provided as IR-46 - Confidential Attachment 1.[69] NBEM has indicated that no additional capacity above the amounts listed is available in 2027 and 2028. Some additional capacity may be available beginning in 2029, but the timing is dependent on the commercial operation date of the NB Power RIGS project, and any available capacity would almost certainly only be available on a temporary basis, and more costly than the capacity proposed in the December 2024 Application and the Supplemental Filing.

b. The indicative price of capacity from NBEM is provided in IR-46 - Confidential Attachment 1.[70]

The updated capacity pricing provided by NBEM is slightly higher than what was included in the Company's net present value ("NPV") analysis filed in Maritime Electric's response to IR-16 from Commission Staff on June 10, 2026.[71] The higher pricing from NBEM further supports the Company's previous evidence that installing on-Island generating capacity is less expensive, on a NPV basis, than purchasing capacity from NBEM.

c. Yes. Even in the event that Maritime Electric can secure additional firm capacity (i.e., more than 190 MW) from NBEM, additional on-Island capacity would still be necessary.

The results of the E3 Study, provided as IR-23 - Attachment 1, indicate that an additional 115 MW of perfect capacity is required by 2030 to meet the LOLE standard of 0.1 days per year. The E3 Study assumed that 190 MW of firm capacity was available from NBEM.

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68 As EPA discussions are ongoing, this information does not represent a firm commitment from NBEM.
69 Refer to Firm Block Quantity in the Proposal Scope section.
70 Refer to IR-46 – Confidential Attachment 1, Capacity Pricing Table. As EPA discussions are ongoing, this information does not represent a firm commitment from NBEM.
71 Exhibit M-29, IR-16 – Updated Supplemental Filing Confidential Appendix B (page 5), Inputs table, rows 4 (Year 4) through 6 (Year 6).

Although available capacity amounts from NBEM in 2030 remain unknown, if 205 MW is assumed to be available in 2030, an additional 100 MW of perfect capacity would still be required to meet the LOLE standard of 0.1 days per year.[72,73]

It should also be noted that if the amount of firm capacity available from off-Island could be maximized based on the current transmission capability of the NB-PEI Interconnection, an additional 65 MW of perfect capacity would still be required to meet the LOLE standard of 0.1 days per year.[74]

[72] 115 MW (perfect capacity requirement) - (205 MW - 190 MW) = 100 MW.
[73] With an ELCC of approximately 75 per cent, the ProEnergy Opportunity (100 MW) represents 75 MW of perfect capacity.
[74] 115 MW - (240 MW - 190 MW) = 65 MW. 240 MW, along with 30 MW from Point Lepreau, represents Maritime Electric's share (270 MW) of the maximum firm import transmission capacity of the NB-PEI Interconnection.

IR-47 Refer to Table 10 – Capacity Resource Adequacy Assessment, Existing EPA Capacity Projected into the Future.[75] Provide an updated Table 10 based on the current forecast capacity requirements and the current forecast availability of NB Power capacity (firm and short-term) for each year from 2027 to 2035.

Response:

An updated CRAA is provided in Table IR-47, reflecting the current forecast capacity requirements and expectations regarding the availability of NB Power firm capacity resources. Table IR-47 shows the results without additional on-Island capacity.

TABLE IR-47
2026 Capacity Resource Adequacy Assessment
Existing EPA Capacity Projected into Future
(MW)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Forecast Capacity Requirement	402	412	420	428	436	443	450	457	464	471
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29	29	29
NB Power firm capacity purchases	190	195	200	205	205	205	205	205	205	205
Wind ELCC	26	26	26	26	26	26	26	26	26	26
Demand Response	1	3	10	15	20	21	21	22	23	23
CT1	15	15	15	15	15	-	-	-	-	-
CT2	25	25	25	25	25	25	25	-	-	-
CT3	49	49	49	49	49	49	49	49	49	49
Total Capacity Resources	**335**	**342**	**354**	**364**	**369**	**355**	**355**	**331**	**332**	**332**
Capacity Surplus (Deficit)	(67)	(70)	(66)	(64)	(67)	(88)	(95)	(126)	(132)	(139)

[75] Application, page 45 [Exhibit M-1].

IR-48 MECL states that the cost of purchasing additional capacity from off-Island resources is expected to be comparable to the cost of building additional on-Island generating capacity resources.[76]

a. Provide all evidence and calculations to support this statement. MECL's response must include a detailed side-by-side comparison of the cost to purchase off-Island capacity and the cost to build on-Island capacity resources. The cost analysis must include the cost to build, maintain, operate and finance on-Island capacity resources over their useful life, including generation costs and MECL's forecast rate of return.

b. Are there additional costs associated with owning a capacity resource, as compared to purchasing off-Island capacity? Please explain.

c. Is there a financial benefit for MECL to own the capacity resource, as compared to purchasing off-Island capacity? Please explain and provide any supporting calculations.

Response:

It is important to note that, as discussed in the response to IR-46(a), there is not sufficient additional capacity available to purchase from off-Island.

a. Maritime Electric has provided comparisons of the cost of installing on-Island capacity to the cost of purchasing off-Island capacity to the Commission, along with supporting evidence and calculations, on several occasions. These comparisons were included in the December 2024 Application,[77] the Supplemental Filing[78] and in Maritime Electric's responses to interrogatories from Commission Staff submitted on June 10, 2026.[79] An updated analysis of the cost of on-Island capacity is included in the Portfolio Net Present Value Study ("Portfolio NPV Study") prepared by Maritime Electric and provided as IR-54 - Attachment 1. These comparisons are summarized below.

December 2024 Application

Refer to Section 6.4.3 (Net Present Value Analysis),[80] which stated the following:

> *Table 14 shows the results of a 2024 NPV analysis that compares the costs and avoided costs of the Project, based on installation at a cost of $427 million in 2024. The Table shows that, over the useful life of the Project components and on a present value basis, the Project's costs are expected to be more than offset by the avoided costs, resulting in a positive economic benefit to customers. The Project is estimated to result in savings of approximately 20 per cent compared to doing nothing and continuing to purchase capacity resources and ancillary services from NB Power.*

[76] Application, page 86, lines 4-7 [Exhibit M-1].
[77] Exhibit M-1.
[78] Exhibit M-12.
[79] Exhibit M-29.
[80] Exhibit M-1, page 63.

Table 14 of the December 2024 Application provides a direct comparison of the present value avoided capacity costs and the present value costs of the proposed project.[81] The supporting evidence and calculations were provided in Confidential Appendix E. This analysis included amortization, fixed operating and maintenance costs, debt interest expense, Maritime Electric's equity return and income taxes. The analysis included now-outdated avoided capacity costs from NBEM and did not include fuel costs.

August 2025 Supplemental Filing

Refer to Section 5.0 (Project Cost) under the Net Present Value heading,[82] which stated the following:

> *The NPV analysis demonstrates that the Accelerated Capacity Solution is estimated to result in savings of approximately 50 per cent compared to continuing to purchase capacity resources and ancillary services from NB Power.*

Table 4 of the Supplemental Filing provides a direct comparison of the present value avoided capacity costs and the present value cost of the proposed project.[83] The supporting evidence and calculations were provided in Confidential Appendix B of the Supplemental Filing.[84] This analysis included amortization, fixed operating and maintenance costs, debt interest expense, Maritime Electric's equity return and income taxes. The analysis, however, included now-outdated avoided capacity costs from NBEM and did not include fuel costs.

June 2026 IR Response

Refer to Maritime Electric's response to IR-16 from Commission Staff,[85] which included an Updated Supplemental Filing Confidential Appendix B, based on updated costs for the ProEnergy Opportunity. This analysis included amortization, fixed operating and maintenance costs, debt interest expense, Maritime Electric's equity return and income taxes. The analysis, however, did not include fuel costs.

Previous NPV analyses submitted and outlined herein did not include fuel costs because these costs are assumed to be incurred whether the capacity is located on- or off-Island. If Maritime Electric purchases capacity from off-Island, it must also pay for energy imported from off-Island.

The Portfolio NPV Study includes the most up to date NPV analysis related to the cost of on-Island generation and includes the addition of fuel costs and the value of energy arbitrage.[86] Supporting evidence and calculations are detailed throughout the study. The present value cost results, shown in Table 14 of the Portfolio NPV Study,[87] can be

81 Exhibit M-1, page 64.
82 Exhibit M-12, page 27.
83 Exhibit M-12, page 28.
84 Exhibit M-12(a) and redacted version in Exhibit M-16(a).
85 Exhibit M-29, page1.
86 The inclusion of these costs in the Portfolio NPV Study reflects feedback received through the regulatory process.
87 IR-54 – Attachment Portfolio NPV Study, page 26.

compared to the present value cost of avoided capacity purchases in the previous filings discussed herein.

b. Refer to the response to IR-48(a). Amortization, fixed operating and maintenance costs, debt interest expense, Maritime Electric's equity return and income taxes were included in all previously filed NPV analyses. The Portfolio NPV Study included fuel costs, along with a sensitivity analysis that tested several fuel-cost scenarios. These costs represent the cost of owning and operating a capacity resource.

c. Yes. There is a financial benefit to Maritime Electric for owning a capacity resource, as compared to purchasing capacity from off-Island. This was accounted for and included in the NPV analyses (listed as equity return).

As shown in the previous NPV analyses submitted, there is also a financial benefit to customers, which is indicated by the positive NPV of installing additional generating capacity on-Island. By installing capacity on-Island, customers benefit from the secured cost of capacity over the useful life of the assets, and the reliability advantages of capacity located on-Island.

IR-49 Assume no additional on-Island capacity is approved at this time.

a. Explain how MECL will secure additional off-Island capacity. What is the estimated cost of that off-Island capacity?

b. Based on historical load data, how often and for what duration will rotating outages, load shedding, or other service interruptions occur if no additional on-Island capacity is approved at this time? Provide all supporting calculations and assumptions.

Response:

a. Refer to the response to IR-46(a). The capacity amounts recently proposed by NBEM represent the most up to date availability of NB Power capacity. As explained in the September 11, 2025, Technical Session, the Company is preparing for rotating outages due to capacity shortages.[88]

Maritime Electric has submitted information to the Commission on several occasions that additional off-Island capacity is not available, including in:

- Maritime Electric's response to IR-4 from Synapse;[89]
- Maritime Electric's response to IR-7(d) from Synapse;[90]
- Maritime Electric's response to IR- 2(b) from Synapse;[91] and
- Maritime Electric's response to IR-17(23) from PEIEC.[92]

Refer to the response to IR-46(b) for the most up to date indicative capacity pricing from NBEM. Refer to the response to IR-48(a) for information regarding previously filed NPV analyses that include a comparative evaluation of off-Island capacity costs.

b. As discussed in response to IR-23(a), the E3 Study found that "absent additional resources, in 2030 the [Maritime Electric] system will be exposed to loss-of-load events as frequently as 24 days per year, with individual events ranging from 1 hour to over 24 hours in duration."[93] To achieve a LOLE reliability target of 0.1 days per year, an additional 115 MW of perfect capacity (i.e., ELCC) is required by 2030.[94] Therefore, if no additional on-Island capacity is approved, there will not be sufficient capacity to meet the industry standard LOLE target of 0.1 days per year, as demonstrated in Table IR-49.

88 Exhibit C-12.
89 Exhibit M-6, page 8.
90 Exhibit M-6, page 13.
91 Exhibit M-15, page 4.
92 Exhibit M-21, page 23.
93 IR-23 – Attachment 1 - E3 Study, page 9.
94 IR-23 – Attachment 1 - E3 Study, Section 5.1, page 41.

TABLE IR-49 E3 Study LOLE Results		
Nameplate Capacity Added by 2030	**Perfect Capacity (i.e., ELCC) added by 2030**	**2030 LOLE**
0 MW	0 MW	24 days per year
Additional 15 MW from NBEM[95]	15 MW	0.1 to 24 days per year[96]
Varies by Portfolio	115 MW	0.1 days per year

[95] Refer to IR-46(a), Page 36. 205 MW - 190 MW (assumed in E3 Study) = 15 MW additional.

[96] The E3 Study was not evaluated for the specific scenario of adding only 15 MW of additional firm capacity from NBEM. Accordingly, a 2030 LOLE result is not available for that scenario. The range shown in Table IR-49 reflects that the addition of 15 MW would improve reliability relative to the no-additional-capacity case (24 days per year), but would not be sufficient to achieve the industry standard LOLE target of 0.1 days per year. Determining the specific LOLE associated with an additional 15 MW of capacity would require a separate resource adequacy modelling run. The E3 Study concluded that approximately 115 MW of additional perfect capacity is required by 2030 to achieve the 0.1 days per year LOLE target.

IR-50 Assume only 50 MW of additional on-Island capacity is approved at this time.

a. Explain how MECL will secure additional off-Island capacity. What is the estimated cost of that off-Island capacity?

b. Based on historical load data, how often and for what duration will rotating outages, load shedding, or other service interruptions occur if 50 MW of additional on-Island capacity is approved at this time? Provide all supporting calculations and assumptions.

Response:

a. Refer to the response to IR-49(a).

b. Refer to the response to IR-49(b). The addition of a 50 MW CT installed on-Island has an ELCC (i.e., perfect capacity value) of only approximately 38 MW,[97] which is not sufficient to meet the industry standard LOLE target of 0.1 days per year, as demonstrated in Table IR-50. The addition of 50 MW of on-Island capacity would improve reliability and reduce the probability of loss of load events but falls short of achieving the industry standard LOLE target of 0.1 days per year, indicating that additional capacity would be required.

TABLE IR-50
E3 Study LOLE Results

Nameplate Capacity Added by 2030	Perfect Capacity (i.e., ELCC) added by 2030	2030 LOLE
0 MW	0 MW	24 days per year
15 MW additional from NBEM[98] and 50 MW CT	15 MW + 38 MW = 53 MW	0.1 to 24 days per year[99]
Varies by Portfolio	115 MW	0.1 days per year

97 IR-23 – Attachment 1 - E3 Study, Figure 5-9, page 52. 50 MW thermal units have an ELCC of 75 per cent.

98 Refer to IR-46(a), Page 36.

99 The E3 Study was not evaluated for the specific scenario of adding 15 MW of additional firm capacity from NBEM together with a 50 MW CT. Accordingly, a 2030 LOLE result is not available for that scenario. The range shown in Table IR-50 reflects that the addition of approximately 53 MW of perfect capacity (i.e., 15 MW from NBEM and 38 MW from the 50 MW CT) would improve reliability relative to the no-additional-capacity case (24 days per year) but would not be sufficient to achieve the industry standard LOLE target of 0.1 days per year. Determining the specific LOLE associated with this scenario would require a separate resource adequacy modelling run. The E3 Study concluded that approximately 115 MW of additional perfect capacity is required by 2030 to achieve the 0.1 days per year LOLE target.

Justification for Additional On-Island Capacity

IR-51 According to MECL, its existing on-Island combustion turbines are seldom operated. The existing CTs operated for 123 hours from 2019 to 2023, averaging less than one hour per month.[100] In 2023, MECL's combustion turbines supplied only 0.2 percent of energy needs (2,509 MWh of energy towards the total energy requirement of 1,590,379 MWh). By 2033, MECL forecasts that on-Island generation will increase to 0.8 percent of the company's total energy needs.[101]

a. According to MECL, as of December 2024, the cost of 150 MW of on-Island capacity was anticipated to be $427 million, with the expected accuracy within 30 percent. Provide justification for a capital expenditure of this magnitude for assets that will seldom be used and that currently supply only 0.2 percent of customers' total energy needs.

b. What quantifiable benefit(s) will 150 MW of additional on-Island capacity provide to MECL's customers? Quantify these benefits and provide all supporting calculations and assumptions. For example, if the additional on-Island capacity will result in security of supply, quantify the number, duration, frequency and magnitude of service interruptions with and without the additional on-Island capacity.

Response:

a. Refer to Figure 5 of the December 2024 Application.[102]

Although the CTs supplied only 0.2 per cent of Maritime Electric's energy needs in 2023, they supplied 28.3 per cent of the Company's capacity needs.

Maritime Electric is obligated to secure adequate generating capacity to meet the needs of its customers. Refer to Section 5.1.1 of the December 2024 Application,[103] which states that "Maritime Electric must ensure that it has access to sufficient capacity resources (i.e., sources of power generation) to supply its customers during the system peak without interruption," as legislated by Section 3(a) of the Electric Power Act.

The proposed capital expenditure represents the least cost solution to meet the Company's capacity obligation.

b. As discussed in response to IR-23(a), the E3 Study found that "absent additional resources, in 2030 the [Maritime Electric] system will be exposed to loss-of-load events as frequently as 24 days per year, with individual events ranging from 1 hour to over 24 hours in duration."[104]

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100 MECL Response to Synapse IR-3(f) [Exhibit M-6].
101 Application, page 119, Table 23 [Exhibit M-1].
102 Exhibit M-1, page 18.
103 Exhibit M-1, page 16, line 1-3.
104 IR-23 – Attachment 1 - E3 Study, page 9.

To address Maritime Electric's capacity shortfall, the E3 Study presented ten portfolio options that each has a combined ELCC of 115 MW, which represents the minimum amount of Perfect Capacity additions needed by 2030 to meet the industry standard LOLE target of 0.1 days per year.[105] Portfolio 2 presented in the E3 Study included the addition of a 9 MW 4-hour BESS, 100 MW of thermal generation (e.g., two 50 MW CTs) and 40 MW of thermal generation (e.g., a reciprocating internal combustion engine ("RICE") plant with two 20 MW engines), for a total nameplate capacity of 149 MW and a combined ELCC (i.e., perfect capacity value) of 115 MW.[106] This portfolio represents a mix of capacity additions that is very similar to what Maritime Electric proposed in the December 2024 Application.

In summary, the addition of 149 MW (nameplate) capacity presented in Portfolio 2 will reduce the Company's 2030 LOLE from 24 days per year to 0.1 days per year.

[105] IR-23 – Attachment 1 - E3 Study, Section 5.1, page 41.
[106] IR-23 – Attachment 1 - E3 Study, Table 5-6, page 53.

Alternative Capacity Resources

IR-52 According to S&L, a battery energy storage system (BESS) can be used to shift load but not to generate electricity. From MECL's perspective, are there reliability risks associated with a BESS as a capacity resource compared to a CT or a reciprocating internal combustion engine (RICE)? Please explain.

Response:

Yes, Maritime Electric agrees with S&L. A BESS does not generate electricity, rather, it stores energy produced by other resources and returns that energy to the system at a later time, subject to round-trip efficiency losses.

Reliability risks exist for all resource types. For BESS resources, these risks include state of charge, storage duration, inverter and control system availability, and the availability of resources available to charge the BESS. For thermal resources, these risks include starting reliability, forced outages, and fuel availability.

From a resource adequacy perspective, the reliability risks associated with BESS, CTs, and RICE resources are reflected in the ELCC of each resource. The E3 Study, provided as IR-23 - Attachment 1, evaluates the reliability contribution of each resource relative to perfect capacity (i.e., ELCC). As a result, all of the differing reliability characteristics listed above for BESS and thermal resources are inherently reflected in the resulting ELCC values.

The results of the E3 Study indicate that thermal resources provide relatively consistent reliability contributions as additional capacity is added, with 50 MW CTs and 20 MW RICE units having ELCC values of approximately 75 per cent and 86 per cent, respectively.[107] In contrast, the ELCC of BESS resources declines as storage penetration increases.[108] As a result, increasingly larger BESS installations are required to achieve the same incremental reliability contribution provided by additional thermal generation resources.

The E3 Study presented ten resource portfolios that each achieve the same reliability contribution, as all portfolios provide a combined ELCC (i.e., perfect capacity value) of 115 MW. However, portfolios that rely more heavily on BESS require substantially larger nameplate capacity additions to achieve the same reliability contribution as portfolios that rely more heavily on thermal generation resources.

[107] IR-23 – Attachment 1 - E3 Study, Section 5.3.5, pages 51-52.
[108] IR-23 – Attachment 1 - E3 Study, Section 5.3.3, pages 47-49.

IR-53 In its report, Synapse discusses how a BESS can be used to shift load and reduce winter net peaks. In this way, can MECL use a BESS as a resource to minimize, reduce or defer capital expenditures associated with peak demand? Please explain.

Response:

BESSs can contribute to serving peak demand by charging during lower-demand periods and discharging during peak conditions, which was discussed in Section 8.3 and illustrated in Figure 29 of the December 2024 Application.[109] In this manner, a BESS does not reduce peak load; rather, it serves as a capacity resource that can be employed by the Company to help meet peak demand.

As discussed in the response to IR-52, the amount of capacity value provided by a BESS is reflected in its ELCC. While BESSs can provide closer-to-nameplate capacity value at lower penetration levels, the incremental ELCC contribution of additional BESS declines as more storage is added to the system. As a result, the initial tranches of storage provide capacity contributions comparable to thermal resources. However, as additional storage is added, the incremental capacity contribution declines rapidly.

In Synapse's response to IR-19 from Commission Staff, Synapse stated that "some BESS resources could also be used to reduce or defer capital costs associated with transmission and distribution system capital expenditure needs by reducing the net peak load seen on those electric system elements."[110] Maritime Electric agrees that under certain circumstances, BESSs can reduce or defer certain transmission and distribution system capital expenditures.

For example, reactive power support is required in central PEI, which could otherwise be provided through the installation of capacitor banks. The addition of either a BESS or CTs equipped with synchronous condensing capability can provide this reactive power support,[111] thereby reducing or deferring the need for capacitor bank installations until further load growth occurs.

Accordingly, Maritime Electric agrees that BESSs can minimize, reduce, or defer certain capital expenditures under specific circumstances; however, similar benefits can also be achieved through the ProEnergy Opportunity.

[109] Exhibit M-1, page 113-114.

[110] Exhibit C-26, page 19.

[111] Refer to Section 5.2 of Supplemental Filing [Exhibit M-12], page 20, which confirms the inclusion of synchronous condensing capability for the proposed ProEnergy units.

IR-54 The estimated cost of a 10MW/40 MWh BESS is $2,670 per kW.[112] The lead time for specific BESS equipment is approximately one year, and 18 months for associated electrical components.[113]

In comparison, the cost of the ProEnergy CTs is $3,240 to $3,342 per kW,[114] not including the 5.7 percent increase as of April 2026. The lead time for the ProEnergy CTs is approximately 3.5 years.[115]

a. MECL states that the ProEnergy Proposal is the least cost and most timely solution.[116] Please explain how the ProEnergy Proposal is the least cost and most timely solution. Provide all supporting evidence.

Response:

There is no reference to lead times of 18 months in Maritime Electric's response to IR-1 from Synapse.[117] As indicated in the response, lead times for associated electrical equipment are 2 to 2.5 years.

The lead time for the ProEnergy CTs is also not 3.5 years. Assuming that the 3.5 years is referring to the October 2029 timeline provided in the Capacity Pricing Update Letter filed with the Commission by Maritime Electric in April 2026,[118] the October 2029 timeline represents the commercial operation date. "Lead times" refer to the time required for delivery to site and "commercial operation" refers to the time at which point the project is operational.

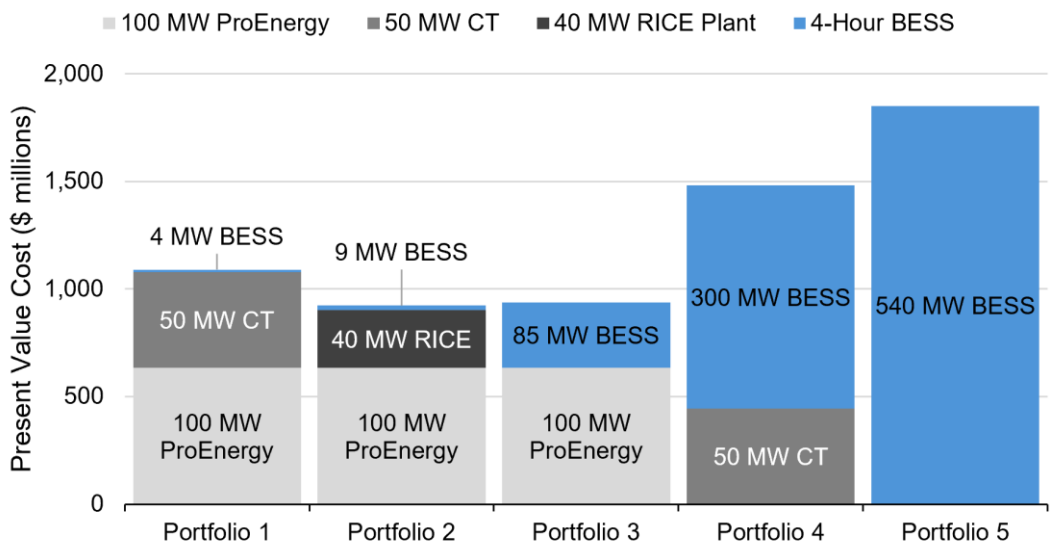
Based on the updated ProEnergy Equipment Payment Schedule provided in Confidential Attachment 1 of Exhibit M-28,[119] the lead time for the ProEnergy CTs is approximately 32 months (i.e., 2.7 years).

a. Refer to the Portfolio NPV Study prepared by Maritime Electric, provided as IR-54 - Attachment 1.

The Portfolio NPV Study provides a comprehensive and consistent quantitative comparison of the portfolio options from the E3 Study to meet Maritime Electric's 2030 capacity needs. By aligning all portfolios on a common ELCC basis, the study enables a direct comparison of capacity resource costs over a 50-year study period, addressing a limitation of earlier NPV analyses. The base case results of the Portfolio NPV Study are shown in Figure IR-54.

112 MECL Response to Synapse IR-12(b) [Exhibit M-6].
113 Application, page 66, lines 2-9 [Exhibit M-1]; MECL Response to Synapse IR-1(a) [Exhibit M-15].
114 Supplemental Application, pages 6, 25 [Exhibit M-12].
115 Exhibit M-28.
116 Exhibit M-28.
117 Exhibit M-15, page 1.
118 Exhibit M-28.
119 Updated Exhibit M-12, Table 1.

FIGURE IR-54
Base Case Portfolio NPV Study Present Value Cost Comparison



The results of the Portfolio NPV Study demonstrate that Portfolios 2 and 3, which include the ProEnergy Opportunity, have the lowest present value cost. The two portfolios (Portfolios 4 and 5) that do not include the ProEnergy Opportunity have the highest present value cost. These findings are consistent across all sensitivity tests performed in the sensitivity analysis component of the study.[120]

The statements related to the ProEnergy Opportunity being "most timely solution" are made in the context of a solution that is effective in addressing the Company's capacity needs. The in-service timelines of the ProEnergy Opportunity are attractive compared to purchasing new CTs from other vendors, such as General Electric Vernova ("GE"). Although BESSs may have faster in-service timelines than the ProEnergy Opportunity, the results of the E3 Study indicate that approximately 300 MW of 4-hour BESSs would be required to match the reliability contribution of the ProEnergy Opportunity.[121] The Company's opinion is that this magnitude of BESS is not realistic and would require significant time for engineering and land acquisition, likely resulting in a longer timeline than the ProEnergy Opportunity, while also resulting in higher overall costs than the portfolios preferred in the accompanying Portfolio NPV Study.

Maritime Electric submits that the ProEnergy Opportunity is the least cost and most timely solution that is effective in addressing at least a portion of the Company's capacity deficit.[122]

[120] Refer to Portfolio NPV Study, Table 16 (page 29) for the sensitivity analysis results.
[121] IR-23 – Attachment 1 - E3 Study, Figure 5-10, which shows that 100 MW (or 2 x 50 MW) of thermal generation (e.g., ProEnergy Opportunity) in Portfolio 3 has an ELCC of 75 MW. Similarly, 300 MW of 4-hour BESS has an ELCC of 77 MW.
[122] As per the results of the E3 Study, the ProEnergy Opportunity would address 75 MW of the 115 MW need by 2030.

IR-55 MECL describes RICEs as being the most cost-effective opportunity to increase on-Island capacity while achieving multiple added benefits, including improved operating efficiencies and the best future fuel flexibility.[123]

a. Despite the lower cost and added benefits, in its Supplemental Application, MECL is no longer proposing any RICEs. Explain why.

b. Provide a side-by-side comparison of a new RICE plant and a refurbished ProEnergy CT. The comparison must include (but should not be limited to) reliability and performance metrics, available fuel sources, applicable warranties, current delivery time, and installed cost (shown as $ per kW). The source of all data must be included.

Response:

a. As indicated in Maritime Electric's response to IR-16 from the PEIEC, "When the Accelerated Capacity Solution became available, via the NB Power RIGS Project, Maritime Electric transitioned to present that option as it was the most economically viable solution which could be commissioned by 2028".[124]

The ProEnergy Opportunity is also attractive because it has synchronous condensing capabilities, whereas a RICE plant does not. A RICE plant is also likely not suitable for the brownfield site at the Charlottetown Generating Station, as it requires a larger site footprint to accommodate multiple engine units than a comparable CT facility. A RICE plant would likely require a greenfield site, which would extend project timelines.

As discussed during the confidential portion of the September 11, 2025, Technical Session[125] and reiterated in the Technical Session Follow Up Letter, filed on October 16, 2025,[126] the ProEnergy Opportunity addresses only 100 MW of the original 150 MW contemplated in the December 2024 Application. If the Supplemental Filing is approved, Maritime Electric will submit an application to address the remaining 50 MW. The remaining 50 MW may include a RICE plant.[127]

b. As requested, Table IR-55(b) provides a side-by-side comparison of a new RICE plant and the ProEnergy Opportunity. The comparison includes reliability and performance metrics, fuel capability, emissions performance, installed cost, warranties, delivery timelines, and project delivery considerations.

Maritime Electric notes that updated installed cost estimates, commercial operation timelines, and selected commercial information for the RICE plant reference case have been provided by S&L through a July 22, 2026, update letter, provided as IR-55(b) - Attachment 1.

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123 Application, page 106, lines 7-12 [Exhibit M-1].
124 Exhibit M-21, page 20.
125 Exhibit C-12(a).
126 Exhibit M-14.
127 Refer to Portfolio NPV Study. The least cost portfolio (Portfolio 2) included a 40 MW RICE Plant.

TABLE IR-55 Comparison of RICE Plant and ProEnergy PE6000		
	Wartsila 18V50 RICE Plant	**ProEnergy PE6000[128]**
Configuration	5 x 18V50 RICE plant (92 MW total)	2 x 50 MW CTs (100 MW total)
Technology Basis	V-18 cylinder RICE	Aeroderivative CT based on the CF6-80C2
Condition	New	Refurbished[129]
Reliability Basis	99% starting reliability[130]	>99% starting reliability
Performance Guarantees	Current model Wartsila 18V50[131] Gross Output – 18.9 per unit (MW) Gross heat rate – 7,339 (kJ/kWh, lower heating value ("LHV"))	Consistent with ThermoFlow's predicted new and clean P85 performance for previous generation LM6000PC. Gross Output – 50.3 (MW) Gross heat rate – 9,241 (kJ/kWh, LHV)
Fuel Capability	Liquid biofuels, light fuel oil (diesel) or heavy fuel oil.	Dual Fuel (i.e., Natural Gas or Diesel) and hydrogen-capable up to 35% by volume.
Emissions Performance	At the combustion turbine generator ("CTG") flange:[132] NOx – 90 ppm (without selective catalytic reduction ("SCR")) – 5 ppm (with SCR)	Equivalent to an LM6000PC at the CTG exhaust flange. Using an SCR system: NOx - 7.0 ppm CO - 5.0 ppm NH3 Slip - 10 ppm
Installed Cost	Approximately $4,308 per kW	Approximately $3,530 per kW
Warranties	1-year standard warranty[133]	1-year standard warranty 2-year optional extended warranty
Expected Commercial Operation Timeline[134]	Estimated 4 years	Estimated 3.5 years

128 Details on the ProEnergy PE6000 were provided directly by ProEnergy.
129 Refer to the response to IR-72 for further detail on the refurbishment process.
130 https://www.wartsila.com/docs/default-source/power-plants-documents/downloads/white-papers/general/wartsila-bwp-combustion-engine-power-plants.pdf, page 8.
131 https://www.wartsila.com/docs/default-source/energy-docs/technology-products/product-leaflets/wartsila-50sg.pdf?sfvrsn=eeeda345_17
132 https://www.wartsila.com/docs/default-source/power-plants-documents/downloads/white-papers/general/wartsila-bwp-combustion-engine-power-plants.pdf, pages 7-8.
133 Only standard warranty information is available publicly, but it is assumed that a similar two-year optional extended warranty would also be possible.
134 As per the response to IR-54, the expected commercial operation timeline refers to the expected timeline until commercial operation. In the case of the ProEnergy Opportunity, commercial operation is expected approximately ten months after the turbine lead time.

IR-56 The cost of energy produced by CTs is "high",[135] and MECL is forecasting that on-Island generation events will increase.[136]

a. Based on current geopolitical and market conditions, what is the estimated cost to produce energy using CTs, and is this the least cost option to generate on-Island capacity?

b. How does the cost of energy produced by CTs compare to the cost of energy produced by a RICE or a BESS?

Response:

a. Refer to Section 4.6.1 of the Portfolio NPV Study, provided as IR-54 - Attachment 1, for information about Maritime Electric's current cost of producing energy with a CT, which is estimated at $454/MWh.[137] The current cost to produce energy with a RICE plant is estimated at $328/MWh. Schedule 4 of the Portfolio NPV Study provides a forecast for the cost of producing energy with a CT and a RICE, based on a United States Energy Information Administration ("USEIA") forecast.[138]

On a per-MWh basis, CTs do not produce least cost energy. However, given that they are peaking generators, they represent the least cost option for capacity. The Portfolio NPV Study results, which include fuel costs, demonstrate that capacity resource portfolios with the ProEnergy Opportunity have the lowest present value cost.

b. Refer to the response to IR-56(a).

BESSs do not produce energy. BESSs store energy produced from other generation resources; therefore, the cost of charging a BESS varies. Refer to Section 4.7.1 of the Portfolio NPV Study,[139] which estimated that the current average cost to charge a BESS is $200/MWh. Due to BESSs having an estimated round-trip efficiency of approximately 85 per cent (i.e., 15 per cent losses), the cost of energy discharged by a BESS is estimated at approximately $230/MWh.[140]

[135] Application, page 103, lines 13-14 [Exhibit M-1].
[136] Application, page 119, Table 23 [Exhibit M1].
[137] IR-54 – Attachment - Portfolio NPV Study, page 20.
[138] IR-54 – Attachment - Portfolio NPV Study, page 53.
[139] IR-54 – Attachment - Portfolio NPV Study, page 22.
[140] $200/MWh x (1 + 0.15) = $230/MWh.

IR-57 Maritime Electric states that the proposed combustion turbines are expected to operate infrequently as peaking and emergency generation resources.

a. Explain whether there is an annual level of operation (hours or MWH) at which ownership of the proposed combustion turbines would no longer represent the least-cost alternative when compared to purchasing off-Island capacity.

b. If such a threshold exists, identify that threshold and provide all supporting calculations and assumptions.

c. If no such analysis has been completed, explain why not.

Response:

a. Refer to the responses to IR-46(a) and IR-49(a).

This analysis has not been completed because, as indicated in the referenced responses, additional off-Island capacity is not available. As such, it is not a viable alternative.

b. Refer to the response to IR-57(a). Because additional off-Island capacity is not available, no such threshold can be provided.

c. Refer to the response to IR-57(b).

Alternative Fuel Sources

IR-58 In its Application, MECL discusses the federal and provincial government goals to reduce GHG gas emissions.[141] MECL goes on to discuss alternate fuel sources with less carbon impact than diesel that can be used with CTs and RICEs. These alternate fuels include biodiesel, natural gas and hydrogen.

a. According to information contained in the Supplemental Application, the ProEnergy CTs can operate using diesel or natural gas. Please confirm.

b. Can the ProEnergy CTs operate using liquified natural gas, compressed natural gas, or both?

c. What, if any, modifications are required to operate the ProEnergy CTs using natural gas (rather than diesel)? What is the cost of these modifications?

Response:

a. Confirmed.

b. Yes. The proposed ProEnergy PE6000 CTs can operate on natural gas, regardless of whether the natural gas is delivered to the site in compressed or liquefied form.

Compressed Natural Gas ("CNG") and Liquefied Natural Gas ("LNG") are both methods of storing and transporting natural gas. CNG is natural gas that has been compressed to a higher pressure to reduce its volume for transportation and storage. LNG is natural gas that has been cooled to approximately minus 162°C, causing it to condense into a liquid which significantly reduces the volume of the product for storage and transportation.

Regardless of whether natural gas is delivered to the site as CNG or LNG, the fuel must ultimately be converted into its gaseous form and supplied to the CT fuel system at the pressure and operating conditions required by the turbine. CNG systems accomplish this through pressure regulation, while LNG systems require vaporization equipment to convert the LNG back into gaseous form prior to use.

Accordingly, from the perspective of the CT itself, both CNG and LNG are viable means of supplying natural gas fuel, provided the necessary fuel handling, storage, vaporization, compression, pressure regulation, and associated balance-of-plant equipment is installed.

c. The proposed ProEnergy PE6000 units are dual-fuel CTs designed to operate on either diesel fuel or natural gas. In jurisdictions where both fuels are available, dual-fuel CTs are commonly operated using either fuel depending on economic and operational considerations. For example, natural gas prices can increase significantly during periods of peak demand, and operators may elect to temporarily operate on liquid fuel when it is more economical to do so.

[141] Application, page 107, lines 2-4 [Exhibit M-1].

Operation on natural gas would require the installation of fuel receiving, storage, conditioning, and delivery infrastructure appropriate for the fuel supply method (i.e., CNG or LNG) selected. Depending on the configuration, this could include LNG receiving facilities, storage tanks and vaporization equipment or CNG trailers and receiving facilities. Either fuel type would also require pressure regulation equipment, compressors, piping, controls, and associated safety systems.

Maritime Electric has not completed detailed engineering to determine the specific infrastructure configuration, scope of work, or cost associated with operating the proposed units on natural gas.

IR-59 MECL states that liquified natural gas is not a viable option in PEI,[142] while compressed natural gas (CNG) would require the development of transportation pathways, natural gas supply contracts, and on-Island offloading and storage facilities.[143] S&L states that the cost of developing natural gas infrastructure is "*too great to make economic sense for power plants that will be primarily used as backup generators*".[144]

a. As natural gas is not currently a viable option in PEI, explain why MECL is proposing to install 100 MW CTs that operate on natural gas as an alternative to diesel.

b. To date, what has MECL done to develop transportation pathways, natural gas supply contracts, and on-Island offloading and storage facilities?

c. Calculate the capital and operating costs associated with using natural gas as a fuel source over the useful life of the ProEnergy CTs, including the cost of transportation, storage, and infrastructure development.

Response:

a. Maritime Electric is not proposing the development of natural gas infrastructure as part of the Accelerated Capacity Solution. The proposed CTs will initially operate using diesel fuel and are being procured with dual-fuel capability that permits operation on either diesel fuel or natural gas.

The dual-fuel capability is not a unique modification requested by Maritime Electric. The ProEnergy PE6000 units are offered as dual-fuel units as part of their standard configuration. The Company's existing Combustion Turbine No.3 ("CT3") was also procured with dual-fuel capability to provide operational flexibility should natural gas availability, economics, or policy requirements change over the life of the asset.

The inclusion of dual-fuel capability reflects prudent long-term asset planning, rather than a proposal to develop natural gas infrastructure on PEI. Should natural gas or another alternative fuel become commercially available and economically attractive in the future, the proposed CTs have the ability to utilize that fuel without requiring replacement of the generating units themselves.

b. Refer to the response to IR-59(c).

c. Maritime Electric has not completed this analysis.

As discussed in Section 7.7 of the December 2024 Application and in the response to IR-59(a),[145] the Company concluded that natural gas is not a viable fuel supply option for the proposed project at this time. Accordingly, the Company has not advanced natural gas

142 Application, page 109, lines 1-8 [Exhibit M-1].
143 Application, page 108, lines 17-26 [Exhibit M-1].
144 Capacity Resource Study, page 55, Section 4.2.3 [Exhibit M-1, Appendix C].
145 Exhibit M-1, page 107.

infrastructure options beyond the preliminary assessment previously filed in this proceeding.

The analysis requested would require the development and evaluation of a specific natural gas supply solution, including fuel sourcing arrangements, transportation requirements, storage facilities, offloading infrastructure, site layout considerations, operating assumptions, and associated capital and operating costs. The results of such an analysis would be highly dependent on the specific concept evaluated and the assumptions used.

Given that natural gas is not currently considered a viable fuel supply option, the Company has focused its evaluation efforts on alternatives that are capable of meeting the project's requirements within the required timeframe. Should natural gas become a viable option in the future, a more detailed assessment could be completed at that time.

IR-60 A 50 MW CT at full output uses approximately 39 to 49 CNG trucks over a 24-hour period.[146] S&L states that the amount of storage space is too large for CNG to be used as a fuel source at MECL's existing power plants.[147]

a. Does MECL agree with S&L's finding?

b. If yes, what is MECL's proposed solution, and what is the forecast cost of that solution?

Response:

a. Yes, Maritime Electric agrees with S&L's conclusion. The amount of CNG required to support extended operation of a 50 MW CT is substantially greater than can be practically stored on-site using conventional CNG storage approaches.

However, Maritime Electric notes that S&L's assessment considered the use of natural gas as a primary fuel source. The Company believes there may be future scenarios where CNG could be used as a supplemental or partial fuel supply option, rather than as the sole fuel source.

For example, Maritime Electric currently maintains liquid fuel storage sufficient to support approximately one week of operation of its existing CT3 at full load. Replicating an equivalent duration of storage using compressed natural gas would likely not be practical at the Charlottetown Generating Station. However, in the future, CNG could be delivered and stored on site in quantities sufficient to support operating requirements of shorter durations.

The amount of storage required would depend on operating patterns and dispatch requirements. For example, a future arrangement may support a number of routine operating hours each month using compressed natural gas while preserving diesel fuel for extended operation, emergency conditions, or periods of elevated demand.

b. Refer to the responses to IR-59(a), IR-59(c), and IR-60(a). Maritime Electric is not proposing a CNG fuel supply solution as part of the Accelerated Capacity Solution and has therefore not identified a preferred storage or supply configuration or estimated the associated costs. As discussed in those responses, natural gas is not considered a viable fuel supply option for the proposed project at this time, and the Company has not completed the engineering, siting, storage, fuel supply, or economic studies necessary to develop or cost a specific solution.

[146] Application, page 108, lines 19-20 [Exhibit M-1].
[147] Capacity Resource Study, page 55, Section 4.2.3 [Exhibit M-1, Appendix C].

IR-61 MECL states that the long-term alternate fuel choice for the proposed on-Island generation should be made in conjunction with the long-term alternate fuel plan and strategy for the province and the region.[148]

a. What is the long-term alternate fuel plan and strategy for the province and region?

b. How do the ProEnergy CTs align with this strategy?

c. What are the forecast stranded costs if future expenditures are required to accommodate alternate fuels?[149]

Response:

a. Maritime Electric is not aware of any published provincial or regional strategies of this nature. The Provincial Government recently released the PEI Energy Strategy, which establishes high-level objectives related to reliability, affordability, sustainability, clean energy development, and energy storage;[150] however, the document does not contain a long-term alternate fuel plan and strategy.

b. Refer to the responses to IR-60(b) and IR-61(a).

The proposed ProEnergy units will be supplied with dual-fuel capability, which preserves future flexibility should natural gas or other alternative fuel supply options become available and economically attractive during the life of the asset.

Maritime Electric notes that a number of alternative fuel products are being explored across the electricity industry, including renewable diesel, biodiesel blends, hydrogen, and ammonia.

c. Refer to the responses to IR-59(a) and IR-60(a). If natural gas or alternative fuels become available, Maritime Electric expects that they may be used as a supplementary fuel source. Therefore, there would not be any stranded costs, as diesel fuel infrastructure is expected to be maintained.

[148] Application, page 110, lines 13-15 [Exhibit M-1].
[149] Application, page 110, lines 15-16 [Exhibit M-1].
[150] PEI Energy Strategy, Dunsky Energy + Climate Advisors, August 2025: https://www.princeedwardisland.ca/sites/default/files/fe81/PEIEnergyStrategy.pdf

IR-62 What fuel source will be used by the RIGS Energy Atlantic Project in New Brunswick?

Response:

NB Power's RIGS Project is expected to operate primarily on natural gas; however, the facility is being developed as a dual-fuel project with on-site diesel storage and the ability to operate on either natural gas or diesel.[151] NB Power indicates that, due to the anticipated low capacity factor of the facility, natural gas is expected to be sourced from short-term markets using non-firm gas transmission service.[152] NB Power concluded that relying solely on natural gas would introduce energy security risks and that a dual-fuel design was more cost effective than maintaining firm gas transportation rights.[153] Accordingly, while the facility is expected to operate primarily on natural gas, it will retain the ability to operate on diesel for reliability and economic reasons.[154] NB Power also notes that the dual-fuel design preserves optionality for future renewable gaseous or renewable liquid fuels.

[151] NB Power references fuel oil as the liquid fuel to be used for the RIGS Project. Fuel oil and diesel are the same product.

[152] NB Power Corporation, *Renewables Integration and Grid Security Project Evidence*, October 31, 2025, Section 3.2.5 - Combustion Turbines, page 23.

[153] NB Power states: "These factors add some risk to a single fuel source and due to expected low utilization of RIGS, the value of firm gas transmission would be challenged. Dual-fuel is more cost effective and is consistent with the approach taken by gas generation facilities in ISO-NE." NB Power Corporation, *Renewables Integration and Grid Security Project Evidence*, October 31, 2025, Section 3.2.5 - Combustion Turbines, page 23.

[154] NB Power states: "The Facility is expected to run primarily on natural gas, but it will be 'dual-fuel', meaning it is also capable of generating using fuel oil with onsite storage. Fuel oil will ensure power generation reliability in the event of a natural gas shortage while presenting economic opportunity when fuel oil is cheaper on a per MWh basis (typically in January and February)." NB Power Corporation, Renewables Integration and Grid Security Project Evidence, October 31, 2025, Section 4.2.3.3 – The Facility, page 38.

IR-63 Explain the impact that the proposed use of diesel fuel in this Application, rather than the fuel source identified in response to IR 62, is expected to have on the operating cost of the proposed combustion turbines and the resulting cost of electricity supplied to PEI customers. Provide supporting calculations and assumptions.

Response:

Refer to the response to IR-62.

Maritime Electric does not have information regarding the expected proportion of generation from natural gas and diesel for the RIGS Project. As a result, it is not possible to make a direct comparison between the operating costs of the RIGS Project and the proposed Maritime Electric project.

While a direct comparison between the RIGS Project and the proposed Maritime Electric project is not possible, publicly available information does permit a comparison of representative generation fuel costs. The Company notes that the Portfolio NPV Study, provided as IR-54 - Attachment 1, estimated an average generation cost of approximately $454/MWh for diesel-fired CT generation in 2026. For comparison, NB Power's 2023 Integrated Resource Plan ("IRP"),[155] Appendix C, reported a fuel-related levelized cost of energy ("LCOE") of approximately $114/MWh for a simple-cycle CT operating on natural gas.[156]

However, the NB Power analysis assumed a lower heat rate than Maritime Electric's assumptions. Adjusting the NB Power value to Maritime Electric's heat rate assumption of 11,638 British thermal units ("BTU") per kWh increases the estimated fuel-related cost from $114/MWh to approximately $140/MWh. Furthermore, escalating the $140/MWh fuel cost from 2023 to 2026 natural gas prices, based on natural gas pricing information from the USEIA, results in a current estimated cost of $196/MWh.[157]

Table IR-63 shows calculations of the approximate annual fuel cost impact under three simplified operating scenarios, using these production costs and assuming the proposed 100 MW facility operates at a 3 per cent annual capacity factor.

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155 https://www.nbpower.com/media/1492472/2023-integrated-resource-plan-en.pdf

156 The NB Power value is based on an assumed heat rate of approximately 9,460 BTU/kWh. By comparison, the $454/MWh value was derived using actual operating performance from CT3 and reflects an average heat rate of approximately 11,638 BTU/kWh. The Company believes this value is more representative of expected CT operation on PEI, as it reflects actual unit performance across a range of operating conditions, including part-load operation and both winter and non-winter operating periods.

157 According to USEIA natural gas pricing data for Henry Hub, the average natural gas price was $3.7/Million Btu from December 2022 to February 2023 and $5.2/Million Btu from December 2025 to February 2026, representing an escalation of 1.4. $140/MWh x 1.4 = $196/MWh.

TABLE IR-63 Comparison of 100 MW CT Fuel Costs Using Diesel and Natural Gas				
Item	**Reference**	**Diesel Operation**	**Natural Gas Operation**	**50% Diesel/ 50% Natural Gas**
Assumed Cost of Generation ($/MWh)	A	454	196	325[158]
Annual Production (MWh)[159]	B	26,280	26,280	26,280
Estimated Annual Fuel Cost ($ x million)	C = A x B	11.9	5.2	8.5
Percentage of 2025 Forecast Revenue Requirement (%)	C / $255.1 million[160]	4.6	2.0	3.3

[158] ($454/MWh + $196/MWh) / 2 = $325/MWh.
[159] 100 MW × 8,760 hours × 3% = 26,280 MWh.
[160] $255.1 million represents the 2025 forecast revenue requirement per GRA Negotiated Settlement, filed with the Commission on April 4, 2023.

Government Policy & Regulations

IR-64 How does the ProEnergy Proposal align with the Province's target of net zero emissions by 2040?[161]

Response:

Refer to Section 9.4 (Impact on PEI Greenhouse Gas Emissions Goals) of the December 2024 Application,[162] which states that "The Company's generation-related GHG emissions are forecast to be less than 1 per cent of the total PEI GHG emission target of 1.2 megatonnes ("Mt") of CO_2e [carbon dioxide equivalent] by 2030." An illustrative comparison of the Company's forecast generation-related emissions and the PEI target is provided in Figure 32 of the same section.[163]

As a result, the ProEnergy Opportunity is not expected to materially impact the Government of Prince Edward Island's (the "Province") targets.

The Province's most recent Energy Strategy, released in August 2025, states the following:[164]

> *Recognizing that electricity supply, even in times of peak demand, must be reliable, the government supports the installation of dispatchable generators on the Island. These units would not be expected to provide baseload energy, but would instead provide security of supply in times of high demand or reduced supply from clean resources.*

This demonstrates that, despite the Province's emission targets, the Province recognizes the need for and supports the installation of dispatchable generators.

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161 Application, page 118, line 2 [Exhibit M-1].
162 Exhibit M-1, page 122.
163 Exhibit M-1, page 24.
164 PEI Energy Strategy, Dunsky Energy + Climate Advisors, August 2025: https://www.princeedwardisland.ca/sites/default/files/fe81/PEIEnergyStrategy.pdf

IR-65 Since the Application was filed in December 2024, the Federal Government has introduced Clean Electricity Regulations (CER) that aim to create a net-zero electricity grid by 2050.

a. What impact do the CER have on MECL's proposed 100 MW of diesel-operated CTs?

b. Is the ProEnergy Proposal consistent with the CER?

c. Is there a risk that diesel-operated CTs will become stranded assets in the future due to a change in provincial or federal government regulations?

d. If yes, who bears that risk and any resulting financial implications – MECL or its customers?

Response:

a. The Canada Clean Electricity Regulations ("CER") were finalized in December 2024,[165] and represent the current greenhouse gas emissions standards applicable to the ProEnergy CTs.

Refer to Figure 34 of the December 2024 Application, which illustrated the draft CER emission limits.[166] The emission limits in the current version of the CER were increased relative to the draft version referenced in the December 2024 Application and are now more than double the limits contemplated under the draft regulations.[167]

The CER emission limits are applicable from 2035 to 2049. After 2049, thermal generators may continue operating with the use of Canadian Offset Credits. However, in May 2026, the Government of Canada released a *Powering Canada Strong: A National Strategy for an Electrified Canadian Economy* strategy, which announced that the Government intends to amend the CER "to enable the sector to grow more rapidly across all provinces and territories by providing greater flexibility to offset residual emissions elsewhere."[168]

The strategy also acknowledges that certain remote and northern communities, as well as jurisdictions with limited access to natural gas infrastructure or transmission interconnections, will continue to rely on thermal generation resources to maintain reliable electric service. Maritime Electric understands that the Government's stated intention to provide additional flexibility within the CER framework reflects, in part, the need to accommodate these types of system circumstances. Accordingly, the Company anticipates that future amendments to the CER may include provisions or exemptions applicable to utilities, similar to Maritime Electric, that continue to require thermal generation resources for reliability and security of supply purposes. However, the scope and details of any such amendments remain uncertain at this time.

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165 https://gazette.gc.ca/rp-pr/p2/2024/2024-12-18/html/sor-dors263-eng.html
166 Exhibit M-1, page 125.
167 The emission intensity standard increased from 30 to 65 tonnes of carbon dioxide per gigawatt-hour.
168 https://natural-resources.canada.ca/energy-sources/electricity-infrastructure/powering-canada-strong-national-strategy-electrified-canadian-economy

b. The ProEnergy CTs are not expected to exceed emissions limits prescribed in the CER from 2035 to 2050. After 2050, the ProEnergy CTs are expected to still comply with the current CER with the use of Canadian Offset Credits. Maritime Electric is monitoring for expected upcoming amendments to the CER.

c. Given the current CER and Government of Canada intentions to amend them to enable greater flexibility, Maritime Electric believes that the risk of diesel-fired CTs becoming stranded assets is low.

If federal or provincial government regulations were to be put in place before the end of the useful life of these assets, there would need to be associated transition regulations similar to the phase-out of coal generation facilities for the electricity industry to transition to alternate generation. This would allow the Company to prepare a plan to recover the remaining book value of the assets before the assets become stranded; such a plan would be subject to regulatory approval at that time.

Refer to Maritime Electric's response to IR-22(c) from Commission Staff,[169] which states the following:

> *In the event of a more severe or sustained disruption to diesel fuel availability, the proposed combustion turbines are designed with dual-fuel capability, providing the ability to transition to alternative fuels. This includes the potential use of compressed or liquefied natural gas transported to the Island and supplied to the CGS, as well as the ability to convert to other fuels such as hydrogen or ammonia as supply chains mature.*

The ability to utilize alternate fuels partially mitigates this risk.

d. If CTs become stranded assets in the future, Maritime Electric would seek to recover the remaining net book value from customers. This is appropriate for the following reasons:

- Recovery of the full cost of the asset is part of the Regulatory Compact. The Company is investing in and building these assets under the explicit regulatory agreement to provide reliable power to customers and if approved by the Commission, it should be done on the basis that the Commission considers the full cost of the assets to be prudent and fully recoverable from customers.
- Full recovery is necessary to ensure the future financial integrity of the Company. Forcing the Company to absorb the loss associated with a stranded asset will negatively impact the Company's credit rating. A lower credit rating will, in turn, increase borrowing costs, and ultimately lead to higher rates for customers.
- To allow the Company to continue to meet its legislated obligation to serve customers, the Company will need a stable balance sheet to attract the economical capital investment required to build an alternate capacity resource necessary to replace the CT fleet should such legislation be put in place.

[169] Exhibit M-29, page 15.

IR-66 The ProEnergy Proposal, if approved, requires an Environmental Impact Assessment from the Provincial Government and permit(s) from the City of Charlottetown.[170]

a. Provide particulars of all permits and government approvals (all levels) required for the ProEnergy Proposal.

b. Provide the status of each required approval/permit.

Response:

a. Refer to Section 7.0 of the Supplemental Filing, which describes the anticipated permitting and approvals process associated with the Accelerated Capacity Solution.[171]

b. Refer to Section 5.5 of the Supplemental Filing.[172] In the Supplemental Filing, Maritime Electric requested Commission approval to establish a deferral account, which would have enabled Maritime Electric to proceed with permitting activities, and other early-stage project development activities. As Commission approval for the deferral account has not been granted, the Company has been unable to begin permitting activities. Accordingly, there has been no change in the status of any required approvals or permits.

[170] Supplemental Application, page 24, lines 5-13 [Exhibit M-12].
[171] Exhibit M-12, page 36.
[172] Exhibit M-12, page 28.

GHG Emissions

IR-67 What are the current applicable emissions standards, and do the ProEnergy CTs comply with these standards? Provide all supporting evidence.

Response:

The proposed ProEnergy CTs are dual-fuel units capable of operating on either natural gas or diesel. The applicable Federal nitrogen oxides ("NOx") guideline for natural-gas-fired CT operation is 25 parts per million ("ppm") by volume, dry basis, corrected to 15 per cent oxygen for each 50 MW unit. The minimum performance guarantee provided by Pro Energy is 7.0 ppm NOx.[173] There are currently no known guidelines or specific NOx concentration limits for diesel-fueled CTs.

Refer to the responses to IR-65(a) and IR-65(b) for information regarding the ability of the ProEnergy CTs to meet the emission standards of the CER.

[173] Refer to Exhibit M-28(c), Emissions Table, page 7.

IR-68 Refer to the Application at page 122, Figure 30 – Generation GHG Emissions Forecast Comparison. Update this Figure to show the forecast GHG emissions from the ProEnergy CTs over their useful life. Assume the CTs will operate using diesel.

Response:

The addition of the ProEnergy CTs is not expected to change the GHG emissions forecast in Figure 30 of the December 2024 Application materially. As described in Section 9.3 of the December 2024 Application:[174]

> *"The addition of the BESS, CT4 and the RICE plant, as well as the retirement of CT1 and CT2, are expected to result in lower GHG emission increases compared to the Company continuing to rely solely on CT1, CT2 and CT3 to fulfill its future generation requirements. Figure 30 compares the estimated annual generation-related GHG emissions with and without the Project. The Figure demonstrates the GHG emission impacts of utilizing more fuel-efficient generation resources."*

The same logic is true for the ProEnergy CTs, which are more efficient than Maritime Electric's Combustion Turbine No.1 ("CT1") and Combustion Turbine No. 2 ("CT2").

A benefit of the ProEnergy CTs is that they include a selective catalytic reduction ("SCR") system, carbon monoxide oxidation catalysts and a continuous emission monitoring system, as described in Section 5.2 of the Supplemental Filing.[175] Although these systems do not reduce GHG emissions, they reduce nitrogen oxide and carbon monoxide emissions and provide real-time emissions monitoring capabilities. These systems are improvements compared to Maritime Electric's existing CTs, which do not have these capabilities.

Maritime Electric has not completed a GHG emissions forecast for the ProEnergy CTs over their useful life, as such a forecast would require assumptions over a 50-year period regarding future load growth, dispatch, fuel use, future system conditions, market conditions and resource additions, all of which are subject to significant uncertainty.

Table IR-68 provides estimated annual GHG emissions for the ProEnergy CTs, modelled based on Maritime Electric's CT3, using annual capacity factor scenarios of 1 per cent, 3 per cent and 5 per cent. The table also shows the estimated annual emissions for each scenario as a percentage of PEI's total 2030 GHG emission target of 1,200 kilotonnes ("kt") of carbon dioxide equivalent ("CO_2e").

[174] Exhibit M-1, page 120-121.
[175] Exhibit M-12, page 20.

TABLE IR-68 ProEnergy CTs Annual Emissions Scenarios				
Annual capacity factor scenarios	**A**	**1%**	**3%**	**5%**
Annual gross generation (GWh)	B = 100 MW x A / 8760	8.8	26.3	43.8
Estimated diesel consumption (cubic metres)	C = B x 317.6[176]	2,794	8,353	13,911
Annual estimated GHG emissions (kt CO_2e)	D = B x 0.939[177]	8.3	22.4	37.4
Per cent of PEI 2030 GHG emission target	E = D / 1,200 kt CO_2e	0.7%	1.9%	3.1%

[176] 317.6 represents average cubic metres per GWh from 2019 to 2023 for CT3. Refer to Exhibit M-1, Table 24, page 120, of the December 2024 Application.

[177] 0.939 represents average kilograms of CO_{2e} in 2024 for CT3.

ProEnergy Proposal

IR-69 What are the sustaining capital expenditures required for the ProEnergy CTs over their useful life?

Response:

The Company has not developed an exhaustive list of sustaining capital expenditures required for the ProEnergy CTs over their useful life. However, an approximation of such expenditures is included within the operation and maintenance ("O&M") allowance used in the Company's NPV analyses. Specifically, the year-1 O&M cost for the ProEnergy CT package is approximately $1.197 million, as shown in the NPV inputs and summary tables, and this allowance is escalated annually by two per cent to reflect inflation over the life of the asset.

The O&M values are derived from the fixed and variable operating cost estimates developed by S&L in the Capacity Resource Study Addendum,[178] and have been consistently applied throughout the Company's rate impact calculations and NPV analyses.

[178] Refer to Exhibit M-1, Appendix D, Addendum to December 2022 Maritime Electric Capacity Resource Study, Appendix A – New Thermal Generation Cost Estimates, Page A-1.

IR-70 ProEnergy is based in the United States.

a. Will tariffs apply to the purchase of goods and/or services from ProEnergy?[179]

b. If yes, how much are the tariffs?

c. Are the tariffs included in the project costs filed by MECL?

Response:

a. Tariffs are generally applicable to the cross-border movement of goods and do not apply to the provision of services.

As ProEnergy is based in the United States ("US"), any applicable US tariffs relate to Canadian goods exported into the US and are therefore not applicable to this project.

However, Canadian tariffs, including any retaliatory or counter tariffs, may apply to equipment and materials imported into Canada from the US. As a result, tariffs could apply to the ProEnergy CT package being imported into Canada, but would not apply to services provided by ProEnergy, such as engineering, procurement, or construction services.

Based on the applicable Harmonized Tariff Schedule ("HTS") classification codes, there are exemptions applicable to gas turbines, their packages, and much of the electrical equipment. As a general approximation, the total import tariff impacts to the project are expected to be less than one per cent on the turnkey EPC value due to the fact that site work will be carried out by local subcontractors using local consumables.

Maritime Electric further notes that there are no commercially available packaged CT options manufactured in Canada. Accordingly, regardless of the equipment supplier selected, the procurement of CT equipment would require importation into Canada and may therefore be subject to applicable Canadian tariff regimes.

b. Refer to the response to IR-70(a). To date, any tariffs reflected in budgetary proposals provided to Maritime Electric have been minimal (i.e., approximately one per cent of the total turnkey EPC value). Historical tariff levels, however, are not determinative of future costs, as tariff regimes are subject to change.

c. Any applicable tariffs in effect at the time the budgetary proposals were prepared were reflected in those cost estimates to the extent known by the vendor.

Maritime Electric notes that tariffs are generally applied at the time goods are imported into Canada, rather than at the time contracts are executed. As a result, while tariff assumptions may be updated at the time of contract execution, the final tariff costs applicable to the project will depend on the tariff regime in place at the time of delivery.

Accordingly, there remains a degree of uncertainty with respect to final tariff costs. The project would bear the risk of any changes in tariffs up to the point of equipment import.

[179] Exhibit M-12 - Supplemental Filing, Section 7.2, Page 37.

IR-71 In its Capacity Resource Study, S&L describes MECL's three most critical needs to include "*achieving sustainability targets*". These targets include reducing MECL's GHG emissions by 55 percent by 2030 (from 2019 levels).[180] How will the ProEnergy Proposal achieve this target?

Response:

Refer to Section 6.1.2 Meeting Sustainability Targets in the S&L Capacity Resource Study, which identifies the addition of utility-scale onshore wind and solar photovoltaic facilities ("PV") as resource options to achieve the target.[181]

In 2025, Maritime Electric released its 2025 Sustainability Update Report and announced the transition from a corporate GHG emissions reduction target to a Renewable Energy Integration Goal.[182] This goal is to expand on-Island renewable electricity generation sold to customers by 220 MW, as compared to 2019 levels, by 2040.

Maritime Electric notes that the ProEnergy Opportunity is not being proposed as a stand-alone GHG reduction initiative. Rather, the project is being proposed to address the Company's capacity and reliability requirements. However, the Company believes the project will also support the achievement of long-term sustainability objectives by enabling further integration of renewable energy resources on the PEI electrical system.

Refer to Section 7.5 of the December 2024 Application,[183] which states:

> *As the amount of inverter-based renewable energy resources [i.e., wind and solar PV] increases on PEI, the need for additional system inertia will also increase. Installing a generator with a synchronous condenser will benefit the electrical system and help provide this future need.*

The same section explains that CTs do not consume fuel while operating as a synchronous condenser:

> *Typically, synchronous condensers are initially powered by a spinning turbine before they are synchronized to the electrical system, at which time a clutch disengages the turbine from the generator. Once the turbine is disengaged, it is no longer required for the operation of the synchronous condenser, so it shuts down and stops consuming fuel.*

The ProEnergy Opportunity includes synchronous condensers, which support the integration of additional renewable energy sources.

As discussed in the response to IR-29, increasing levels of renewable generation increase the need for flexible dispatchable resources to manage renewable energy variability and respond to

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180 Exhibit M-1, Appendix C, Sargent & Lundy Capacity Resource Study, page 19.
181 Exhibit M-1, Appendix C, Sargent & Lundy Capacity Resource Study, page 79.
182 Maritime Electric 2025 Sustainability Report, page 2. Available at: https://www.maritimeelectric.com/sustainability/sustainability-report/sustainability-report/
183 Exhibit M-1, page 91-92.

hold-to-schedule events. Accordingly, the addition of dispatchable on-Island capacity supports the integration of additional renewable resources while maintaining reliable system operation.

While the ProEnergy Opportunity is not being advanced primarily as a sustainability project, the Company believes it is an important enabling resource that supports the integration of additional renewable generation resources on PEI by providing the dispatchable capacity and system support services necessary to maintain reliable operation of the electrical system.

IR-72 During the refurbishment process, ProEnergy ensures "*the turbine meets or exceeds current performance and reliability standards*".[184] Provide these performance and reliability standards.

Response:

The performance and reliability standards referenced relate to those expected in the industry from other original equipment manufacturer ("OEMs") for new CTs. Specifically, the PE6000's thermal performance characteristics, including emissions, are consistent with predictions in industry-accepted thermal modeling software like ThermoFlow's GTPro for the LM6000PC turbine from GE. ProEnergy's fleet starting reliability has been similarly demonstrated to be greater than 99 per cent, consistent with industry expectations for aeroderivative peaking turbines. The PE6000 features the same major maintenance intervals as new LM6000PC units, including 20,000-25,000 equivalent operating hours until the hot section exchange and 50,000 equivalent operating hours until the first major overhaul.

As described in the Supplemental Filing, the overhaul process ("zero-houring") of the CF6-80C2 core (i.e., the core engine from an aircraft engine platform widely used in commercial aviation) involves the complete disassembly, inspection of all components, and evaluation against design tolerances which meet or surpass OEM tolerances. Components that do not meet these specifications are replaced, and all applicable service bulletins and recommended upgrades are incorporated as part of the refurbishment process. The overhaul process is only related to the high-pressure CF6-80C2 core while the remainder of the low-pressure components are all made new by ProEnergy.

Through this process, the complete PE6000 turbine is restored to a condition that is intended to meet the required performance guarantees for output and efficiency, and reliability expectations consistent with a new CT. The incorporation of service bulletins ensures that the unit reflects current technical and reliability improvements relative to its original manufacture date.

The Company notes that this refurbishment process is not unique to the power generation industry. Similar overhaul programs are routinely used throughout the aviation industry, where aircraft turbine engines are removed from service after reaching prescribed operating hours or starts and are returned to specialized overhaul facilities for complete disassembly, inspection, refurbishment, testing, and return to service. Following overhaul, these engines are routinely reinstalled on commercial aircraft and continue operating in passenger service. The refurbishment process applied to the high-pressure core within the ProEnergy PE6000 units follows the same fundamental principle: the turbine is disassembled, inspected against OEM specifications, refurbished or replaced as required, updated to incorporate applicable service improvements, and tested prior to being returned to operation. The primary difference is that, instead of being reinstalled on an aircraft, the overhauled high-pressure core is incorporated into the PE6000 in a stationary power generation facility.

[184] Supplemental Application, page 16, lines 7-9 [Exhibit M-12].

IR-73 The Application as filed was based on a 50 MW General Electric LM6000 PC combustion turbine.[185] In its Supplemental Application, MECL is now proposing a refurbished 100 MW ProEnergy PE6000 combustion turbine.

a. Provide a side-by-side comparison of a new GE LM6000 combustion turbine and a refurbished ProEnergy PE6000. The comparison must include (but should not be limited to) reliability and performance metrics, available fuel sources, applicable warranties, current delivery time, and installed cost (shown as $ per kW). The source of all data must be included (hyperlinks are acceptable).

Response:

The December 2024 Application contemplated the installation of a single 50 MW GE Vernova Inc. ("GE") LM6000 CT. In contrast, the Supplemental Filing proposed two (2) 50 MW PE6000 CT units, for a total installed capacity of approximately 100 MW. These units are independent machines that can be operated separately or together, providing operational flexibility and improved reliability relative to a single unit configuration.

a. The ProEnergy PE6000 is an aeroderivative gas turbine based on the same CF6 engine family as the GE LM6000 and is designed based on performance, operating characteristics, and maintenance practices consistent with an LM6000PC-class CT.

A side-by-side comparison of the two configurations is provided in Table IR-73(a).

[185] Application, page 47, footnote 68 [Exhibit M-1].

TABLE IR-73(a) Comparison of GE LM 6000 and ProEnergy PE6000		
	GE LM6000[186]	**ProEnergy PE6000**[187]
Configuration	1 x 50 MW CT	2 x 50 MW CTs (100 MW total)
Technology Basis	Aeroderivative CT based on the CF6-80C2	Aeroderivative CT based on the CF6-80C2
Condition	New	Refurbished[188]
Reliability Basis	>99% starting reliability	>99% starting reliability
Performance Guarantees	Current model LM6000PC: Net Output - 51.1 (MW) Net heat rate – 9,068 (kJ/kWh, LHV)	Consistent with ThermoFlow's predicted new and clean P85 performance for previous generation LM6000PC. Gross Output – 50.3 (MW) Gross heat rate – 9,241 (kJ/kWh, LHV)
Fuel Capability	Dual Fuel and hydrogen-capable up to 35% by volume.	Dual Fuel and hydrogen-capable up to 35% by volume.
Emissions Performance	At the CTG flange. Without SCR system:[189] NOx – 42.0 ppm CO – 59.0 ppm	Equivalent to an LM6000PC at the CTG exhaust flange. Using an SCR system: NOx - 7.0 ppm CO - 5.0 ppm NH3 Slip - 10 ppm
Installed Cost ($/kW)	Approximately $5,381 per kW[190]	Approximately $3,530 per kW
Warranties	1-year standard warranty[191]	1-year standard warranty 2-year optional extended warranty
Expected Commercial Operation Timeline[192]	Estimated 5 years	Estimated 3.5 years

186 Performance details for GE LM6000 can be found at: https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/products/gas-turbines/gev-aero-fact-sheets/GEA35743-GEV-LM6000-Product-Factsheet.pdf

187 Details on the ProEnergy PE6000 were provided directly by ProEnergy.

188 Refer to the response to IR-72 for further detail on the refurbishment process.

189 Available emissions performance was based on an LM6000PC CT without SCR. Expected emissions performance for a GE LM6000PC equipped with SCR would be comparable to that of the proposed PE6000 units.

190 Pricing and timeline information for GE LM6000 provided by S&L. Refer to IR-55(b) - Attachment 1.

191 Only standard warranty information is available publicly, but it is assumed that a similar two-year optional extended warranty would also be possible.

192 As per the response to IR-54, the expected commercial operation timeline refers to the expected timeline until commercial operation. In the case of the ProEnergy Opportunity, commercial operation is expected approximately ten months after the turbine lead time.

IR-74 ProEnergy refurbishes the turbines in Sedalia, Missouri, where each unit undergoes testing "*under real-world conditions*".[193]

a. What are the conditions under which the turbines are tested, and how are these conditions the same or different from the conditions under which the turbines will operate in Prince Edward Island?

Response:

a. ProEnergy maintains a test bay at its Sedalia, Missouri facility, which is used to test individual CT units prior to shipment in equipment supply contracts.

However, ProEnergy recently informed Maritime Electric that, for projects executed under a full Engineering, Procurement and Construction ("EPC") arrangement, such as the one contemplated for this project, the completed turbine engines are not performance tested at the Sedalia test bay. Instead, they are installed at the customer's site location within the project-specific packages, commissioned, and tested on site to demonstrate satisfaction with the contractual performance guarantees at the unique site conditions.

Under the EPC arrangement, ProEnergy provides performance guarantees for the project and assumes the associated risk.[194] Accordingly, the proposed CT units will be fully tested and demonstrated in PEI by ProEnergy under actual site conditions following installation and commissioning.

[193] Supplemental Application, page 16, lines 2-3 [Exhibit M-12].
[194] Refer to Exhibit M-28(c), Updated Confidential Appendix C, ProEnergy Budgetary Proposal, page 7.

IR-75 The output of CTs varies based on ambient air temperatures.[195] During the polar vortex in February 2023, parts of Prince Edward Island experienced temperatures as low as minus 45°C.[196]

a. What ProEnergy projects, specifically projects using refurbished PE6000 combustion turbines, have been constructed in climatic conditions comparable to Prince Edward Island?

b. Have the ProEnergy PE6000 combustion turbines successfully operated in climatic conditions comparable to the February 2023 polar vortex? If yes, provide information about the location, dates, duration and performance of the ProEnergy CTs in these conditions.

c. Provide the performance and reliability metrics, including (but not limited to) output, availability, forced outage rate, and cold-start success, for the ProEnergy PE6000 combustion turbines in climates comparable to PEI, and specifically in extreme weather events comparable to the February 2023 polar vortex.

Response:

For clarification, PEI did not experience temperatures as low as minus 45°C during the February 2023 polar vortex. The Environment and Natural Resources Canada Hourly Data Report for February 04, 2023, referenced by the Commission, shows a minimum temperature of minus 26.9°C.[197] The minus 45°C referenced by the Commission corresponds to wind chill. According to the Environment and Natural Resources Canada Glossary of terms, "Wind chill is an index that indicates how cold the weather feels to the average person".[198]

Equipment ratings, including those applicable to CTs and associated balance of plant equipment, are based on ambient air temperature, which is the appropriate metric for assessing performance and operability under cold weather conditions.

a. Currently, there are no PE6000 units operating in climates directly comparable to PEI.

However, the Company notes that NB Power's RIGS Project, which also includes ProEnergy CT packages, is being developed by ProEnergy as a supply-own-operate facility in Centre Village, NB, which has a very similar climate to PEI. Additionally, ProEnergy's contractual obligation would be to ensure equipment is designed suitably for the local climate (in this case, minus 32°C), as would be the design obligation of any other combustion turbine OEM.

Similar to the RIGS Project, ProEnergy intends to engage an East Coast Canadian engineering firm with extensive experience designing facilities for operation in climates similar to PEI. Through the use of proven winterization measures, including weatherized enclosures, heat tracing and insulation, emergency heating systems, and inlet air

195 Application, page 102, footnote 165 [Exhibit M-1].
196 See Environment and Natural Resources Canada Hourly Data Report for February 04, 2023, East Point (AUT).
197 Environment and Natural Resources Canada Hourly Data Report for February 04, 2023, East Point (AUT), hour 05:00.
198 Environment and Natural Resources Canada, Glossary. Available at: https://climate.weather.gc.ca/glossary_e.html

anti-icing systems, the facility will include the measures necessary to ensure reliable operation even during harsh winter conditions.

b. The Company is not currently aware of any PE6000 units that have operated in climatic conditions directly comparable to the February 2023 polar vortex event on PEI.

However, the PE6000 engine is based on the same underlying platform as the GE LM6000, and the Company has direct operating experience with a LM6000 CT (CT3 is an LM6000 CT) in PEI conditions. Additionally, the PE6000 engine is a repurposed aeroderivative engine, which indicates that the engine itself was used on an airplane and designed to withstand ambient temperatures much colder than those experienced on PEI.

Cold-weather performance of the PE6000 is primarily a function of the site-specific balance of plant systems, controls, fuel systems, auxiliary systems, and electrical equipment, all of which must be appropriately designed for the local climate. Maritime Electric has substantial experience operating CTs within PEI's climate and will ensure that the balance of plant systems associated with any new installation are designed to achieve reliable operation under local conditions.

c. As indicated in the response to IR-75(a), there are currently no PE6000 units operating in climates directly comparable to PEI. For performance and reliability metrics, refer to ProEnergy fleet-wide operating statistics from their WattBridge installations, provided by the Company in a letter to the Commission on October 16, 2025.[199]

[199] Exhibit M-14, Letter to Commission – Technical Session Follow Up, October 16, 2025.

IR-76 In July 2025, MECL provided a "Scope of Supply Summary" specific to the ProEnergy Proposal. According to the July 2025 filing, the Design Air Temperature Range for the ProEnergy equipment is 20°F (minimum) to 110°F (maximum).[200]

In April 2026, MECL filed an updated "Scope of Supply Summary" for the ProEnergy Proposal.[201] The April 2026 update states that the Design Air Temperature Range for the ProEnergy equipment is -32°C (minimum) to 43°C (maximum).

a. Explain the change in the minimum Design Air Temperature Range.

b. What modifications/changes to the ProEnergy equipment are required to facilitate this change in the design air temperature range?

c. What (if any) impact does the change in design air temperature range have on the cost of the ProEnergy Proposal?

Response:

a. As discussed during the September 11, 2025, Technical Session, the difference in the minimum Design Air Temperature Range reflects that the initial documentation filed in July 2025 did not fully reflect the intended project configuration.[202]

The April 2026 filing reflects the updated Scope of Supply Summary for the proposed project, including the cold weather package and corresponding design conditions appropriate for operation in the PEI environment.[203] The minus 32°C minimum design temperature is consistent with the required design temperature on the RIGS Project in NB.

b. As described in the response to IR-76(a), the performance and design information in the July 2025 documentation was not updated by ProEnergy to reflect the cold weather package configuration.

The updated Scope of Supply Summary filed in April 2026 reflects the inclusion of the cold weather package and associated design conditions for operation in the PEI environment. The updated documentation includes planned plant and equipment winterization measures, including:

- insulation;
- electric heat tracing;
- electric heating;
- weatherized enclosures; and
- snow covers.

In addition, the CT generator package includes a package air recirculating inlet heating system, which supports operation at low ambient temperatures.

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200 Exhibit M-11, page 9.
201 Exhibit M-28, Exhibit A to the Updated Confidential Appendix D (Slot Reservation Agreement).
202 Refer to Exhibit C-12(a).
203 Refer to Exhibit M-28(d), Updated Confidential Appendix D – Slot Reservation Agreement, Exhibit A, page 7.

These elements represent balance-of-plant and auxiliary system enhancements required to support reliable operation under cold weather conditions, rather than modifications to the CT engine itself. Refer to the responses to IR-75(a) and IR-75(b) for additional information regarding the proposed winterization measures and cold-weather design considerations. Maritime Electric will be actively involved in the design and execution of the project to ensure that the facility is appropriately designed for operation under PEI climatic conditions.

c. As described in the responses to IR-76(a) and IR-76(b), the cold weather package has always been contemplated as part of the proposed project configuration. Accordingly, the updated design air temperature range presented in the April 2026 filing reflects the correct project configuration, rather than a change in scope. As a result, the update to the design air temperature range has no impact on the current project cost estimate.

IR-77 The Scope of Supply Summary provided by ProEnergy does not provide the estimated performance for gross power output or gross heat rate for ambient temperatures below minus 1.11°C.[204]

a. What are the normal operating conditions for CTs in Prince Edward Island?

b. What is the guaranteed gross power output and guaranteed gross heat rate at normal operating conditions in Prince Edward Island?

c. What is the guaranteed gross power output and guaranteed gross heat rate at the minimum and maximum Design Air Temperature Range (-32°C minimum and 43°C maximum)?

Response:

a. In the past 15 years, from 2011 to 2025, the lowest ambient temperature observed near CTs on PEI was minus 30.3°C, and the highest was 37.6°C.[205] Normal operating temperatures for CTs in PEI are typically between those two extremes.

b. The Company does not have guaranteed gross power output and guaranteed gross heat rate values for the PE6000 at every ambient temperature condition, which is consistent with how all CT suppliers handle thermal performance guarantees. Instead, a "guarantee point" is provided for a single ambient condition, and the performance is "corrected" to the actual site conditions using known correction methods established by the American Society of Mechanical Engineers PTC 22 standard.

The Company will establish the selected guarantee point with ProEnergy and the corresponding predicted gross power output and gross heat rate values associated with all other ambient conditions within the design can be demonstrated. For example:

- at a minimum design temperature of minus 32°C, the predicted gross power output and gross heat rate are 48.1 MW and 9,297 Btu/kWh (LHV), respectively; and
- at a high design temperature of 40°C, the predicted gross power output and gross heat rate are 41.3 MW and 9,297 Btu/kWh (LHV), respectively.

These modeled performances at extreme ambient conditions represent the predicted performance of the generating equipment at the specified design temperature limits.

c. Refer to the response to IR-77(b), which provides the predicted gross power output and gross heat rate at the minimum and maximum design air temperatures.

[204] Exhibit M-12, Exhibit A to Confidential Appendix D (Slot Reservation Agreement); Exhibit M-28, Exhibit A to the Updated Confidential Appendix D (Slot Reservation Agreement).

[205] Based on Environment and Natural Resources Canada Hourly Data for Charlottetown Airport and Maple Plains observation stations.

IR-78 The minimum load level of a CT makes it less efficient when small amounts of generation are required. If the generation needed is less than the minimum load level, another source of energy must be reduced to allow the CT to operate. This results in increased operating costs and GHG emissions.[206]

a. What is the minimum load level of the ProEnergy CTs?

b. Refer to the answer in (a) above. How many times in the previous 5 years has the amount of required on-Island generation been less than the minimum load level of the ProEnergy CTs?

c. Estimate the increased operating costs and GHG emissions resulting from the load level of the ProEnergy CTs over their useful life. Provide all assumptions and supporting calculations.

Response:

a. CT manufacturers, including GE and ProEnergy, typically guarantee a minimum operating level of approximately 50 per cent of rated output. However, actual operating experience demonstrates that aeroderivative CTs can routinely operate below this level under appropriate conditions.

For Maritime Electric's existing CT3 unit, with a rated output of approximately 49 MW, a 50 per cent minimum load corresponds to approximately 24.5 MW. However, operating experience indicates that CT3 can reliably operate at lower output levels and is routinely dispatched at loads closer to 15 MW, or approximately 30 per cent of rated output.

Maritime Electric expects the proposed ProEnergy PE6000 CTs to exhibit operating characteristics comparable to CT3, including the ability to operate at output levels below the typically guaranteed minimum load when system conditions require.

b. Maritime Electric does not maintain a record of instances where CTs have been operated at minimum load levels resulting in the reduction of another source of energy to accommodate turbine operation.

However, as discussed in response to IR-78(a), the Company expects the minimum load level of the proposed ProEnergy CTs to be comparable to that of the existing CT3 unit. As a result, the operational impact on the system is not expected to change. When dispatchable generation is required at low output levels, Maritime Electric can operate CT1 or CT2, which have lower minimum output levels.

Accordingly, the addition of the ProEnergy units will not materially change operating costs or GHG emissions associated with minimum load operation.

c. Refer to the response to IR-78(b).

[206] Exhibit M-1, Application, page 57, footnote 89.

It should also be noted that an assessment of the increased operating costs and GHG emissions associated with minimum load operation of the ProEnergy CTs over their useful life would require assumptions over a 50-year period regarding future load growth, dispatch, fuel use, future system conditions, market conditions and resource additions, all of which are subject to significant uncertainty.

In practice, the extent to which minimum load operation impacts system cost and emissions is dependent on how the broader system evolves and is operated over time. For example, the addition of a BESS could allow small amounts of energy to be supplied without operating a CT at minimum load, thereby mitigating the issue of minimum load levels entirely in those circumstances. Similarly, the addition of RICE generation would provide an alternative dispatchable resource with lower minimum load levels that could be utilized when generation requirements are below the minimum load level of CTs.

The Company also notes that the Portfolio NPV Study, provided as IR-54 - Attachment 1, includes CT fuel costs based on historical operating patterns of the Company's existing CT3. As a result, the cost assumptions reflect periods when the CTs may operate at minimum load levels.

Alignment with New Brunswick RIGS Project

IR-79 In its Supplemental Application, MECL states that a reason for the ProEnergy Proposal is the "*economics of participating in a larger order and the potential for sharing mobilization costs of installation contractors*".[207] As of April 2026, the estimated delivery time for the ProEnergy CTs (October 2029) no longer aligns with the New Brunswick RIGS Project.[208]

a. What impact does this have on the cost of the ProEnergy Proposal, including (but not limited to) the ability of cost and resource sharing with the RIGS Project?

Response:

a. Although the timing of Maritime Electric's proposed project no longer fully aligns with the RIGS Project's commercial operation date, the Company understands from ProEnergy that this does not present any material concerns with respect to project execution or cost. Of note, the delivery time for the RIGS packages to support the installation work is notably sooner (i.e., 2027/2028), while the final start-up has been delayed.

The Company also notes that any cost changes associated with the schedule change, up to the time of the ProEnergy budgetary proposal, included in Maritime Electric's April 17, 2026, letter to the Commission,[209] have already been incorporated into the current project cost estimate.

ProEnergy has indicated that it has identified and engaged a group of local contractors to perform the installation work associated with the RIGS Project. While it would be preferable to transition these contractors directly from the NB project to PEI, ProEnergy has advised that it has communicated with these contractors and that they have expressed strong interest in participating in subsequent work following completion of the RIGS Project.

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207 Supplemental Application, page 9, lines 18-20 [Exhibit M-12].
208 Exhibit M-28.
209 Exhibit M-28(c).

IR-80 According to MECL, ProEnergy typically does not pursue projects smaller than 200 MW.[210] MECL states that if the timeframe does not align with the New Brunswick RIGS Project, the opportunity to share resources and benefit from execution synergies may be lost, and ProEnergy may no longer be willing to proceed with MECL's project under the current terms.[211]

a. MECL's project no longer aligns with the New Brunswick RIGS Project. Provide confirmation from ProEnergy that it will proceed with the MECL project.

Response:

Refer to the response to IR-79(a). As indicated in that response, although the schedules of the Maritime Electric project and the RIGS Projects no longer fully align, ProEnergy has indicated that it remains interested in proceeding with the Maritime Electric project.

The ProEnergy budgetary proposal, included in Maritime Electric's April 17, 2026, letter to the Commission,[212] represents confirmation from ProEnergy that it intends to proceed with the Maritime Electric project, subject to finalization of contractual arrangements and regulatory approval.

[210] Supplemental Application, page 16, lines 16-18 [Exhibit M-12].
[211] Supplemental Application, page 29, footnote 35 [Exhibit M-12].
[212] Exhibit M-28(c).

IR-81 The total estimated cost of the ProEnergy Proposal includes two distinct components: (1) equipment supply, and (2) Engineering, Procurement and Construction.[213] Although the Engineering, Procurement and Construction services are "*essential to the overall execution of the project*", an Engineering, Procurement and Construction Agreement between MECL and ProEnergy has not yet been developed.[214]

a. Provide written confirmation from ProEnergy of the cost of the Engineering, Procurement and Construction services for the MECL project.

Response:

a. The EPC portion of the work has always been included as part of ProEnergy's proposal for the Project. The pricing section (page 10) of ProEnergy's budgetary proposal, included in Maritime Electric's April 17, 2026, letter to the Commission,[215] explicitly identifies and separates the scope of work into two categories:

1. Equipment Supply Scope, which includes the PE6000 CT units and associated equipment; and
2. EPC Supply Scope, which includes balance-of-plant equipment and EPC services.

The ProEnergy budgetary proposal represents confirmation from ProEnergy of the cost of the EPC portion of the project. The total project cost in Maritime Electric's April 17, 2026, letter reflects both equipment supply and EPC components required for full project execution.

[213] Supplemental Application, page 17, lines 3-5 [Exhibit M-12].
[214] Supplemental Application, page 18, lines 1-6 [Exhibit M-12].
[215] Exhibit M-28(c).

IR-82 MECL states that the ability to secure Engineering, Procurement and Construction Services is "*directly tied to the timing and alignment with NB Power's Centre Village project*".[216] The timing of the MECL project no longer aligns with the New Brunswick RIGS Project.

a. Provide written confirmation from ProEnergy that it will provide all necessary Engineering, Procurement and Construction services for the MECL project, if approved.

Response:

a. Refer to the responses to IR-79(a) and IR-80(a).

The ProEnergy budgetary proposal, included in Maritime Electric's April 17, 2026, letter to the Commission,[217] represents confirmation from ProEnergy that it intends to proceed with the EPC services, subject to finalization of contractual arrangements and regulatory approval.

[216] Supplemental Application, page 34, lines 22-24 [Exhibit M-12].
[217] Exhibit M-28(c).

Financial Implications

IR-83 Refer to page 11 of Appendix E of the Application. Under the heading "Project Cost", there is a line item for Equity Return. The "total" Equity Return is 153,997,000.

a. What does the Equity Return and the "total" Equity Return represent?

Response:

a. Equity Return refers to the return allowance applied to the equity portion of Maritime Electric's rate base, calculated using the allowed rate of return and allowed equity portion, both approved by the Commission.

The total equity return, shown as $153,997,000 in Appendix E of the December 2024 Application,[218] represents the present value of the equity return over the useful life of the various project components.

[218] Exhibit M-1(a) and redacted version in Exhibit M-16(b), Confidential Appendix E, page 11.

IR-84 The financial analysis filed by MECL to IR-16 is based on a single set of assumptions regarding project cost, operating costs, timing and utilization. Update the Impact on Rate Base, Revenue Requirement and Customer Rates analysis filed in support of the Application assuming each of the following scenarios independently:

a. Capital costs increase by 10 percent;

b. Capital costs increase by 20 percent;

c. The in-service date is delayed by one year;

d. The in-service date is delayed by two years; and

e. Diesel fuel costs increase by 25 percent.

Response:

Since Maritime Electric submitted its response to IR-16 from Commission Staff,[219] the Company has received updated indicative avoided capacity costs from NBEM, as discussed in the response to IR-46. Additionally, based on the findings of the E3 Study, the ProEnergy Opportunity has an ELCC of 75 MW;[220] therefore, the ProEnergy Opportunity is now considered to avoid 75 MW of capacity purchases from NBEM instead of the 100 MW included in previous estimated rate impact calculations.

An updated estimated impact on customer rates, reflecting the updated pricing from NBEM and an ELCC of 75 MW for the ProEnergy Opportunity, is provided as IR-84 - Confidential Attachment 1. The estimated increase is approximately five per cent for benchmark Rural Residential, Urban Residential and General Service customers.

A comparison of the rate impacts provided in the response to IR-16, the updated rate impact reflecting updated pricing from NBEM and an ELCC of 75 MW for the ProEnergy Opportunity, and the rate impacts requested in IR-84(a) and IR-84(b) with capital costs increased by 10 per cent and 20 percent, respectively, is provided in Table IR-84.

TABLE IR-84
ProEnergy Opportunity Updated Estimated Impact on Customer Rates by Rate Class

Customer Class	Exhibit M-29 Response to IR-16	IR-84 Rate Impacts with Updated NBEM Pricing and 75 MW ELCC		
		Updated Rate Impacts	IR-84(a) Capital Costs Increase by 10%	IR-84(b) Capital Costs Increase by 20%
Rural Residential	6.25%	5.18%	6.13%	7.09%
Urban Residential	6.36%	5.27%	6.24%	7.21%
General Service	6.13%	5.08%	6.02%	6.95%

[219] Exhibit M-29, page 1.
[220] IR-23 – Attachment 1 - E3 Study, Section 5.3.5, page 51.

a. An updated estimated impact on customer rates, based on a capital cost increase of 10 per cent, is provided as IR-84(a) - Confidential Attachment 1. The estimated increase is approximately six per cent for benchmark Rural Residential, Urban Residential and General Service customers.[221]

b. An updated estimated impact on customer rates, based on a capital cost increase of 20 per cent, is provided as IR-84(b) - Confidential Attachment 1. The estimated increase is approximately seven per cent for benchmark Rural Residential, Urban Residential and General Service customers.[222]

c. A delay in the in-service date is not expected to change the Impact on Rate Base, Revenue Requirement and Customer Rates, unless the delay results in increased project costs. Regardless of the exact in-service date and if the project costs do not change, the assets will be depreciated over the same period; therefore, amortization, operating costs, debt interest expense, equity return and income taxes would be the same.

   Maritime Electric is unable to predict or quantify whether a delay in the in-service date would materially impact the total project costs.

d. Refer to the response to IR-84(c).

e. Diesel fuel costs are not included in the Estimated Impact on Rate Base, Revenue Requirement and Customer Rates provided in Maritime Electric's response to IR-16 because diesel fuel costs are expected to be offset by avoided energy purchases elsewhere.[223]

   Figure 30 of the December 2024 Application provides an informative illustration.[224] Figure 30 shows the Company's forecast emissions from thermal generation with and without added on-Island capacity. The forecast demonstrates that the addition of on-Island capacity resources is expected to lower emissions, which is representative of diesel fuel consumption and costs, relative to continuing to rely solely on Maritime Electric's existing thermal generation units. Because the addition of on-Island capacity is not expected to increase overall diesel fuel consumption, relative to not adding on-Island capacity, diesel fuel costs were not included in the Estimated Impact on Rate Base, Revenue Requirement and Customer Rates calculations.

   The Portfolio NPV Study, provided as IR-54 - Attachment 1, included diesel fuel costs because the purpose of the Study was to compare the cost of various resource portfolio options. The Portfolio NPV Study includes a sensitivity analysis, which tested a 15 per cent increase in diesel fuel prices, relative to the diesel fuel price forecast.[225] The results

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221 Benchmark Residential Rural and Residential Urban customers include 650 kWh of consumption per month. Benchmark General Service customers include 10,000 kWh of consumption per month. Taxes are excluded from the impact on customer rates.

222 Refer to the response to IR-16 from Commission Staff [Exhibit M-29], which updated the estimated impact on customer rates based on the April 2026 pricing update from ProEnergy. The estimated impact was approximately 6 per cent for benchmark Rural Residential, Urban Residential and General Service customers.

223 Exhibit M-29, page 1.

224 Exhibit M-1, page 122.

225 Refer to IR-54 – Attachment 1 - Portfolio NPV Study, Section 5.1 (page 27), for information on the sensitivity analysis. Refer to IR-54 – Attachment 1 - Portfolio NPV Study, Section 4.6.1 (page 20) for information on the diesel price forecast and an explanation of how the sensitivity test is applied.

of the sensitivity analysis are shown in Table 16 of the study,[226] which demonstrate that a 15 per cent increase in diesel fuel prices increases the present value cost of portfolios with thermal generation but does not impact the conclusions of the study.

A breakdown of the present value cost of the ProEnergy Opportunity with a 25 per cent increase in diesel prices, relative to the diesel fuel price forecast, derived from the Portfolio NPV Study, is shown in Table IR-84(e)(i).

TABLE IR-84(e)(i)
ProEnergy Opportunity Present Value Cost with 25 Per Cent Increase in Diesel Prices ($ millions)

Diesel Fuel Price Scenario	Amortization	Fixed O&M	Fuel Costs	Debt Interest	Equity Return	Current Taxes	Total
Base case	109	24	227	97	123	55	**635**
Diesel price forecast adjustment (+25%)	109	24	284	97	123	55	**692**

The portfolio present value cost results from the Portfolio NPV Study with a 25 per cent increase in diesel prices, relative to the diesel fuel price forecast,[227] are shown in Table IR-84(e)(ii). Under this scenario, Portfolios 2 and 3 still have the lowest present value cost.

TABLE IR-84(e)(ii)
Portfolio Present Value Cost Comparison with Increased Diesel Prices ($ millions)

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Base case	1,081	924	936	1,474	1,852
Diesel price forecast adjustment (+25%)	1,166	997	993	1,502	1,852

[226] IR-54 – Attachment 1 - Portfolio NPV Study, page 29.
[227] IR-54 – Attachment 1 - Portfolio NPV Study includes a diesel price forecast, which already forecasts an increase in diesel prices. The 25 per cent increase is applied to all years of this forecast.

IR-85 Maritime Electric states that the proposed combustion turbines are expected to operate infrequently as peaking and emergency generation resources.

a. Explain whether the Net Present Value analysis and the Impact on Rate Base, Revenue Requirement and Customer Rates analyses filed in response to IR-16 would change if the actual annual operating hours of the proposed combustion turbines differ from those assumed in the Application.

b. If yes, update the Net Present Value analysis and the Impact on Rate Base, Revenue Requirement and Customer Rates analyses assuming annual operation of:

i. 50 hours;
ii. 100 hours;
iii. 250 hours;
iv. 500 hours; and
v. 1,000 hours.

Response:

a. Refer to the response to IR-84(e). An increase in annual operating hours of the proposed CTs would increase fuel costs, but these costs were not included in the Estimated Impact on Rate Base, Revenue Requirement and Customer Rates.

Similarly, NPV analyses submitted in the December 2024 Application,[228] the Supplemental Filing,[229] and in Maritime Electric's response to IR-16 from Commission Staff did not include fuel costs.[230]

However, the Portfolio NPV Study, provided as IR-54 - Attachment 1, included fuel costs because the purpose of the Portfolio NPV Study was to compare the cost of various resource portfolio options. The Portfolio NPV Study includes a sensitivity analysis, which tested a 5 per cent capacity factor for thermal generating units (rather than 3 per cent for the base case).[231] The results of the sensitivity analysis are shown in Table 16 of the study,[232] which demonstrate that a 5 per cent capacity factor for thermal generating units increases the present value cost of portfolios with thermal generation but does not impact the conclusions of the study.

b. A breakdown of the present value cost of the ProEnergy Opportunity with the requested annual operating hours, derived from the Portfolio NPV Study, are shown in Figure IR-85(i). The results assume that the ProEnergy Opportunity CTs, on average, operate at half-load, which is reflected in the capacity factors shown.[233]

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228 Exhibit M-1(a) and redacted version in Exhibit M-16(b), Confidential Appendix E.
229 Exhibit M-12(a) and redacted version in Exhibit 16(a), Confidential Appendix B.
230 Exhibit M-29, page 1.
231 IR-54 – Attachment 1 - Portfolio NPV Study, Section 5.1 (page 28), for information on the sensitivity analysis. Refer to IR-54 – Attachment 1 - Portfolio NPV Study, Section 4.6 (page 19) for information on how capacity factors were used in the Portfolio NPV Study.
232 IR-54 – Attachment 1 - Portfolio NPV Study, page 29.
233 On average, from 2019 to 2023, CT3 operated at 21.3 MWh, which is less than half-load (i.e., 25 MWh).

TABLE IR-85(i) ProEnergy Opportunity Present Value Cost with Various Operating Hours ($ millions)							
Annual Operating Hours (Capacity Factor)	**Amortization**	**Fixed O&M**	**Fuel Costs**	**Debt Interest**	**Equity Return**	**Current Taxes**	**Total**
50 (0.3%)	109	24	23	97	123	55	**430**
100 (0.6%)	109	24	45	97	123	55	**453**
250 (1.4%)	109	24	106	97	123	55	**514**
500 (2.9%)	109	24	220	97	123	55	**627**
1,000 (5.7%)	109	24	432	97	123	55	**839**

The portfolio results of the Portfolio NPV Study with the requested annual operating hours are shown in Figure IR-85(ii).[234] Under all operating hour scenarios, Portfolio 2 and Portfolio 3, which contain the ProEnergy Opportunity, have the lowest present value cost.

TABLE IR-85(ii) Portfolio Present Value Cost Comparison with Various Operating Hours ($ millions)					
Annual Operating Hours (Capacity Factor)	**Portfolio 1**	**Portfolio 2**	**Portfolio 3**	**Portfolio 4**	**Portfolio 5**
50 (0.3%)	771	654	690	1,290	1,729
100 (0.6%)	806	684	717	1,310	1,743
250 (1.4%)	898	764	790	1,365	1,779
500 (2.9%)	1,070	914	927	1,467	1,847
1,000 (5.7%)	1,391	1,194	1,183	1,657	1,974

[234] IR-54 – Attachment 1 - Portfolio NPV Study, Section 3.1 (page 8) for a breakdown of the portfolios.

Provide all supporting calculations and assumptions.

IR-86 Maritime Electric states that the primary purpose of the proposed combustion turbines is to improve reliability and security of supply.

a. Quantify the reliability benefits expected to result from the proposed project, including any reduction in:

i. the probability of rotating outages;
ii. the frequency of rotating outages;
iii. the duration of rotating outages;
iv. expected unserved energy; and
v. any other reliability metrics relied upon by Maritime Electric in support of this Application.

b. Explain how the reliability benefits identified in part (a) were considered in determining that the proposed project is prudent and represents the least-cost solution.

Response:

a. Refer to the response to IR-49(b).

The addition of 100 MW of on-Island capacity provided by the ProEnergy Opportunity has an ELCC (i.e., perfect capacity value) of approximately 75 MW,[235] which is not sufficient to meet the industry standard LOLE target of 0.1 days per year. The E3 Study did not evaluate the specific scenario of adding the ProEnergy Opportunity together with the incremental 15 MW of firm capacity identified by NBEM. Accordingly, a specific 2030 LOLE result is not available for that scenario. However, the addition of approximately 90 MW of perfect capacity would improve reliability relative to the no-additional-capacity case (24 days per year) but would not achieve the industry standard LOLE target of 0.1 days per year, indicating that additional capacity is required.

TABLE IR-86
E3 Loss of Load Expectation Results

Nameplate Capacity Added by 2030	Perfect Capacity (i.e., ELCC) added by 2030	2030 Loss of Load Expectation (LOLE)
0 MW	0 MW	24 days per year
15 MW additional from NBEM[236] 100 MW ProEnergy Opportunity	15 MW + 75 MW = 90 MW	0.1 to 24 days per year
Varies by Portfolio	115 MW	0.1 days per year

b. Refer to the responses to IR-23(a) and IR-86(a).

[235] IR-23 – Attachment 1 - E3 Study, Figure 5-9 (page 52), 50 MW thermal units (i.e., ProEnergy Opportunity CTs) have an ELCC of 75 per cent.
[236] Refer to the response to IR-46(a).

The Portfolio NPV Study provides a comprehensive NPV analysis that compares the present value costs of several resource portfolio options. The results of the Portfolio NPV Study demonstrate that "Portfolios 2 and 3, which are anchored by the ProEnergy Opportunity, consistently had the lowest present value cost under all sensitivity tests."[237] The Portfolio NPV Study provides strong justification to pursue the ProEnergy Opportunity, on the basis that it forms part of the least-cost solution to address Maritime Electric's total capacity needs by 2030.

[237] IR-54 – Attachment 1 - Portfolio NPV Study, Section 6.0, page 30.

IR-87 The Net Present Value analysis filed in response to IR-16 includes avoided costs associated with the purchase of off-Island firm capacity.

a. Explain how the avoided off-Island capacity costs were determined.

b. Identify and explain the circumstances that could cause the avoided off-Island capacity costs to differ materially from those assumed in the Application.

c. Explain whether the Net Present Value analysis and the Impact on Rate Base, Revenue Requirement and Customer Rates analyses would change if the avoided off-Island capacity costs differ from those assumed in the Application.

d. If yes, update the analyses assuming the avoided off-Island capacity costs are:

i. 10% lower;
ii. 25% lower; and
iii. 50% lower than assumed in the Application.

Response:

a. The NPV analysis filed in Maritime Electric's response to IR-16 from Commission Staff[238] used the same approach that was explained in Maritime Electric's response to IR-2(e) from Synapse.[239]

The NPV analysis in IR-16 included avoided capacity pricing from 2027 to 2030, based on indicative capacity pricing from NBEM. The specific avoided capacity cost inputs are shown in the IR-16 – Updated Supplemental Filing Confidential Appendix B Avoided Capacity and Ancillary Service Costs Inputs table.[240]

b. Avoided off-Island capacity costs are based on indicative pricing for firm capacity purchased from NB Power, as described in the response to IR-87(a). As noted in the response to IR-46(b), updated indicative pricing provided by NBEM is already higher than the values previously assumed in the Company's previously filed NPV analyses, demonstrating that these costs are subject to change over time.

The cost of off-Island capacity is influenced by regional supply and demand conditions for firm capacity resources. In periods where regional capacity is limited and demand for capacity is high, capacity pricing increases. Conversely, in periods where surplus capacity exists, pricing is expected to decline.

Historically, when system peaks in PEI and NB were not closely aligned, NB Power had surplus capacity available during periods when PEI was approaching peak demand. In those circumstances, the availability of excess capacity contributed to more favourable pricing for off-Island purchases. However, as system peaks in PEI have become more

238 Exhibit M-29, page 1.
239 Exhibit M-6, page 4.
240 IR-16 – Updated Supplemental Filing Confidential Appendix B, Avoided Capacity and Ancillary Service Costs Inputs table (page 5), rows 3 (Year 3) through 6 (Year 6).

closely aligned with those in NB, and as regional reserve margins have declined, surplus capacity available for export has diminished significantly, and similar pricing availability cannot be expected under current system conditions.

The Company notes that the region is currently experiencing, and is forecast to continue experiencing, capacity constraints until new resources are brought into service. In such conditions, the cost of capacity available for purchase would reasonably be expected to reflect the cost of new capacity development within the region, with potential for higher pricing in periods of scarcity where multiple parties are seeking access to limited capacity resources.

Accordingly, the avoided off-Island capacity costs assumed in Maritime Electric's response to IR-16 from Commission Staff[241] could differ materially from actual costs if regional supply and demand conditions evolve, including changes in the timing and cost of new capacity additions, the availability of surplus capacity, or the level of competition for available capacity resources.

c. The NPV analysis and Estimated Impact on Rate Base, Revenue Requirement and Customer Rates calculations filed in Maritime Electric's response to IR-16 from Commission Staff would change if avoided off-Island capacity costs differ from those assumed.[242]

In that NPV analysis, avoided off-Island capacity costs were modelled as a value (i.e., savings) associated with the ProEnergy Opportunity. If the assumed avoided off-Island capacity costs decrease, the value of on-Island capacity resources would decrease. If the assumed avoided off-Island capacity costs increase, the value of on-Island capacity resources would increase.

In the Estimated Impact on Rate Base, Revenue Requirement and Customer Rates calculations, avoided off-Island capacity costs were modelled as an annual cost savings. The revenue requirement associated with the ProEnergy Opportunity is not affected by changes in assumed off-Island capacity costs. However, changes in the assumed cost of off-Island capacity affect the customer rates that would otherwise be incurred if the Company continued to rely on capacity purchases rather than proceeding with the ProEnergy Opportunity. As a result, higher assumed off-Island capacity costs reduce the incremental customer rate impact of the ProEnergy Opportunity, while lower assumed off-Island capacity costs increase the incremental customer rate impact of the ProEnergy Opportunity.

The updated Portfolio NPV Study, provided as IR-54 - Attachment 1, did not include off-Island capacity purchases because the purpose of the Portfolio NPV Study was to compare the cost of various resource portfolio options with each other. The Portfolio NPV Study explains that "the five portfolio options presented in the E3 Study have the same total ELCC, therefore, avoided capacity purchases from the development of any of the five portfolios will be equal."[243]

241 Exhibit M-29, page 1.
242 Exhibit M-29, page 1.
243 IR-54 – Attachment 1 - Portfolio NPV Study, Section 3.6, page 12.

d. Refer to the NPV analysis Summary Table in IR-16 – Updated Supplemental Filing Confidential Appendix B, provided in Maritime Electric's response to IR-16 from Commission Staff.[244] In the Summary Table, the line item "Off-Island Firm Capacity" represents the present value of avoided off-Island firm capacity purchases. Table IR-87(d)(i) provides the NPV results with avoided off-Island capacity cost scenarios of 10 per cent lower, 25 per cent lower and 50 per cent lower than the avoided costs included in the response to IR-16.

TABLE IR-87(d)(i)
ProEnergy Opportunity NPV Analysis Results with Various Avoided Off-Island Firm Capacity Cost Scenarios
Present Value (2024 $ x 1,000)

	IR-16 (as filed)	Avoided Off-Island Firm Capacity Cost Scenarios		
		10% lower	25% lower	50% lower
Nominal Capacity (MW)	100	100	100	100
Useful Life	50	50	50	50
Total Installed Cost ($ x 1,000)	353,372	353,372	353,372	353,372
Annual Fixed O&M in Year 1 ($ x 1,000)	1,197	1,197	1,197	1,197
Project Cost				
Amortization	116,422	116,422	116,422	116,422
Operating and Maintenance	24,364	24,364	24,364	24,364
Debt Interest	103,229	103,229	103,229	103,229
Equity Return	131,052	131,052	131,052	131,052
Income Taxes	58,878	58,878	58,878	58,878
Total Project Cost	433,945	433,945	433,945	433,945
Avoided Cost				
Off-Island Firm Capacity	858,238	772,414	643,678	429,119
Off-Island Load Following	0	0	0	0
Off-Island Spinning Reserve	0	0	0	0
Standalone Synchronous Condenser	45,813	45,813	45,813	45,813
Total Avoided Cost	904,051	818,227	689,491	474,932
Net Present Value	**470,106**	**384,282**	**255,546**	**40,987**
% Savings	***52%***	***47%***	***37%***	***9%***

Refer to the response to IR-84 regarding updates to the estimated impact on customer rates.

A comparison of the rate impacts provided in Maritime Electric's response to IR-16 from Commission Staff,[245] the updated rate impact reflecting updated pricing from NBEM and

[244] Exhibit M-29, IR-16 – Updated Supplemental Filing Confidential Appendix B, Summary Table (page 7).
[245] Exhibit M-29, page 1.

an ELCC of 75 MW for the ProEnergy Opportunity, and the rate impacts requested in IR-87(d)(ii) with avoided capacity costs 10 per cent, 25 per cent and 50 per cent lower is provided in Table IR-87.

TABLE IR-87(d)(ii)
ProEnergy Opportunity Updated Estimated Impact on Customer Rates by Rate Class

Customer Class	Exhibit M-29 Response to IR-16	IR-87(d) Rate Impacts with Updated NBEM Pricing and 75 MW ELCC			
		Updated Rate Impacts	IR-87(d)(i) Avoided Capacity Costs 10% Lower	IR-87(d)(ii) Avoided Capacity Costs 25% Lower	IR-87(d)(iii) Avoided Capacity Costs 50% Lower
Rural Residential	6.25%	5.18%	5.65%	6.36%	7.54%
Urban Residential	6.36%	5.27%	5.75%	6.47%	7.67%
General Service	6.13%	5.08%	5.54%	6.24%	7.40%

An updated estimated impact on customer rates, based on avoided off-Island capacity costs being ten per cent lower, is provided as IR-87(d) - Confidential Attachment 1. The estimated increase is approximately 5.50 to 5.75 per cent for benchmark Rural Residential, Urban Residential and General Service customers.[246]

An updated estimated impact on customer rates, based on avoided off-Island capacity costs being 25 per cent lower, is provided as IR-87(d) - Confidential Attachment 2. The estimated increase is approximately 6.25 to 6.50 per cent for benchmark Rural Residential, Urban Residential and General Service customers.

An updated estimated impact on customer rates, based on avoided off-Island capacity costs being 50 per cent lower, is provided as IR-87(d) - Confidential Attachment 3. The estimated increase is approximately 7.5 per cent for benchmark Rural Residential, Urban Residential and General Service customers.

[246] Benchmark Residential Rural and Residential Urban customers include 650 kWh of consumption per month. Benchmark General Service customers include 10,000 kWh of consumption per month. Taxes are excluded from the impact on customer rates.

IR-88 Does Maritime Electric have corporate performance targets or objectives? If yes, provide the corporate performance targets or objectives applicable from 2024 to the present and explain how they relate to the proposed project, if at all.

Response:

THE RESPONSE TO IR-88 HAS BEEN FILED
WITH THE COMMISSION ON A CONFIDENTIAL BASIS.

IR-89 Does Maritime Electric maintain personal performance targets, corporate performance targets, or incentive plans applicable to employees? If yes, provide the applicable targets, objectives and incentive measures for employees to participate in an incentive compensation plan from 2024 to the present.

Response:

THE RESPONSE TO IR-89 HAS BEEN FILED
WITH THE COMMISSION ON A CONFIDENTIAL BASIS.

IR-90 Will approval or denial of this Application affect the compensation, incentive compensation, bonus, or other financial remuneration of any Maritime Electric employee? If yes explain how the employee's compensation would be affected, quantify the financial impact (if possible), and explain whether such compensation is proposed to be recovered through customer rates.

Response:

THE RESPONSE TO IR-90 HAS BEEN FILED
WITH THE COMMISSION ON A CONFIDENTIAL BASIS.

IR-91 Will approval or denial of this Application affect the financial return or other financial benefit received by Maritime Electric's shareholder? If yes, explain how the shareholder's financial return or benefit would be affected, quantify the financial impact (if possible), and explain whether the financial benefit is proposed to be recovered through customer rates.

Response:

No, approval of the Supplemental Filing would not provide Maritime Electric's shareholder with any special, incremental, or discretionary financial benefit. The only shareholder-related financial effect would be the ordinary opportunity to earn the Commission-approved fair return on the equity-financed portion of the prudent utility investment that is approved for inclusion in rate base. This treatment is consistent with normal cost-of-service ratemaking and with the Fair Return Standard, which recognizes that a regulated utility must be provided with a reasonable opportunity to earn a return that is commensurate with investments of comparable risk, sufficient to maintain financial integrity, and adequate to attract capital on reasonable terms.

IR-23 – Attachment 1

2026 Maritime Electric Resource Adequacy Study

Maritime Electric Resource Adequacy Study

Determining 2030 System Needs and Evaluating Effective Load Carrying Capability

July 2026

Energy+Environmental Economics

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Acronym Definitions

Acronym	Definition
CT	Combustion Turbine
DR	Demand Response
ELCC	Effective Load Carrying Capability
ELR	Energy Limited Resource
EPA	Energy Purchase Agreement
EPRI	Electric Power Research Institute
EUE	Expected Unserved Energy
ICAP	Installed Capacity
IESO	Independent Electricity System Operator
IRAC	Island Regulatory and Appeals Commission
IRP	Integrated Resource Plan
ISO	Independent System Operator
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
MARS	Multi-Area Reliability Simulation
Maritime Electric	Maritime Electric Company, Limited
MISO	Midcontinent Independent System Operator
MW	Megawatt
NBEM	New Brunswick Energy Marketing Corporation
NB Power	New Brunswick Power Corporation
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
OATT	Open Access Transmission Tariff
PCAP	Perfect Capacity
PEI	Prince Edward Island
PJM	PJM Interconnection LLC
Point Lepreau	Point Lepreau Nuclear Generating Station
PRM	Planning Reserve Margin
PV	Photovoltaic
QCC	Qualifying Capacity Credits
RA	Resource Adequacy
RECAP	Renewable Energy Capacity Planning Model: E3's LOLP Modeling Software
RICE	Reciprocating Internal Combustion Engine
SERVM	Strategic Energy & Risk Valuation Model
TRN	Total Reliability Need
UCAP	Unforced Capacity

Executive Summary

Maritime Electric Company, Limited ("Maritime Electric") is experiencing sustained load growth, driven by population growth and the continued adoption of electric space heating, requiring new generation capacity to maintain reliability. Several features of the Maritime Electric system shape its resource adequacy needs: a resource mix that is increasingly weather-dependent, a substantial reliance on off-Island capacity delivered over the subsea cables between New Brunswick and Prince Edward Island, and exposure to the loss of generators that are large relative to the size of the Maritime Electric system. Additionally, as electrified heating brings Maritime Electric's winter peak into closer coincidence with the regional winter peak, and as reserve margins across the region tighten, the surplus regional capacity that the utility has historically drawn on during peak periods is less likely to be available.

Maritime Electric retained Energy and Environmental Economics ("E3") to perform a resource adequacy study of its power system in support of its On-Island Capacity for Security of Supply Project application before the Island Regulatory and Appeals Commission ("IRAC"), Docket UE20742. The study calculates Maritime Electric's Total Reliability Need ("TRN") and planning reserve margin ("PRM") required to meet a loss of load expectation ("LOLE") standard of 0.1 days per year (the regional reliability target established by the Northeast Power Coordinating Council ("NPCC")), and the contribution of the utility's existing and potential new resources toward meeting those needs, i.e., their effective load carrying capability ("ELCC"). This analysis provides critical inputs to the planning processes that enable Maritime Electric to identify a least-cost, reliable portfolio of resources.

Study Questions

This study assesses Maritime Electric's system using E3's Renewable Energy Capacity Planning ("RECAP") model, a loss-of-load-probability model developed by E3 that is used to evaluate the resource adequacy needs. RECAP is designed to address the needs of a changing electricity sector by incorporating the unique characteristics of variable and dispatch-limited resources into the traditional reliability framework. The outputs of RECAP have been relied upon for regulatory proceedings across the North American continent, including many proceedings in the Atlantic provinces.[1]

Specifically, this study analyzed three key questions:

1. **How much capacity does Maritime Electric need to meet its resource adequacy standard by 2030?**
2. **How effective are Maritime Electric's existing and potential new resources at providing capacity, both individually and in combination?**

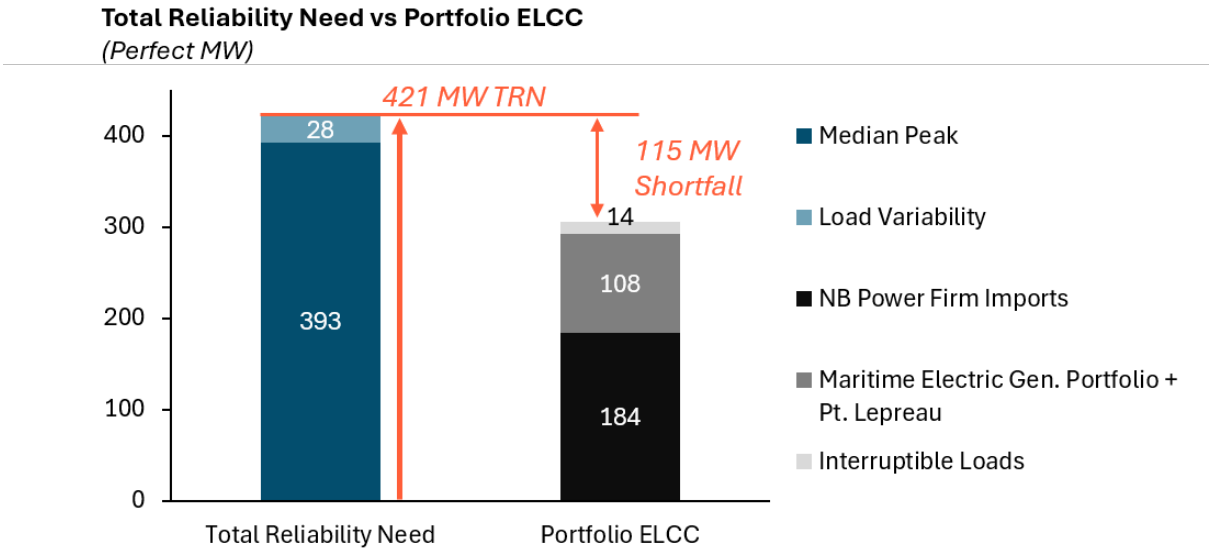
[1] See Appendix A for detailed Jurisdictional Review of Resource Adequacy Practices across North America

3. What are the periods of greatest reliability risk for Maritime Electric in the near term, given new load growth and new customer demand?

Key Findings

Maritime Electric faces an approximately 115-megawatt (MW) capacity shortfall by 2030. Maritime Electric's Total Reliability Need ("TRN") to meet the 0.1 LOLE standard in 2030 is 421 MW of perfect capacity, equivalent to a planning reserve margin of 7.1% under the "perfect capacity" ("PCAP") accounting framework used throughout this study. This is equivalent to an 18.5% PRM using Maritime Electric's prior installed-capacity ("ICAP") accounting.[2] Existing resources and firm contracts provide 306 MW of equivalent perfect capacity, leaving a shortfall of 115 MW as shown in Figure ES-1. Absent additional resources, in 2030 the system will be exposed to loss-of-load events as frequently as 24 days per year, with individual events ranging from 1 hour to over 24 hours in duration.

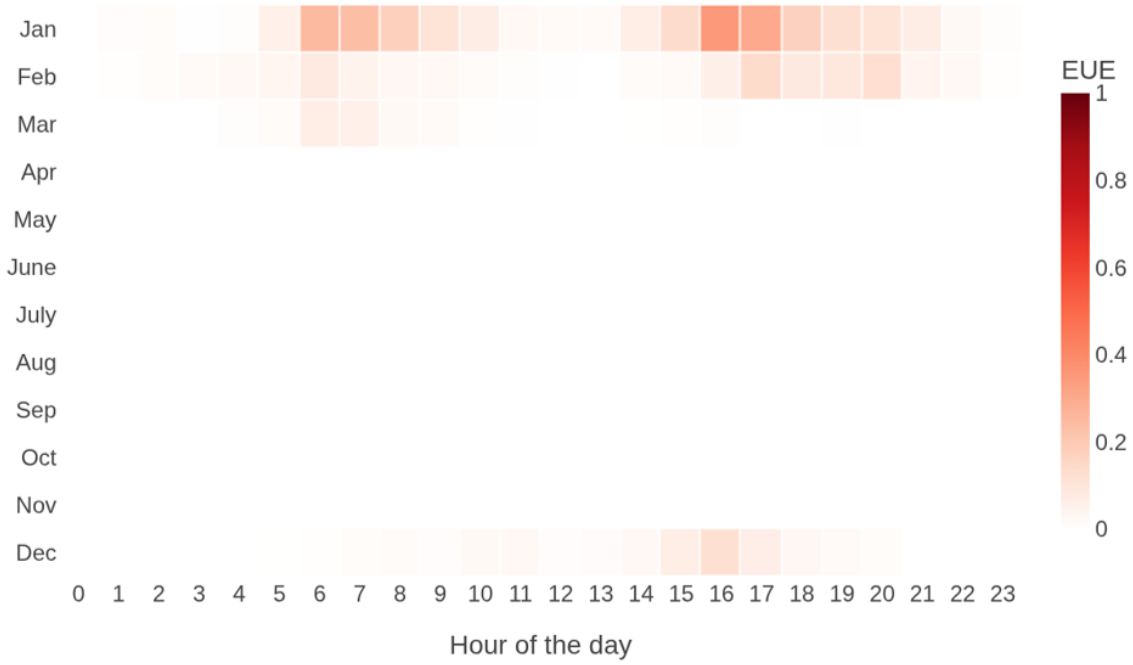
Figure ES-1. By 2030, Maritime Electric faces a resource shortfall of 115 MW



Reliability risk is concentrated in winter mornings and evenings. Risk is greatest at these times but can extend across full days during cold snaps. It reflects the coincidence of three factors: (1) very cold conditions that can simultaneously reduce wind output and increase heating demand, (2) limited energy available for import during these same hours due to increasingly coincident peaks across the region, and (3) the disproportionate effect of a single large-unit outage on a small island system. Risk is concentrated in early mornings and late afternoons/early evenings in winter months when the system is exposed to challenging cold weather conditions and/or unit outages.

[2] Perfect capacity (PCAP) is the amount of a hypothetical, perfectly reliable resource — one available 100% of the time with no outages — that a given set of resources is equivalent to for reliability purposes, i.e., installed capacity derated by each resource's reliability contribution (ELCC).

Figure ES-2. Hours with Highest Loss-of-Load Risk in 2030



The capacity value of candidate on-Island resources varies by technology and penetration, and thus meeting Maritime Electric's capacity shortfall likely requires a portfolio of resource options:

- **Incremental wind generation** provides limited capacity value, with marginal ELCC in the single digits, reflecting Maritime Electric's existing purchases of 120 MW of wind and the resulting concentration of remaining reliability risk in periods where wind generation is low.
- **Solar generation** has very low capacity value because reliability events are concentrated primarily before sunrise and after sunset during very cold winter days with limited sunlight hours.
- **Energy-limited resources** such as 4-hour and 8-hour storage are effective at low penetration (67% and 81% ELCC respectively, for the first 20 MW) but, as shown in Figure ES-3, their reliability contribution drops as more batteries flatten the peak and spread reliability risk across a longer window of hours. Initial tranches (incremental blocks of capacity additions) of demand response can reach as high as 94% ELCC when its call duration and frequency are matched to the system's needs, but also face similar saturation effects that are more pronounced at higher penetrations of battery storage.
- **Thermal generation has the highest capacity accreditation, though unit size affects its effective capacity value.** Unlike variable and energy limited resources, thermal capacity does not exhibit saturation as shown in Figure ES-4, because it can dispatch whenever needed and for as long as needed. However, thermal generators are subject to unplanned outages, and the reliability risk created by these outages is more significant for larger units. A 20 MW unit with a 5% forced outage rate provides around 17.2 MW of effective capacity (86% ELCC) while a larger 50 MW unit with a 5% forced outage rate provides around 37.5 MW

of effective capacity (75% ELCC). This difference is observed because a single large outage on a relatively small system is itself a significant driver of reliability risk. Smaller units therefore provide a more reliable contribution to critical reliability periods.

Figure ES-3. Cumulative and Marginal ELCC of Storage

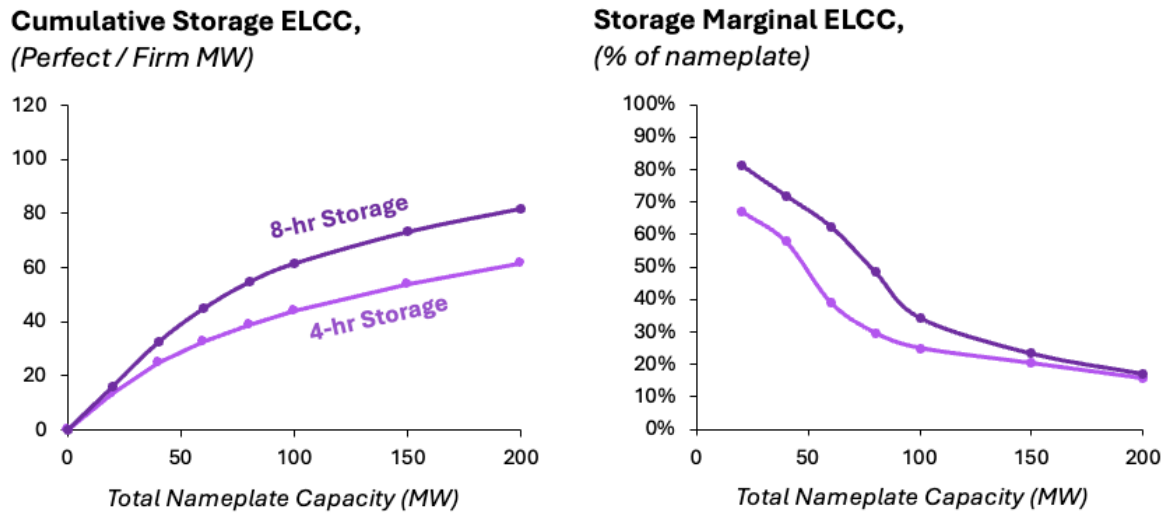
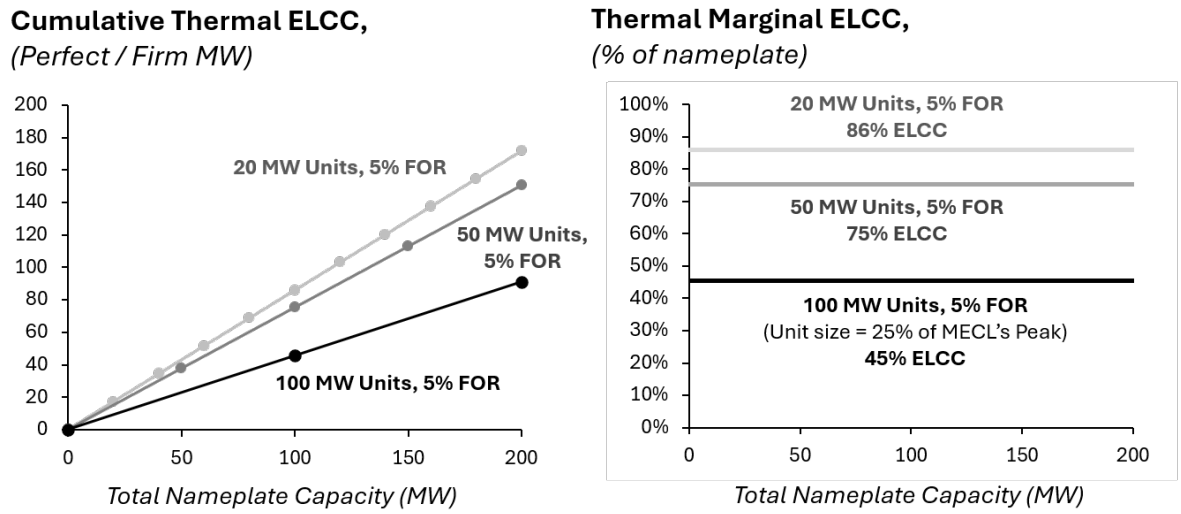


Figure ES-4. Cumulative and Marginal ELCC of New Thermal Units of Different Sizes



Available New Brunswick intertie headroom above existing firm contracts is limited, and its reliability value is declining as regional peaks become more coincident. Of Maritime Electric's 270 MW of intertie rights, 220 MW is committed to firm resources (its share of the Point Lepreau Nuclear Generating Station ("Point Lepreau") operated by the New Brunswick Power Corporation ("New Brunswick Power") and contracted firm imports New Brunswick Energy Marketing Corporation ("NBEM") capacity), leaving approximately 50 MW of headroom. Non-firm, as-available energy purchases that use this headroom are less likely to be available in the future because the same conditions that drive reliability challenges for Maritime Electric increasingly drive coincident

capacity challenges for New Brunswick and the broader region. Cold snaps that elevate electric heating load can also reduce wind output and impact the whole region. Outages of firm generators such as Point Lepreau in New Brunswick can create widespread regional challenges. Even though Maritime Electric might be able to procure non-firm energy imports during a critical reliability period unique to its system, such as when on-Island generators suffer outages or local wind generation falls, Maritime Electric cannot rely on non-firm imports in lieu of accredited capacity resources during cold weather events that impact the entire region.

Taken together, these findings indicate that a portfolio of resources that includes thermal generation is needed to efficiently close Maritime Electric's capacity gap; meeting the need cost-effectively will require a portfolio that balances each resource's capacity contribution against its investment and operating costs. The results also indicate significant resilience concerns that go beyond traditional resource adequacy accounting: given the system's reliance on the subsea cables to New Brunswick and its exposure to large unit outages, Maritime Electric and Prince Edward Island face both reliability and resilience considerations driven by extreme cold winter conditions that growing winter heating demand will exacerbate.

This study assumes 100% availability of the subsea cables connecting PEI to the mainland. The loss of one or more of the cables would create a very significant reliability challenge for Maritime Electric, however, given both the magnitude of the potential impact and the lack of sufficient data to develop a robust statistical estimate of the likelihood of a cable outage, E3 recommends that Maritime Electric conduct a supplementary "resilience" analysis. The analysis would simulate the performance of Maritime Electric's system during an extended cable outage, with the aim of identifying whether additional on-Island thermal generation might be needed to ensure acceptable system performance during such an event.

Based on the findings of this study, E3 recommends the following actions for Maritime Electric:

1. **Accelerate procurement of new resources to close the resource adequacy gap, prioritizing resources with high capacity value**

Maritime Electric has an urgent need for new resources. Absent additional resources, Maritime Electric's system would be exposed to an average of 24 loss-of-load events per year by 2030. With long lead-times for procurement, permitting, construction, and interconnection of new resources, immediate action will be needed to ensure Maritime Electric can continue to meet NPCC standards for resource adequacy. Given the size and urgency of the need, Maritime Electric should prioritize resources with relatively high capacity value. Thermal firm resources provide the highest capacity value solutions, both anchoring near-term reliability and unlocking the reliability contribution of the wind, solar, and storage resources that can be procured alongside it.

2. **Use the results from this study to inform least-cost and reliable portfolios in future economic analyses**

As the utility considers procuring new resources to meet near-term reliability needs, E3 recommends that Maritime Electric perform an economic analysis on potential portfolios that account for both the portfolio's capital cost, annual costs, and ability to meet the 115 MW shortfall

by 2030. The evaluations can identify the most cost-effective way to meet Maritime Electric's reliability needs.

3. Evaluate whether additional on-Island capacity is needed for resilience

While not needed for near-term procurement decisions, Maritime Electric's planners should consider the value of existing and new resources in preparing for resilience events such as a full grid disconnection from New Brunswick. Maritime Electric should ensure it has sufficient resources to anticipate, respond to, and recover from unpredictable events and systemic shocks to the electricity system, including extreme weather events. This is especially important as customers increasingly rely on electricity for space heating during extreme cold snaps, increasing the potential consequences of a resilience event.

1. Introduction

Maritime Electric Company Limited ("Maritime Electric") retained Energy and Environmental Economics ("E3") to perform a comprehensive resource adequacy study of its power system. The study and its values are performed within the context of Maritime Electric's On-Island Capacity for Security of Supply Project application before the Island Regulatory and Appeals Commission ("IRAC"), Docket UE20742.

"Resource adequacy" ("RA") refers to the ability of an electric power system to serve load across a broad range of weather and system operating conditions, and to attain an acceptably low frequency of power supply shortfall or "loss-of-load" events. The resource adequacy of a system depends on characteristics of its load (e.g. seasonal patterns, weather sensitivity, hourly patterns) and resources (e.g. size, dispatchability, outage rates, variability). Meeting a resource adequacy standard is critical for health, safety and economic well-being; however, it is a challenge that is increasing in complexity as the resource mix changes and the frequency and severity of extreme weather increases. Maritime Electric manages a portfolio of generating resources that, in aggregate, is intended to meet those resource adequacy needs.

Maritime Electric's resource portfolio, similar to those of other utilities, comprises six types of resources:

- **"Firm resources"** (e.g. fuel oil, gas, nuclear), which are generally capable of supplying a stable and consistent level of power to the electricity system when needed, except when impacted by unexpected plant outages or insufficient fuel supply;
- **"Variable resources"** (e.g. distributed solar, utility solar, wind), whose availability varies from one hour to the next, typically due to a combination of meteorological factors;
- **"Energy-limited resources"** (e.g. energy storage, hydroelectric power with reservoir storage, thermal generators with run-time limitations), whose availability to operate continuously over sustained periods is limited by the availability of stored energy or other factors;
- **"Demand-side resources"** (e.g. demand response), whose availability varies based on the specific characteristics of the program design such as seasonal availability, time of day, limits on dispatch frequency, and other factors.
- **"Firm imports"** representing firm capacity-backed energy procured from outside the system, delivered over tie-lines, that is not unit-contingent.
- **"Non-firm imports"** representing the procurement of as-available energy from outside the system, delivered over tie-lines.

These categories are descriptive of the nature of each resource type; however, each can contribute toward meeting reliability needs in its own way. This study uses industry best practices including loss of load probability ("LOLP") modeling to evaluate Maritime Electric's resource adequacy needs and the contributions of its available resources toward meeting those needs. It does so by

calculating the following parameters that are critical inputs to Maritime Electric's resource planning and procurement processes:

- The **"Total Reliability Need" ("TRN"),** the total quantity of "perfect" capacity – a theoretical generating resource that can turn on whenever needed and run for as long as needed without interruption – needed to maintain a standard for **loss of load expectation ("LOLE")** of 0.1 days per year (or "one day in ten years"), established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Corporation ("NERC") as the regional reliability target.
- The **Planning Reserve Margin ("PRM"),** calculated as the TRN minus the median or "1-in-2" peak load, divided by the median peak load.[3]
- **Effective load carrying capability ("ELCC")** values to characterize the ability of existing and candidate resources to contribute to meeting supply needs. Under emerging best practices, described in more detail below and in the E3 whitepaper attached in Appendix B, each resource type is "accredited" using the ELCC approach, providing an accurate measure of its ability to help avoid loss-of-load events and creating a level playing field across resource types.

1.1 Study Motivation

Maritime Electric is experiencing significant load growth due to population growth and continued adoption of electric home heating; meeting future customer electric demand will therefore require new capacity to maintain electric reliability. As part of meeting this increasing customer demand, Maritime Electric is proposing the development of additional thermal generation to provide capacity during critical reliability periods.

Maritime Electric provides retail electricity service to approximately 90% of residents on Prince Edward Island ("PEI") from a portfolio of on- and off-Island resources. On-Island resources include a mixture of PEI wind, solar, and thermal (oil-fired) generation. Off-Island resources include a participation share of the Point Lepreau Nuclear Generating Station ("Point Lepreau") in Maces Bay, New Brunswick, operated by the New Brunswick Power Corporation ("New Brunswick Power"), and contracted firm capacity purchases through an Energy Purchase Agreement ("EPA") with New Brunswick Energy Marketing Corporation ("NBEM").

To calculate the TRN, target PRM, and ELCC values described above, E3 uses our in-house Renewable Energy Capacity Planning ("RECAP") model. RECAP is a loss-of-load-probability model developed by E3 that has been used by utilities to evaluate resource adequacy of electric systems across the North American continent, including in Nova Scotia, New Brunswick, Newfoundland, the Yukon Territory, Florida, Texas, New Mexico, Washington, Montana, California, and others. RECAP is

[3] Maritime Electric's equivalent to a "1-in-2" peak load is a "50/50" peak load.

designed to address the needs of a changing electricity sector by incorporating the unique characteristics of variable and dispatch-limited resources into the reliability framework.

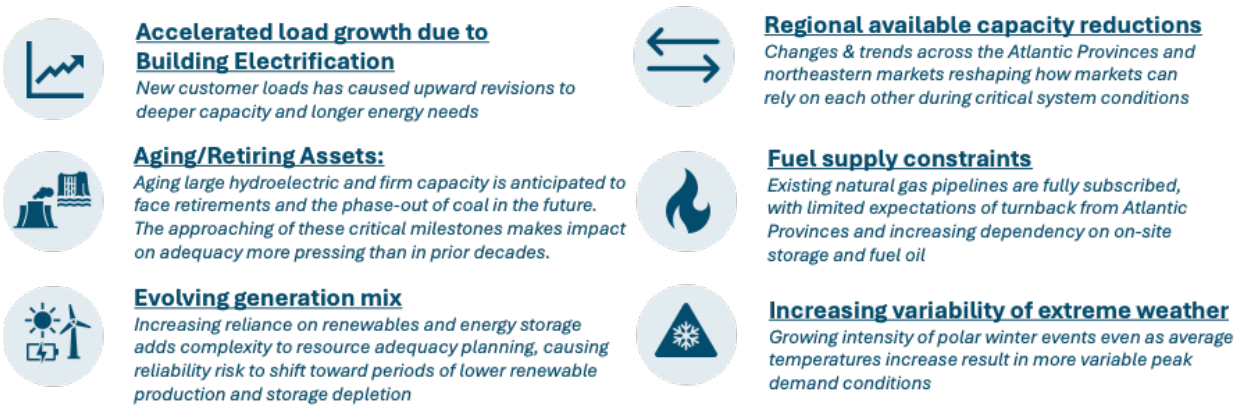
This study analyzed the following three questions:

1. **How much capacity does Maritime Electric need to meet its resource adequacy standard by 2030?**
2. **How effective are Maritime Electric's existing and potential new resources at providing capacity, both individually and in combination?**
3. **What are the periods of greatest reliability risk for Maritime Electric in the near term, given new load growth and new customer demand?**

1.2 Current and Emerging Challenges in Resource Adequacy in the Northeast US and Canada

In the last decade, the increased frequency and severity of extreme weather events across North America have underscored the importance of ensuring that planning assumptions accurately characterize reliability risk. In 2021, Winter Storm Uri caused widespread loss-of-load across Texas, resulting in significant health and safety impacts including loss of life. In the Northeast, the 2023 Polar Vortex and 2026 Winter Storm Fern events created challenges for system operators. In New England, many thermal electric generators switched to fuel oil due to competing demand for natural gas from heating demand. These dual-fuel oil units provide capacity important for reliability, but their availability depends on fuel procurement decisions made months in advance and storage logistics that add cost and complexity. Wind generation, though variable, provided needed power during these multi-day events. The complexity of these weather-driven dynamics makes comprehensive resource adequacy planning vital to ensure reliable electric service.

Figure 1-1. Current and Emerging RA Challenges in the Northeast US and Canada



In addition to the increased weather risk, the Canadian and US Northeast electric systems are undergoing a transformation of both loads and resources, summarized in Figure 1-1. Load growth

driven by electrification and population growth combined with the retirements of aging firm and hydro generation are driving the need for new resources. The addition of renewables and energy storage resources adds complexity to resource adequacy need determination and resource accreditation. As electrified heating adoption increases across the region, peak demand periods will be associated with the coldest weather conditions and will be more coincident across jurisdictions. These factors mean that neighboring regions face tighter margins and may not be able to rely as much on each other for non-firm imports during peak periods as they have in the past.

1.3 Regional Planning Context

The changes affecting Maritime Electric's reliability align with those affecting the region as a whole. Load growth, electrification of space heating, and continued build-out of renewables increase the weather dependency of net load[4] that must be met by firm and other available resources. Accurately characterizing the ability of a portfolio of resources to meet load reliably requires modeling that can account for a wide variety of weather and load conditions.

To account for these challenging conditions, utilities in the Northeast region and beyond have increasingly moved to probabilistic methodologies for resource adequacy planning. This study uses industry best practices that are aligned with practices that have been adopted across the region; see Appendix A for a detailed jurisdictional review. These practices include:

- The use of a **probabilistic reliability standard**. The most common standard is to plan for loss-of-load events to occur no more frequently than once every ten years (LOLE of no more than one day per ten years or 0.1 days per year).
- The use of **probabilistic models** such as RECAP to determine total reliability need, establish an appropriate PRM, and accredit the contribution of their resources towards that need.
- The use of the **ELCC methodology** to measure the reliability contribution of individual resources towards the PRM in a way that is responsive towards the complexity of the evolving grid. It is widely used to measure the reliability contribution of renewables and increasingly applied to other resources such as hydro, energy storage and thermal generation.

1.4 Report Overview

The remainder of this report is organized into the following sections:

- **Section 2** introduces resource adequacy and the current and emerging RA planning challenges for Northeastern US, Canada, and Maritime Electric.
- **Section 3** details the model and the methodology used in this study, using the best practices for modern RA planning approaches.

[4] Net load is load minus renewables generation.

- **Section 4** describes in detail the inputs and assumptions used to represent Maritime Electric's specific system.
- **Section 5** presents the results of this Maritime Electric-specific RA study.
- **Section 6** presents key takeaways and conclusions based on this study's results.
- **Appendix A** provides a jurisdictional scan of regional RA planning practices.
- **Appendix B** describes the methodology that E3 employs in resource adequacy studies, including this one.
- **Appendix C** provides further detail on selected portions of the methodology specific to Maritime Electric.

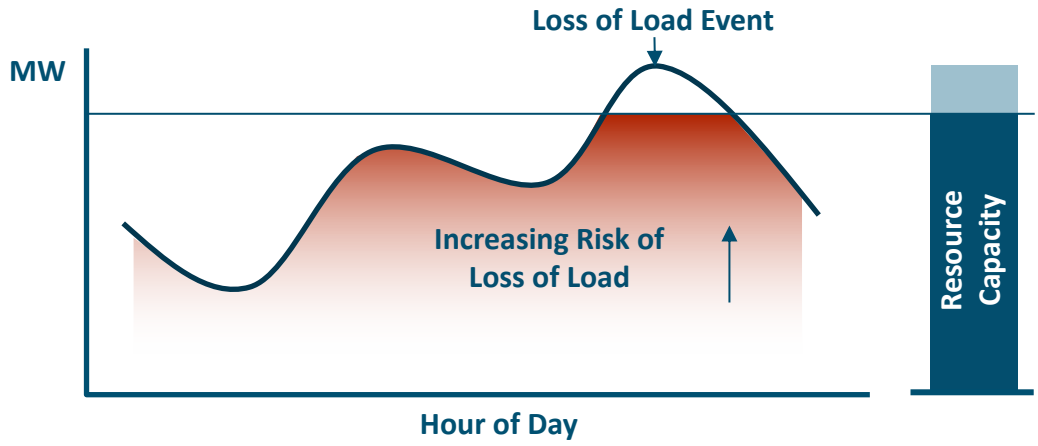
2. Resource Adequacy for Maritime Electric

"Resource adequacy" is the ability of an electric power system to provide sufficient generation to meet loads across a broad range of weather and system operating conditions, subject to a long-run reliability standard that establishes the acceptable frequency of loss-of-load events[5]. The resource adequacy of a system depends on the characteristics of its load, including seasonal patterns, weather sensitivity, and hourly patterns, as well as the characteristics of its supply-side resources including size, dispatchability, outage rates, and other factors that may limit their availability during critical periods. Ensuring resource adequacy is an important goal for utilities seeking to provide reliable service to their customers and focuses on having sufficient generation to meet demand and avoid Loss of Load Events as illustrated in Figure 2-1. Other aspects of providing reliable service, like distribution system maintenance and resilience, are also important but are outside the scope of this report.

NERC Definition of Resource Adequacy

"The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."

Figure 2-1. Illustration of a Loss of Load Event Due to Insufficient Generation



2.1 Maritime Electric-Specific Current and Emerging RA Challenges

While Maritime Electric faces resource adequacy challenges that are similar to those of other utilities, such as meeting increased demand for electricity and accurately characterizing the ability of its thermal and variable resources toward meeting its resource adequacy needs, it faces additional challenges due to its small size and geographic isolation. In particular, Maritime Electric's dependence on off-Island resources, lack of regional load diversity, and susceptibility to large

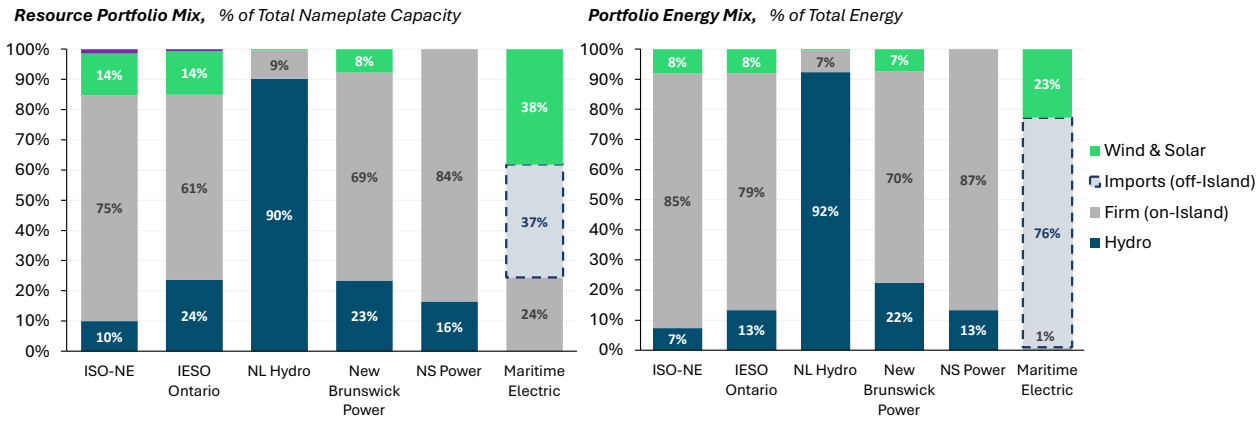
[5] NERC Glossary of terms: https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf

generator and transmission outages relative to the size of Maritime Electric's system create significant reliability challenges.

Most of Maritime Electric's firm capacity comes from off-Island imports. Prince Edward Island is connected to the mainland by four subsea cables with a combined interconnection rating of 300 megawatts ("MW")[i6], out of which 270 MW are accessible by Maritime Electric through agreements with New Brunswick Power.[7] This enables Maritime Electric to access its 30 MW participation share of Point Lepreau as well as the capacity contracted with NBEM through its EPA, of which 190 MW is contracted as firm. The remaining 50 MW of capacity can be used for importing non-firm energy, available depending on surplus capacity in the region.

The remaining resources meeting customer demand are located on PEI. Maritime Electric's on-Island resources consist of a mixture of thermal, wind, and solar resources. As seen in Figure 2-2, unlike neighboring systems, wind and solar make up two-thirds of on-system installed capacity. More than one-third of Maritime Electric's total energy needs are met by wind and solar, while imports from New Brunswick account for half of total energy needs. The high proportion of variable renewables makes Maritime Electric's portfolio more weather-dependent than any of its neighbors in the Canadian and US Northeast region. The variability in wind and solar generation in PEI, and its relationship to periods of high load, shapes the critical periods for reliability risk that are examined in this study.

Figure 2-2. Comparison of Resource and Portfolio & Energy Mix across Northeast Systems



Sources: Various integrated resource plans (IRPs) for Newfoundland and Labrador Hydro (NL Hydro), New Brunswick Power, Nova Scotia Power (NS Power), and Maritime Electric. The CELT report for ISO-NE. Independent Electricity System Operator (IESO) website.

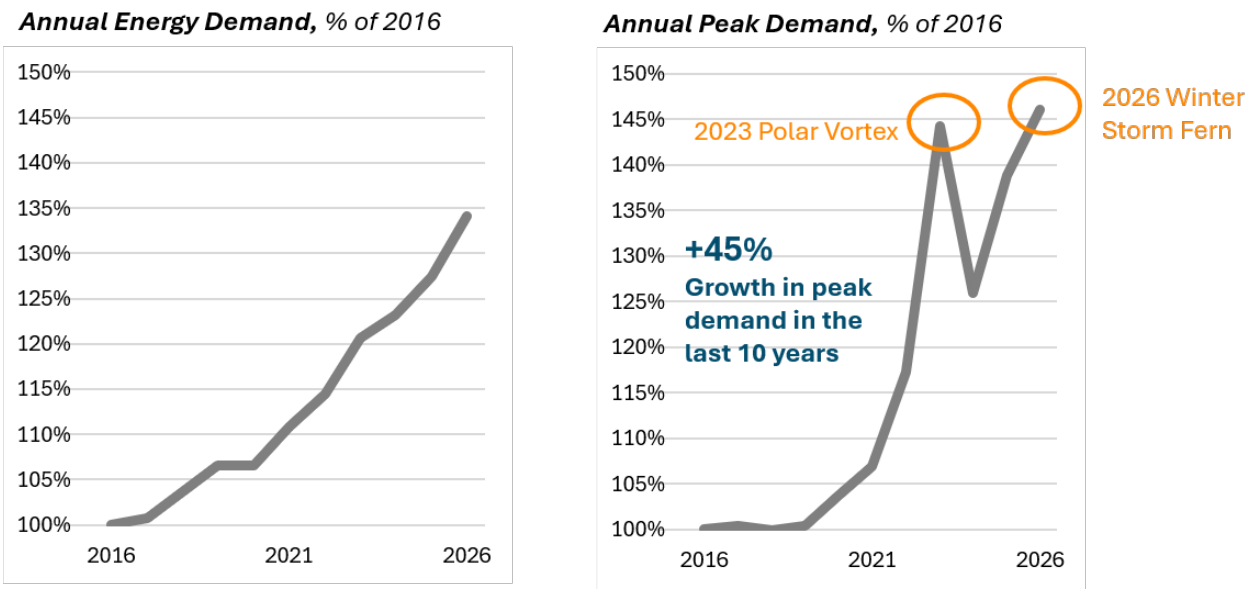
[6] The sum of the individual subsea cable ratings is 560 MW, but the interconnection is limited to 300 MW due to constraints to the New Brunswick transmission system and an "N-1" contingency of the four subsea cables.

[7] New Brunswick Power Corporation, Open Access Transmission Tariff (OATT), https://tso.nbpower.com/public/en/op/transmission/tariff.aspx. New Brunswick Power's Transmission and System Operator division administers the OATT and acts as Reliability Coordinator for the Maritimes Area within the Northeast Power Coordinating Council (NPCC); see https://www.npcc.org.

In the past, Maritime Electric has been able to rely on non-firm imports whenever it has needed energy beyond what could be provided by its dedicated on- and off-Island resources. This has been possible historically because Maritime Electric's peak load has generally not coincided with peak loads in the rest of the region, meaning that neighboring systems had excess capacity available during Maritime Electric's time of greatest need. While peak load events across the broader region have been driven by heating demand in the coldest hours, Maritime Electric's own peak was historically driven by holiday lighting load and other non-temperature-dependent end-uses, not necessarily coincident with the coldest temperatures of the year. However, with customers of Maritime Electric, New Brunswick Power and Nova Scotia Power increasingly adopting electrified heating, Maritime Electric's peak is now coincident with the regional peak winter demand.

Additionally, neighboring systems will be stretched to add resources quickly enough to meet their own growing demand, a challenge that will be exacerbated by planned retirements of coal stations including Belledune in New Brunswick by 2030 and Lingan generating station in New Waterford, Nova Scotia, and with uncertainty about future availability of New Brunswick Power's Mactaquac hydroelectric resource. Given increasing wintertime reliability challenges across the Atlantic provinces, Quebec, and New England, Maritime Electric can no longer count on imports of non-firm, as-available energy from neighboring systems in lieu of dedicated reliable capacity.

Figure 2-3. Historical Maritime Electric Annual Energy and Peak Demand



Adding to the challenges facing Maritime Electric, its system is vulnerable to large events such as forced outages of its aging on-Island thermal capacity, Point Lepreau, or the four subsea cables across the Northumberland Strait. Of Maritime Electric's 90 MW of on-Island combustion turbines, 40 MW are over 50 years old and have a higher forced outage rate than Maritime Electric's newer 50 MW CT 3. Maritime Electric's share of Point Lepreau provides 30 MW of firm capacity (29 MW after losses) but represents another single point of exposure. Furthermore, if Point Lepreau experiences an outage during a winter critical reliability period, both Maritime Electric and New Brunswick Power would need to backfill the lost generation from other supply in the region, constraining both New

Brunswick Power and Maritime Electric simultaneously. Lastly, even when Point Lepreau is online and New Brunswick Power has available capacity, outages or constraints affecting the transmission path between New Brunswick and PEI – including those to the subsea cables, overhead transmission network in New Brunswick, or key facilities such as the Memramcook substation – can pose significant power delivery challenges to the Island.

2.2 Maritime Electric's Resource Adequacy Practices

In the past, Maritime Electric relied on the NPCC for resource adequacy modeling and need determination. The NPCC sets the regional reliability target of 0.1 LOLE.[8] NPCC's standard states that "Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the LOLE of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year".[9] New Brunswick Power is the Reliability Coordinator for the region and performs a Maritimes Area resource adequacy analysis to ensure the target is met by the region as a whole.

Maritime Electric plans to a 15% planning reserve margin, a criterion that was calibrated to satisfy the NPCC LOLE criterion[10] and was established in 1977 as part of the Interconnection Agreement between New Brunswick Power and Maritime Electric, directly after the first two subsea cables were installed.[11] The Maritimes Area as a whole plans to a 20% reserve margin, and the 15% margin for Maritime Electric was found to be the level needed for the region to meet its 0.1 LOLE criteria. Maritime Electric has historically not performed its own RA analysis and has instead relied on the NPCC and New Brunswick Power as the Reliability Coordinator for detailed RA studies, results, and metrics.

This approach worked well historically, but increasing coincidence of regional peak loads and Maritime Electric load that is growing substantially beyond what can be delivered over the subsea cables mean that a regional study is no longer sufficient to evaluate Maritime Electric's ability to meet its 0.1 LOLE standard, and specific focus must be given to on-Island capacity availability.

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[8] 2025 NPCC Maritimes Area Comprehensive Review of Resource Adequacy https://cdn.prod.website-files.com/67229043316834b1a60feba3/6994b2e9bda14cf9151c5174_2025 Maritimes Comprehensive Area Review of Resource Adequacy.pdf

[9] NERC Glossary of Terms (Resource Planner definition), https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf; NPCC Directory #1 – Design and Operation of the Bulk Power System, https://www.npcc.org/standards/regional-criteria

[10] The 15% figure is based on peak loads after subtracting controllable demand side management and interruptible customer load. Source: Supplemental Capital Budget Request, On Island for Security of Supply Project – Docket UE20742, Response to Interrogatories from Synapse Energy Economics on Behalf of Island Regulatory and Appeals Commission, Maritime Electric. 2025. https://irac.pe.ca/wp-content/uploads/Exhibit-M-6-Response-to-Interr-of-Synapse-Energy-on-behalf-of-Commission-May-16-2025-1.pdf

[11] General Rate Application Docket UE20944 Response to Interrogatories from Multeese Consulting Inc, Maritime Electric, 2019. https://irac.pe.ca/infocentre/documents/Electric-UE20944-Exhibit-M-9.pdf

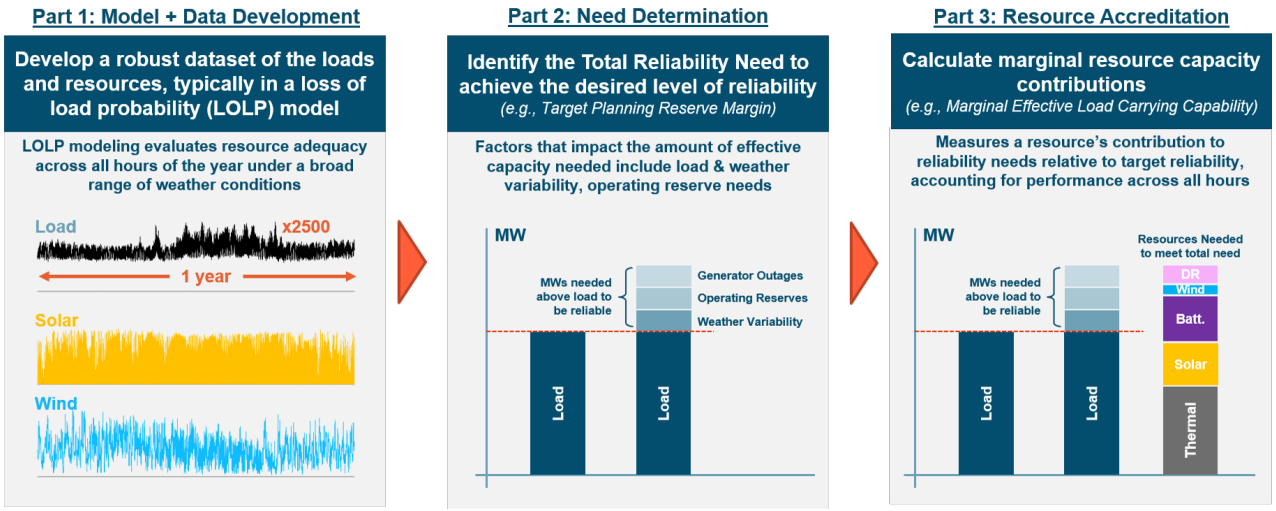
During peak load conditions, Maritime Electric will increasingly need to be capable of meeting its own peak loads without relying on additional imports beyond what is contracted firm with NBEM. This report describes the assessment performed by E3 of Maritime Electric-specific resource adequacy needs to meet its 0.1 days per year LOLE standard. This study and the 0.1 LOLE standard are consistent not only with the NPCC requirements but also with the criteria applied broadly across North America by NERC, other regional reliability entities and system operators. More information on how other jurisdictions perform resource adequacy studies and their adequacy targets is provided in Appendix A.

3. Methodology

This study uses E3's **RECAP** model to conduct LOLP modeling to calculate the TRN, PRM and ELCC values for Maritime Electric's system. The study focuses on Maritime Electric's system in 2030, when a considerable reliability gap is projected and by when new resource options could be operational.

3.1 General Modeling Framework

Figure 3-1. Key Steps for Resource Adequacy Planning Critical Periods Framework



3.1.1 Critical Periods Framework

This study employs the "critical periods" reliability framework that is emerging as the industry best practice for assuring resource adequacy. The framework utilizes established and updated methodologies, including LOLP modeling and ELCC, to address the evolving challenges of evaluating resource adequacy in systems with high penetrations of variable and energy-limited resources. A full description of the framework is provided in Appendix B.2.

The framework is organized around a central concept: ensuring that the electric system is designed to perform under its most constrained conditions. These "critical periods" are defined as periods of time when the electricity system is close to or has exceeded its maximum limits to serve electricity demand, meaning that either loss of load is occurring, or that there is genuine risk of loss of load. Historically, critical periods coincided almost exclusively with peak load conditions. However, as variable resources and storage have become an increasingly large share of resource mixes, resource availability is becoming an increasingly important driver of supply shortfall events, and the critical periods have in some cases shifted away from the highest load hours. Designing the system to perform during these critical periods is the primary challenge of resource adequacy planning.

A robust resource adequacy assessment under this framework has three components, described below and visualized in Figure 3-1:

- **LOLP Model Development:** A Monte Carlo–based loss-of-load-probability model simulates thousands of years of plausible system conditions—including load variability, weather variability, renewable output variability, and forced outage events—to calculate statistically significant reliability metrics and individual resource contributions to system reliability.
- **Need Determination:** A TRN is derived, reflecting the quantity of "perfect capacity" (in megawatts) required to achieve a specified reliability standard. This study enforces the NPCC standard of 0.1 LOLE. TRN serves as the basis for calculating the target PRM, measured as a percent above the 1-in-2 peak load.
- **Resource Accreditation:** An ELCC accounting framework is applied to measure each resource's contribution toward the TRN. ELCC reflects a resource's expected performance and ability to serve load specifically during critical periods, accounting for the complex interactive effects between different resources operating together in a portfolio. ELCC provides a technology-agnostic measurement of reliability contributions, creating an economically efficient signal for new resource investment, regardless of technology type.

Together, these three components form an internally consistent framework in which the total system need and individual resource contributions are measured on the same basis: the loss-of-load events revealed through LOLP modeling, and the ability of resources to help avoid those events. This approach enables an “apples-to-apples” comparison of the reliability value of diverse resource types. The level playing field created using this framework is particularly important in today’s grid, where the reliability contribution of new resources including solar, wind, and battery storage cannot be accurately captured through installed capacity alone, and increasingly extreme weather events drive critical periods in which many resources may perform differently from an average day.

3.1.2 Modeling Framework Inputs

In order to perform each step in the model described above, RECAP requires data characterizing loads and the resources available to serve those loads. These are listed in Table 3-1. A more detailed description of how the data is developed and used in Maritime Electric’s RECAP modeling is described in Section 4.

Table 3-1. RECAP Data Requirements

Category	Metric
Load	Simulated hourly load for multiple weather years, based on historical load and weather data
	Annual and peak load forecast for future model year (2030)
	Operating reserve requirements
Dispatchable Generation	Installed capacity
	Seasonal rated capacity
	Unit size
	Forced outage rate (FOR)
	Maintenance schedule
Renewable Generation	Installed capacity
	Hourly generation profiles for multiple weather years
	Maintenance schedule
Energy Storage	Installed Capacity
	Duration
	Round-trip efficiency
	Forced outage rate (FOR)
Imports	Transmission interface rating
	Firm import capacity
	Availability of non-firm imports
Interruptible loads and Demand response	Load reduction capacity
	Duration and frequency constraints

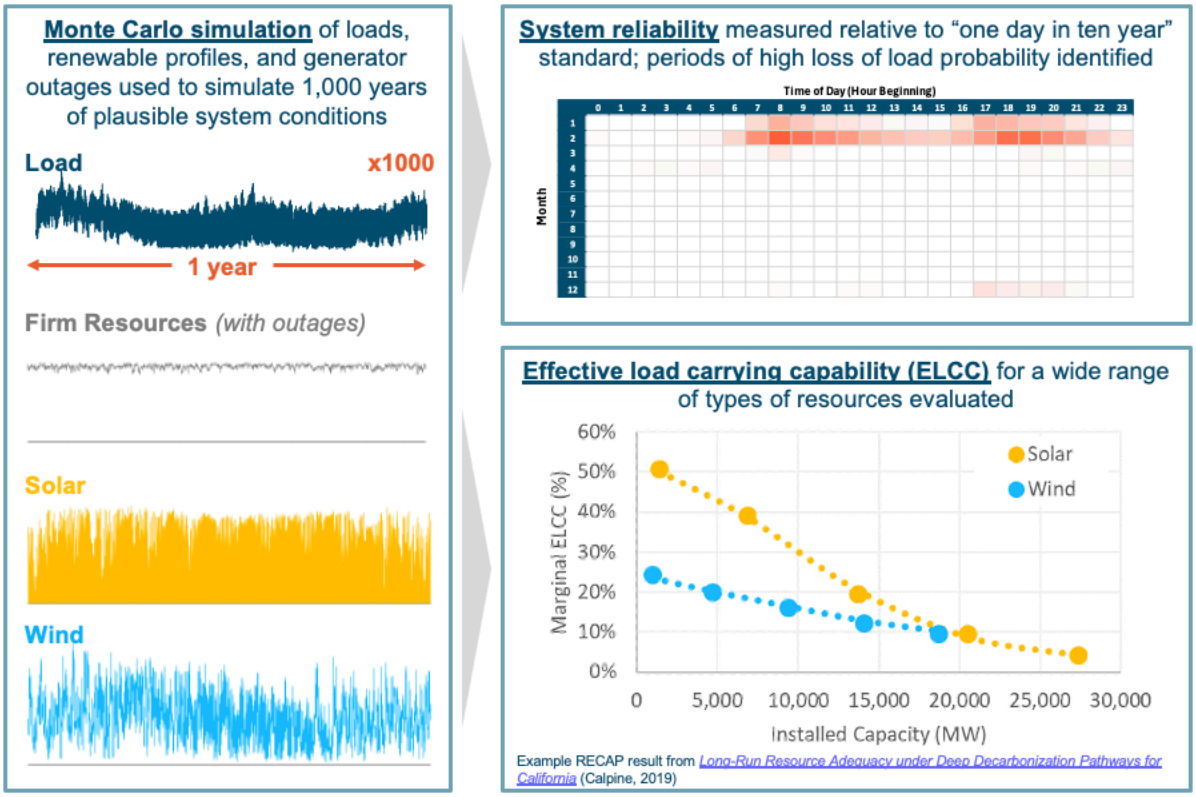
3.1.3 RECAP Methodology Overview

RECAP is a loss-of-load-probability model developed by E3 that is used to assess the reliability of electricity system portfolios, and has been used extensively across North America, including the other Atlantic provinces, New England, New York, California, Hawai'i, the Pacific Northwest, the Desert Southwest, the Upper Midwest, Florida, and many other jurisdictions. The model is designed to evaluate the resource adequacy of electric power systems, including systems with high penetrations of renewable energy and other energy-limited resources such as hydropower, energy storage, and demand response.

RECAP evaluates resource adequacy through time-sequential simulations of thousands of years of plausible system conditions to calculate a statistically significant measure of the relevant system reliability metrics. The thousands of years of system conditions (2500 years were evaluated for this

study) are generated by a stochastic Monte Carlo process that assembles different combinations of load, renewable generation, and thermal outage conditions. That process preserves the statistical correlation of these factors, creating plausible system conditions that extend beyond the historical record. RECAP simulates the operations of the electricity system in response to these conditions in order to create statistically significant estimations of key reliability metrics. See Appendix B.3 for further detail on the RECAP model, and in Figure 3-2 for an overview.

Figure 3-2. Overview of RECAP Model



3.1.4 Modeling Framework Outputs

RECAP dispatches all resources to meet hourly load plus operating reserves, then aggregates the resulting loss of load events to calculate various annual reliability statistics for the system including LOLE, Loss of Load Hours ("LOLH"), and Expected Unserved Energy ("EUE") (See Appendix B.3 for more details on the specific metrics). These annual statistics characterize the frequency, magnitude, and duration of expected loss of load events in any given system. The focus in this section is on the key outputs that this study uses to calculate the TRN for Maritime Electric's system and ELCC values for individual resources.

To measure the quantity of capacity needed to meet target reliability, RECAP uses an iterative tuning process, adding and subtracting "perfect capacity"[12] to determine the TRN. A Perfect Capacity ("PCAP") PRM is then calculated as the ratio of TRN and the median peak, minus one.

This same tuning algorithm is used to calculate resource ELCC values. The steps are as follows:

1. "Tune" the system to the reliability standard by adding or subtracting perfect capacity
2. Add a specific resource to the system, improving system reliability
3. Remove perfect capacity until the reliability standard is achieved
4. Divide the quantity of perfect capacity removed by the nameplate capacity of the resource added to determine its ELCC in percentage terms

Appendix B.5 provides additional detail regarding RECAP's process for calculating ELCCs.

3.2 Specific Maritime Electric Modeling Considerations

The objective of this analysis is to determine the need for on-Island capacity in 2030 and to evaluate how new resources can contribute to meeting that need. Doing so requires accurately modeling the unique characteristics of Maritime Electric's system. This section outlines key methodologies and assumptions utilized to evaluate Maritime Electric's unique resource adequacy needs.

3.2.1 New Brunswick Intertie

Maritime Electric depends on its intertie with New Brunswick for both energy and capacity throughout the year, making the treatment of this interface critical for evaluating the system's reliability. The intertie's total transfer capability is allocated across several uses: firm capacity contracted for Maritime Electric, the City of Summerside's allocation, Maritime Electric's participation share of Point Lepreau, and non-firm as-available energy.

As described in Section 2.1, Maritime Electric has historically relied on non-firm energy imports to help meet resource adequacy needs on the Island. While Maritime Electric can no longer rely on non-firm imports during peak load events, non-firm imports can still play an important role in meeting Maritime Electric's needs during other periods. On days outside of the peak load periods, resource outages and low wind generation can still expose Maritime Electric to reliability risk that non-firm imports can help address. For this reason, E3 developed assumptions for hourly non-firm import availability beyond the guaranteed firm imports defined by the EPA with NBEM, described in Section 4.4.

[12] A perfect capacity resource is an ideal generator that is available in all hours at full capacity. ELCC for a perfect capacity resource is 100%. It's used as a reference to measure how much a resource contributes to system reliability.

3.2.2 Operating Reserves

Beyond serving load, electricity systems must hold operating reserves with resources kept available to respond to short-term contingencies such as the sudden loss of a generating unit or rapid fluctuations in load and variable generation, and these requirements are generally incorporated into LOLP modeling. However, New Brunswick Power provides operating reserves to Maritime Electric in exchange for monetary payment in their role as the Balancing Authority, and Maritime Electric has no obligation to carry its own operating reserves.[13] Therefore, operating reserves are not modeled as an incremental capacity need for Maritime Electric.

3.2.3 Interruptible Loads

Maritime Electric has contracts with non-residential customers which allow it to call upon 14 MW of loads to be interrupted. This is considered a "last resort" option which historically was not a resource Maritime Electric had to rely upon. Given contracting terms and aligning with Maritime Electric's planning practices, these interruptible loads are assumed as always available without restrictions on call frequency or duration. Therefore, interruptible loads are accredited as a resource with an ELCC of 100% towards meeting the TRN.

3.2.4 Thermal Resource Accreditation

Traditionally, thermal resources have been accredited using either their "Installed Capacity" ("ICAP") or "Unforced Capacity" ("UCAP") value, where ICAP is a thermal resource's nameplate capacity and UCAP value is its nameplate capacity derated by its expected annual forced outage rate.[14] While UCAP accreditation accounts for the direct impact of forced outages on an individual unit, it does not capture the fact that outages across multiple thermal resources can compound at any point in time and create a larger reliability risk, resulting in an aggregate availability during critical periods that is less than the fleet-wide average availability. The ELCC methodology used for this study captures this effect and harmonizes the capacity accreditation methodology across all resources (including renewables and storage).

[13] New Brunswick Power Corporation, Open Access Transmission Tariff (OATT), https://tso.nbpower.com/public/en/op/transmission/tariff.aspx. New Brunswick Power's Transmission and System Operator division administers the OATT and acts as Reliability Coordinator for the Maritimes Area within the Northeast Power Coordinating Council (NPCC); see https://www.npcc.org.

[14] UCAP = ICAP × (1 − Forced Outage Rate)

3.3 New Resource Options Evaluated

Maritime Electric is pursuing additional resources to meet its projected capacity needs. This analysis calculates the perfect capacity contribution of new thermal generation and battery storage, which are the primary options available in 2030, as well as wind, solar and other resources.

The analysis also examines the interactive effects, both synergistic and antagonistic, between resources as penetration increases. Individual resource types are subject to diminishing marginal returns as the periods in which they generate become "saturated" with available energy. Some resource pairs, such as renewables and storage, have complementary capabilities and provide more value in combination than either would individually. Other resource pairs, such as storage and hydropower, have similar capabilities and therefore exacerbate individual saturation effects when added in combination. The contribution of new resources is expressed through ELCC curves, showing how a resource's marginal capacity value falls as more of it is added. See Appendix B.5 for further detail on calculating ELCCs.

The resulting ELCC values and the analysis of how they close the projected gap are presented in Section 5. The resource options evaluated are:

- Thermal generation (e.g. combustion turbines (CT) or reciprocating internal combustion engines (RICE)) of varying unit sizes
- 4- and 8-hour lithium-ion battery storage
- Onshore wind
- Solar
- Demand response (varying duration and call constraints)

4. Modeling Inputs and Assumptions

This section describes the development of the modeling dataset and how it is used for Maritime Electric's 2030 resource adequacy study. This includes:

- Description of Maritime Electric's existing loads and expected load growth
- Characteristics assumed for Maritime Electric's existing resources and imports
- Characteristics assumed for Maritime Electric's new resource options

Data used in this study is current as of May 2026. Any findings, conclusions, or recommendations presented are based on data collected and analyzed up to this date.

4.1 Load Forecast and Hourly Load Shaping

This section describes the load assumptions used for this study. Maritime Electric's 2025 load forecast is the source for the annual energy and median (i.e. 1-in-2) peak load forecast in 2030. This forecast includes projected growth of specific electricity demand end-uses, such as residential and commercial space heating as well as electric vehicles. From 2025 to 2030, combined commercial and residential annual heating load is projected to grow from 351 GWh to 404 GWh, representing a 15% increase. Over the same period, non-heating load grows at about 7% (1,404 GWh to 1,496 GWh). Heating load grows more than twice as much as non-heating load in 5 years.

Whereas "baseline" loads are comparatively stable, heating load is strongly temperature driven. The levels of electrification described above raise not only annual energy consumption but, even more substantially, the annual peak, especially under extreme cold conditions as observed during the February 2023 and January 2026 cold snaps with record-breaking loads. Maritime Electric's peak load has grown from 249 MW in 2016 to 363.8 MW in 2026, representing a 45% increase in peak load over 10 years. The higher peak load in 2026 was also driven by Winter Storm Fern, as noted in Section 2.1. Looking forward, median peak demand is expected to grow to 392.8 MW by 2030 and further to 423.6 MW by 2035, primarily driven by space heating demand, estimated by Maritime Electric as 161.8 MW of the 2030 peak.

Because loss-of-load is more likely to occur during extreme high load events, the study requires additional calculations of electric loads during extreme cold weather conditions. Due to the temperature-dependence of electric heating loads, Maritime Electric must plan future conditions with increasing weather variability relative to "typical" conditions, since higher peak variability results in greater need for reliable capacity. To capture these dynamics, the modeling framework simulates 55 weather-years of hourly load conditions, based on the historical hourly temperature and load relationship as well as Maritime Electric's estimated space heating and temperature relationship. Figure 4-1 presents the annual peak load across 55 simulated weather years (1970–2025), scaled to Maritime Electric's 2030 median peak forecast of 393 MW. Highlighted in red are the 2023 Winter Polar Vortex and the record cold temperatures of 1981, which drive load above the

median peak and illustrate the kind of extreme conditions Maritime Electric must plan for. E3's load shaping process is described in detail in Appendix C.1.

Figure 4-1. Peak Load Distribution across 55 Simulated Weather Years, scaled to Maritime Electric's 2030 Median Peak

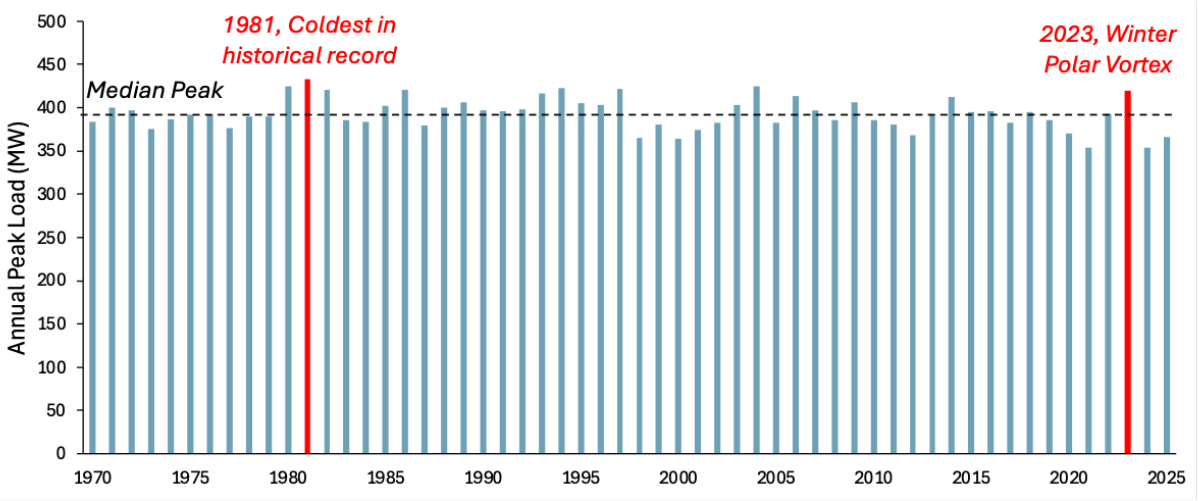
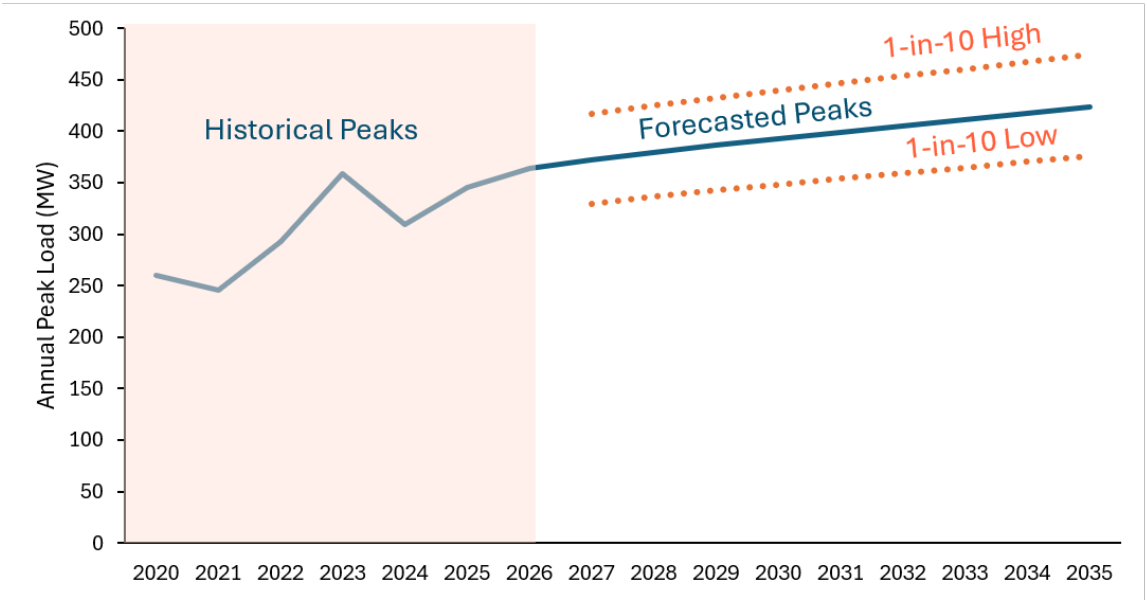


Figure 4-2 shows the forecasted median peak for Maritime Electric's system alongside the spread of potential peak loads using the 1-in-10 low and high conditions, based on the 55 years of simulated hourly loads described above. The variability between the P90 and median peak loads is a key driver of the PRM.

Figure 4-2. Historical and Forecasted Peak Load (MW)



4.2 Existing Thermal Resources

Thermal resources are dispatchable generators that produce electricity by burning fuel or, in the case of nuclear units, through fission to evaporate water to move a turbine. Because their output can be called upon when needed (dispatchable) for long periods[15], they are described as "firm" generating resources. Maritime Electric's thermal fleet consists of three diesel combustion turbine ("CT") units and a share of the Point Lepreau Nuclear Generating Station, imported from New Brunswick.

Thermal generators are not always available when needed: they can trip offline unexpectedly (forced outage) or be unavailable due to planned maintenance (unforced outage). Representing both forced and unforced outages accurately is essential for resource adequacy modeling. Additionally, lack of fuel availability can sometimes prevent a thermal generator from operating when needed. Specific methodologies and assumptions for thermal resources are as follows:

+ RECAP captures forced outages for each unit through its forced outage rate ("FOR") and mean time to repair ("MTTR"). These parameters are used to draw stochastic outages that determine when, and for how long, each unit becomes unavailable across the simulation. These outages are drawn independently of load, so they can fall in any hour rather than only at peak. This means a thermal outage can occur even when load is high. This dynamic can be especially consequential for a small system like Maritime Electric where certain thermal units represent a sizable share of the system need.

[15] Subject to fuel sufficiency and forced and unforced outages.

- For unforced outages, maintenance schedules for the three on-Island diesel CTs are modeled based on the 2029 schedule provided by Maritime Electric. The Point Lepreau maintenance schedule was derived by considering the historic yearly planned outages in the Spring.
- Fuel security is assumed not to be a binding constraint, since existing investments and infrastructure allow fuel to be stored on site for multiple days of operation. Fuel security could become an issue during an emergency event such as an extended subsea cable outage. This issue could be explored in a resilience analysis.

Table 4-1 shows the thermal unit operating characteristics modeled in RECAP. The FOR and MTTR assumptions provided by Maritime Electric reflect the historic range of outage behavior across the on-Island units of different ages, with older and newer units carrying different outage characteristics. For Maritime Electric's share of Point Lepreau, special consideration was placed in the outage performance of these plants after discussion with the Maritime Electric staff. In 2024, Point Lepreau underwent substantial maintenance with the objective of reducing the outages of this important generator for the region, improving expected performance and reducing outage risk. The 7% FOR aligns with going-forward planning assumptions by New Brunswick Power.

Table 4-1. Existing Thermal Resource Characteristics

Generator Name	Nameplate Capacity (MW)	Summer Capacity (MW)*	Winter Capacity (MW)*	Forced Outage Rate (FOR)	Mean Time To Repair hours (MTTR)
Borden-Carleton CT1 Diesel	15	9	13	10.00%	106
Borden-Carleton CT2 Diesel	25	19	24	10.00%	28
Charlottetown CT3 Diesel	50	36	49	5.00%	12
Point Lepreau Nuclear (Import from New Brunswick)	29**	28	28	7.18%	393

**Thermal resources winter and summer ratings represent the maximum output they can be expected to provide during high load periods in each season according to Maritime Electric.*

***Point Lepreau was modeled as 29 MW of nameplate at Maritime Electric's system after accounting for 3.3% transmission losses. Summer and winter ratings show effective values after accounting for losses.*

4.3 Variable Resources

Currently, Maritime Electric's system has almost 200 MW of wind and solar generation, significantly more than regional peers in terms of renewable penetration relative to its system size, and higher than most utilities in North America. Wind is the primary source of on-Island generation, while

behind-the-meter solar penetration is expected to continue growing. While these resources provide clean energy, their output is variable and weather dependent. In particular, these resources are subject to extended generation droughts, outages, and cold-weather cutoffs, all of which affect system reliability.

4.3.1 Wind Resources

Maritime Electric receives energy and capacity from eight existing wind projects. This study leverages historical metered wind generation data to characterize the range of output conditions that can be expected from existing and new resources. Maritime Electric provided E3 with ten years of metered data for the existing wind fleet. This metered data is aggregated in four groups based on shared locations of their meter interconnections.

In consultation with Maritime Electric staff, E3 developed hourly generation profiles that can represent expected future performance of existing and future wind resources. This pre-processing step adjusts for factors including significant maintenance and refurbishment in historical data, as well as new resources coming online with improved power curves and performance characteristics.

Table 4-2 shows the input nameplate capacities and average capacity factors for each aggregated wind group, the wind resources assigned to each group, and the average capacity factors of the underlying raw data prior to processing. The detailed pre-processing steps of the metered data are covered in Appendix C.2.

Table 4-2. Existing and Planned Wind Resource Characteristics

Wind Groups	Wind Resources in Group	2030 Nameplate Capacity (MW)	Historical (Raw) Capacity Factor	Adjusted (Modeled) Capacity Factor
Wind 1	North Cape, Norway, Aeolus & WEICAN	32.7	38.1%	38.1%
Wind 2	Eastern Kings Phase I	30	34.0%	34.1%
Wind 3	Hermanville / Clearspring	27	30.7%	34.4%
Wind 4	Eastern Kings Phase II	29.4	(NA / new in 2025)	46.6%

4.3.2 Solar Resources

Maritime Electric's solar resources are mostly distributed behind-the-meter ("BTM") solar, which accounts for 55 MW (or ~84%) out of the total 65.1 MW installed nameplate capacity in 2026. Forecasts provided by Maritime Electric show a growth in installed BTM solar resources in the region, reaching 58 MW by 2030. The remaining 10 MW are from the Slemon Park Microgrid which is the only utility-scale solar resource in Maritime Electric's supply portfolio. As they are all relatively new, historical generation data for these solar resources covering multiple years was not available.

Instead, E3 developed hourly solar profiles over a set of 26 historical weather years (1998-2023), simulated using the United States National Laboratory of the Rockies' reV Model and System Advisor Model (SAM) toolkits.[16] The technical details of the development of these profiles can be found in Appendix C.3. Table 4-3 shows the input nameplate capacities and average capacity factors of both the distributed BTM and the Slemon Park Microgrid.

Table 4-3. Existing Solar Resource Characteristics

Resource	2030 Nameplate Capacity (MW)	Capacity Factor (%)
Distributed BTM Solar	58.3	11.4%
Slemon Park Microgrid	10	15.0%[17]

4.4 Imports from New Brunswick over Subsea Cables

A total of 300 MW can be imported through the subsea cables that connect New Brunswick to Prince Edward Island. Maritime Electric has rights to 270 MW of the total intertie capacity while the City of Summerside has rights to the remaining 30 MW. Of the 270 MW, Maritime Electric primarily utilizes the intertie to access its 30 MW participation share in the Point Lepreau Nuclear Generating Station and access the 190 MW of firm contracted imports from NBEM. Beyond the firm imports, utilizing the rest of the intertie, Maritime Electric can purchase up to 50 MW of non-firm imports on a short-term basis provided surplus supply exists in the broader region. All imports are subject to 3.3% losses across the intertie before they interconnect to the rest of the on-Island grid.

4.4.1 Firm Imports

The contracted 190 MW of capacity-backed energy imports is considered firm and always available (i.e., an ELCC of 100%) for the purposes of the RA study, including during a Point Lepreau outage, consistent with the intertie being modeled as fully available. According to the terms of the EPA between NBEM and Maritime Electric, these imports would only become partially unavailable in the case of loss-of-load in New Brunswick or during multiple cable outages, scenarios not considered in this study. Given 3.3% of line losses, firm imports are assumed as 184 MW when delivered to Maritime Electric's system. The availability of Point Lepreau is subject to forced outages and described in more detail in Section 3.2.1.

[16] reV model is a detailed spatial-temporal modeling assessment tool that calculates energy capacity, generation, and cost based on geospatial intersection with grid infrastructure and land-use characteristics. SAM is a detailed techno-economic model, was used to calculate grid-connected photovoltaic system's hourly electrical output.

[17] The higher capacity factor from the utility-scale resource relative to BTM solar stems from improved optimal panel orientation in the solar array relative to rooftop installations.

4.4.2 Non-Firm Imports

Maritime Electric can purchase additional non-firm energy from New Brunswick beyond its firm contract when surplus capacity is available in the region, utilizing the remaining 50 MW of intertie capability (48 MW after losses). Depending on the time of year and regional availability, non-firm imports may be purchased by Maritime Electric on a short-term basis. Working with Maritime Electric, E3 developed the following assumptions to characterize the availability of non-firm imports:

- **No availability during a Point Lepreau winter outage** – Due to its size, a Point Lepreau outage creates the risk of a resource shortfall across the broader region. E3 assumes no non-firm imports are available during a Point Lepreau outage.
- **Limited availability during winter peak load conditions** – E3 assumes non-firm imports are limited during peak load conditions in December, January and February of each year. The specific assumptions about peak load conditions are shown below in Figure 4-3.
- **Full availability during shoulder and off-peak conditions** – During all other periods, non-firm imports are assumed available as needed up to the 48 MW (loss-adjusted) subsea cable capacity.

Working with Maritime Electric, E3 developed an hourly MW availability profile for non-firm imports in the 2030 winter season as a function of Maritime Electric's load. When Maritime Electric's hourly electric load is less than 304 MW, up to 48 MW of non-firm imports are assumed to be available. This represents 80% of wintertime hours and 94.5% of all hours. No non-firm imports are available when Maritime Electric's load is above 324 MW, representing the highest 10% of wintertime hours or 2.6% of all hours. These are the conditions when other utilities in the region are likely also facing high load conditions and are unlikely to have surplus energy available. A linear interpolation is used when load is between 304 and 324. Figure 4-3 shows the load thresholds, the MW of non-firm imports available, and the percentage of total winter and annual hours affected. Figure 4-4 shows an illustrative winter week and the availability of non-firm imports based on hourly load.

Figure 4-3. Illustration of Non-Firm Import Availability and Load Level Thresholds

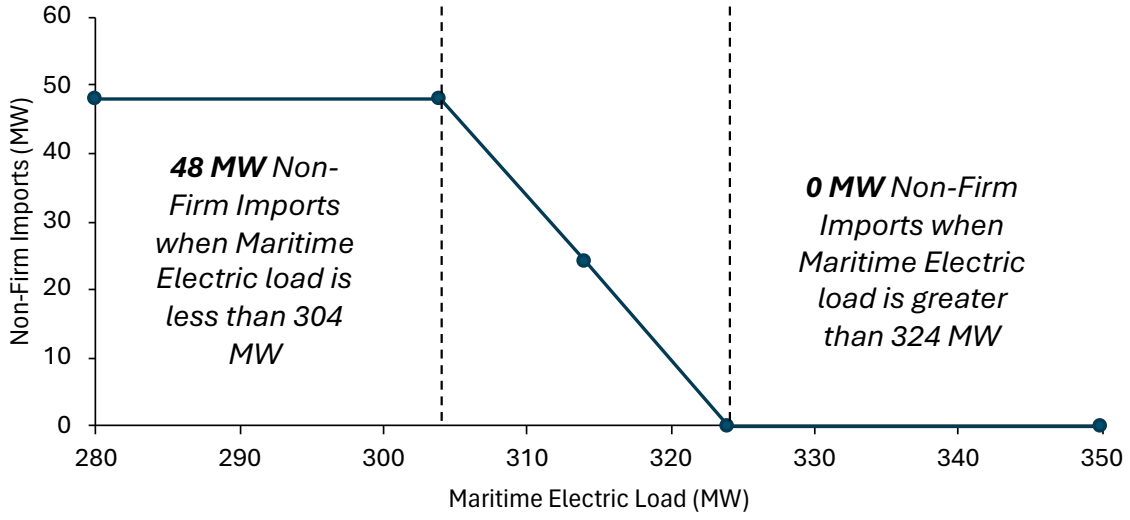
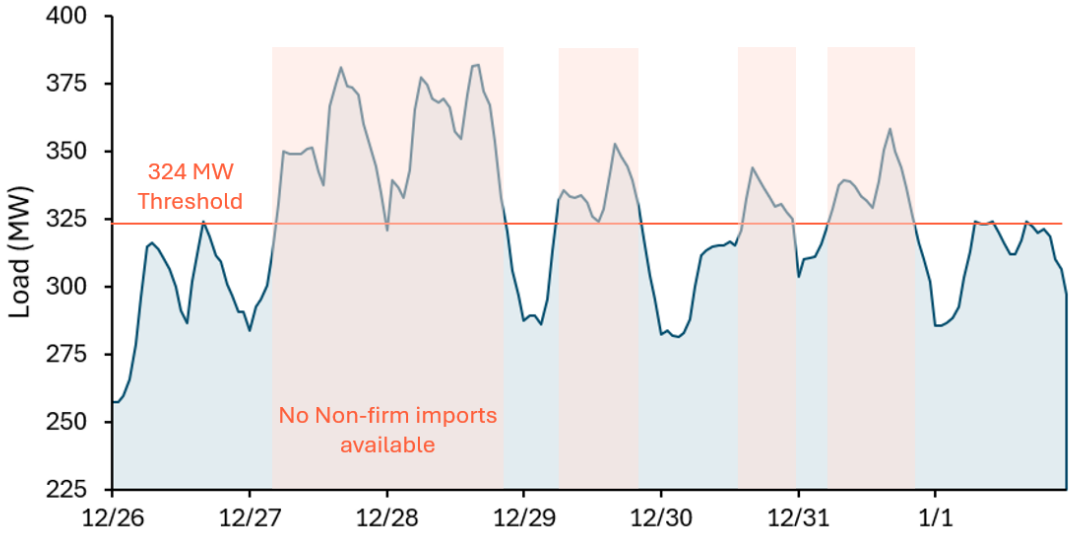


Figure 4-4. Non-Firm Import Availability for an Illustrative Winter Week



4.4.3 Intertie Availability and Resilience

Finally, the New Brunswick intertie itself is modeled as fully available, with no forced outage rate or transmission constraints applied to the interconnection. This is appropriate and consistent with industry practice given both the magnitude of the potential impact, the likely expense of planning to 0.1 LOLE when considering the potential for extended cable outages, and the lack of sufficient data to develop a robust statistical estimate of the likelihood of these events. However, this means that the potential for a reliability event driven by an intertie outage is not considered as part of this analysis, and the TRN from the study should be interpreted as the quantity of perfect capacity needed to achieve 0.1 LOLE, assuming all cables are in service.

However, the loss of one or more cables would create a very significant reliability challenge for Maritime Electric. Given the significant and potentially serious consequences of such an event, E3 recommends that Maritime Electric conduct a separate resilience analysis to evaluate whether any *additional* on-Island thermal capacity is needed, beyond what is identified in this study, to maintain public health and safety during an extended intertie outage.

4.5 New Resource Options

This section describes how each of the new resource options outlined in Section 3.3 is characterized in the model.

4.5.1 Thermal

Potential new thermal generation is modeled in unit sizes of 20 MW (e.g., RICE unit) and 50 MW (e.g., CT unit). These units are assigned the same forced outage characteristics as the existing CT3, i.e., a

forced outage rate of 5% and a mean time to repair of 12 hours. Fuel supply constraints are not modeled in this analysis as fuel is assumed to always be available. The representation of new thermal resources is consistent with the representation of thermal resources as described in Section 4.2.

4.5.2 Renewables

New renewable energy projects are either developed by Maritime Electric or purchased from third parties, such as the PEI Energy Corporation ("PEIEC"). This study models renewable additions that are not directly based on projects currently planned or under consideration but rather represented by newly added solar and wind, like PEIEC's existing Eastern Kings Wind Phase II and Slemon Park Microgrid Solar.

New solar is represented using the same operational characteristics, simulated hourly generation, and 15% capacity factor as the Slemon Park Microgrid solar profile. Behind-the-meter solar is treated separately, with projected growth already modeled and based on the forecast provided by Maritime Electric, as described in Section 4.3.2.

New wind is modeled as additional capacity at a higher capacity factor of 46.6%, represented using the same operational characteristics and simulated hourly generation as the Eastern Kings Wind Phase II project.

4.5.3 Storage

Electricity storage resources are dispatchable up to their full nameplate capacity when needed but are subject to limitations based on the quantity of stored energy. Maritime Electric does not currently operate energy storage resources. For the purposes of this study, energy storage technology is represented by 4- and 8-hour lithium-ion battery energy storage systems. While the operational history of battery storage at grid scale is relatively limited in the Atlantic provinces, there is an increasing amount of real-world evidence about its performance available from other systems in North America. In California, outage rates for energy storage have averaged 10% since 2020[18] but have fallen in recent years with continued deployment.

For the purposes of this study, new 4- and 8-hour energy storage is modeled using a round-trip efficiency of 85%, a forced outage rate of 5%, and a mean time to repair of 24 hours[19]. This value is lower than current experience, representing an assumption that forced outage rates of storage will continue to decline with increased battery deployment.

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[18] See slide 45 of E3 presentation to APS' Resource Planning Advisory Council (Oct 26, 2022), available at: https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS-RPAC-Meeting-Presentation-102622.ashx?la=en&hash=9AE20E699D178AFCF8AB30BF9C64FFED

[19] Forced outage rates for BESS assumed in LOLP modeling analyses for ISO-NE, PJM, California Public Utilities Commission range from 3.8-5.4%.

4.5.4 Demand Response

Similar to storage resources, demand response programs are also typically subject to limitations based on dispatch duration and number of events.[20] However, demand response does not typically require a charge and discharge cycle.

As described in Section 3.2.3, Maritime Electric's existing interruptible loads are modeled as always available, without limits on call frequency or duration, and are therefore accredited at a 100% ELCC. To evaluate the capacity contribution of additional demand response under more representative new program definitions and operating constraints, this analysis models representative load-interruption demand response resources in 10 MW increments. Customer non-response to calls is not modeled for these programs, meaning that the program is assumed to provide 10 MW of response whenever called. Their effective capacity contribution is assessed across a matrix of call-duration and annual call-frequency limits:

Table 4-4. Characteristics of Generic Demand Response Program Evaluated

Call Duration (Hours)	Number of Calls per Year (Calls)
4	18
6	12
8	9
12	6
24	3
72	1

[20] See PJM ELCC / RRS Model Evaluation for more details on Demand Response best practices, available at: https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20251209/20251209-item-02---pjm-elcc-rrs-model-evaluation---e3-report.pdf

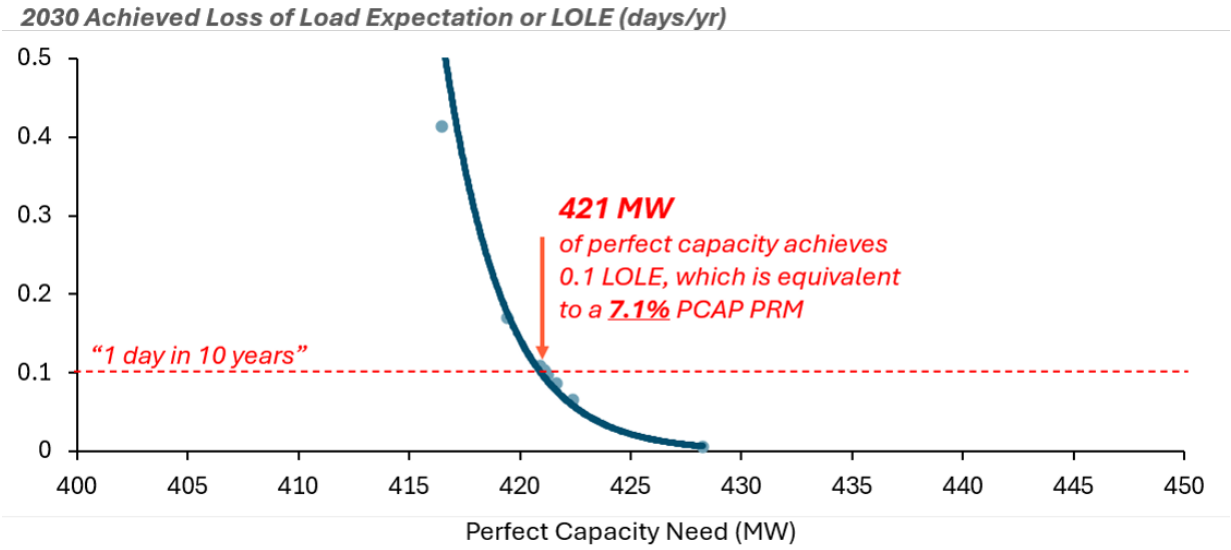
5. Results

This chapter provides detailed results for Maritime Electric's need and capacity accreditations, along with information and insights that explain these results and provide intuition into specific values.

5.1 Total Reliability Need and Existing Resources in 2030

Under the 2030 load and resource assumptions in this study, meeting a LOLE reliability standard of 0.1 days per year requires a **TRN of 421 megawatts (MW)**. This translates to a Perfect Capacity (PCAP) PRM of 7.1%[21] above the forecasted median peak demand of 393 MW. There is a positive and non-linear relationship between resource availability and reliability. The lower the quantity of capacity available, the disproportionately greater the expected loss of load. Figure 5-1 demonstrates the relationship between capacity availability and LOLE for the 2030 Maritime Electric system. This relationship demonstrates that having insufficient capacity even by a few MWs could result in loss-of-load that is significantly higher than the standard of 0.1 days/year.

Figure 5-1. Determining Planning Reserve Margin (PRM) Requirement: Loss of Load Expectation (LOLE) for 2030



RECAP is used to simulate the availability of Maritime Electric's current resources to meet its forecasted 2030 loads, described in Section 3.1.3. The result indicates that Maritime Electric's current portfolio of resources would be insufficient to meet the 0.1 LOLE standard. The difference between the equivalent perfect capacity of the base portfolio and the required capacity needed to

[21] This corresponds to a PRM requirement between 15% - 16% when expressed using more traditional ICAP accounting conventions for thermal resources.

meet the planning reserve margin is defined as the "Capacity Shortfall / (Surplus)" and is a direct output of RECAP. The model indicates that Maritime Electric's system faces a **resource shortfall of 115 MW**, prior to considering the impact of additional procurement.

Table 5-1. 2030 Maritime Electric Load and Resource Balance

2030 Load & Resource Balance	Units	2030
NBEM Firm Imports	Perfect MW / ELCC	184
Interruptible Loads[22]	Perfect MW / ELCC	14
On-Island Resources & Point Lepreau[23]	Perfect MW / ELCC	108
Total Perfect Capacity Available	Perfect MW / ELCC	**306**
Peak Demand	MW	393
Perfect Capacity Planning Reserve Margin	%	7.1%
Total Reliability Need (TRN)	Perfect MW	421
Capacity Shortfall	**Perfect MW**	**115**

5.1.1 Perfect Capacity (PCAP) and Installed Capacity (ICAP) Accounting

To provide continuity and comparability with previous analyses, a PRM requirement using Maritime Electric's previous ICAP accounting convention is provided in Table 5-2. Under the ICAP convention, thermal resources are counted at their full installed capacity, so a single reserve margin must simultaneously cover the forced outages of those units and weather-driven variability in load to meet the 0.1 days-per-year LOLE standard. The PCAP convention instead separates these components: each resource is accredited at its ELCC, which reflects its forced outages and its availability during the system's highest-risk hours while the remaining reserve margin covers weather-driven variability in load. Because thermal resources' ICAP-accredited capacity exceeds their ELCC-accredited capacity, the ICAP PRM requirement is correspondingly higher than the PCAP PRM used in this study.

An additional difference is that the PCAP method treats demand response and interruptible loads as resources, whereas Maritime Electric's previous ICAP method treated it as a reduction in its peak requirement. Lastly, previous accounting did not derate the NBEM firm imports for 3.3% line losses. Maritime Electric would need an ICAP PRM of 18.5% to meet the 0.1 LOLE standard in 2030, higher than the 15% ICAP PRM requirement it has used to date. Figure 5-2 shows the differences between the ICAP and PCAP accounting frameworks. Ultimately, the shortfall position is identical under the two conventions.

[22] Interruptible Loads are not explicitly modeled, as described in Section 3.2.3. Their impact is directly measured by reducing capacity shortfall.
[23] The portfolio value reported here is inclusive of all interactive effects including saturation effects and diversity benefits.

Table 5-2. 2030 Maritime Electric Load and Resource Balance under PCAP & ICAP frameworks

2030 Load & Resource Balance	Units	2026 Maritime Electric Resource Adequacy Study	Prior ICAP Accounting
NBEM Firm Imports	MW	184	190[24]
Interruptible Loads (as a Resource)	MW	14	-
On-Island Resources & Point Lepreau	MW	108[25]	144[26]
Total Capacity Available	MW	**306**	**334**
Gross Peak Demand	MW	393	393
Interruptible Loads (as Load Reduction)	MW	-	14
Peak Demand	**MW**	**393**	**379[27]**
Planning Reserve Margin	%	7.1%	18.5%
Total Reliability Need	MW	421	449
Capacity Shortfall	**MW**	**115**	

5.2 Characterization of Reliability Risks in 2030

The periods of highest risk in Maritime Electric's system occur during winter mornings and evenings but can potentially stretch across entire days during cold snaps. The drivers of system risk periods are described below:

1. **High Peak Demand,** high electric heating demand during cold winter days and weeks
2. **Low Variable Generation**, periods of consecutive low wind and solar outputs
3. **Large Thermal Unplanned Outages,** unexpected generator outages for on-Island and Point Lepreau capacity

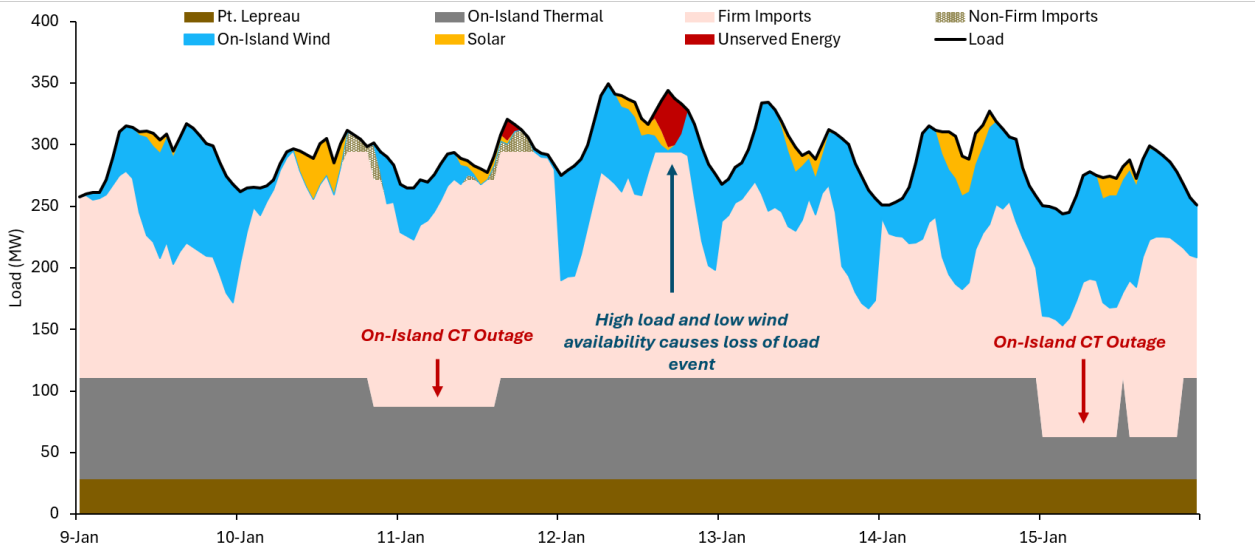
Figure 5-2 illustrates a winter week in 2030 simulated in RECAP where all three factors combine, resulting in potential loss of load (unserved energy) for Maritime Electric. In this example week simulated in RECAP, the following factors are highlighted:

1. **Low Wind Generation** on Jan 11th contributes to unserved load despite moderate loads, full availability of firm imports, on-Island thermal generation, and even some non-firm imports.

[24] Previous accounting did not derate NBEM firm imports for 3.3% line losses.
[25] The portfolio value reported here is inclusive of all interactive effects including saturation effects and diversity benefits.
[26] Prior ICAP accounting accredits 89 MW to existing Combustion Turbines On-Island, 29 MW to Point Lepreau, and 26 to existing wind portfolio - not assuming incremental wind resources, as noted in Section 4.3.1.
[27] Interruptible loads modeled as a load reduction under previous Maritime Electric ICAP accounting, making the effective peak considered for PRM calculations 379 = 393 -14 MW.

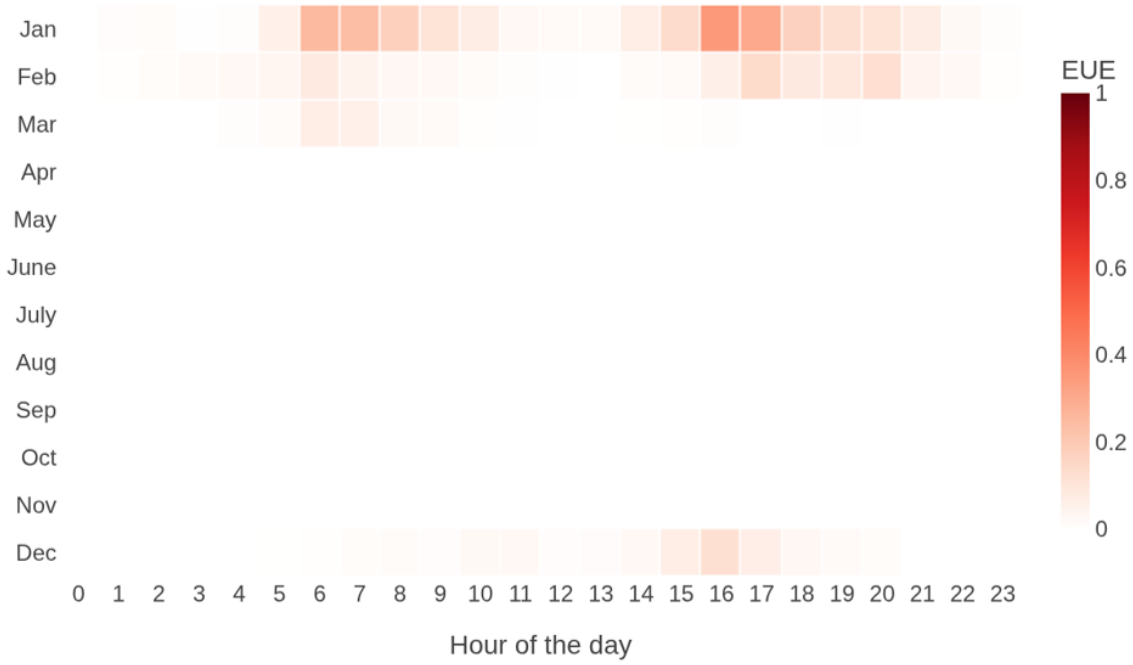
2. **High Peak Demand and Low Wind Generation** on Jan 12th lead to unserved load in the evening despite full availability of firm imports and on-Island thermal generation.
3. **Forced Outages of On-Island CTs** on Jan 11th and again on Jan 15th reduce total availability of dispatchable capacity on top of moderately high loads and low wind generation. These outages can lead to uniquely extended risk periods beyond just mornings and evenings.

Figure 5-2. Simulated 2030 Maritime Electric System Operations in RECAP During a Difficult Winter Week



This week is just one of thousands of winter weeks simulated in RECAP. Figure 5-3 shows a month-hour heatmap of times when Maritime Electric's 2030 system has the highest loss-of-load risk. The risk is concentrated in December through March, with the intensity being the highest in the coldest periods of January. Consistent with other systems where wintertime heating drives the highest load periods, loss-of-load risk is highest in the early morning and early evening hours.

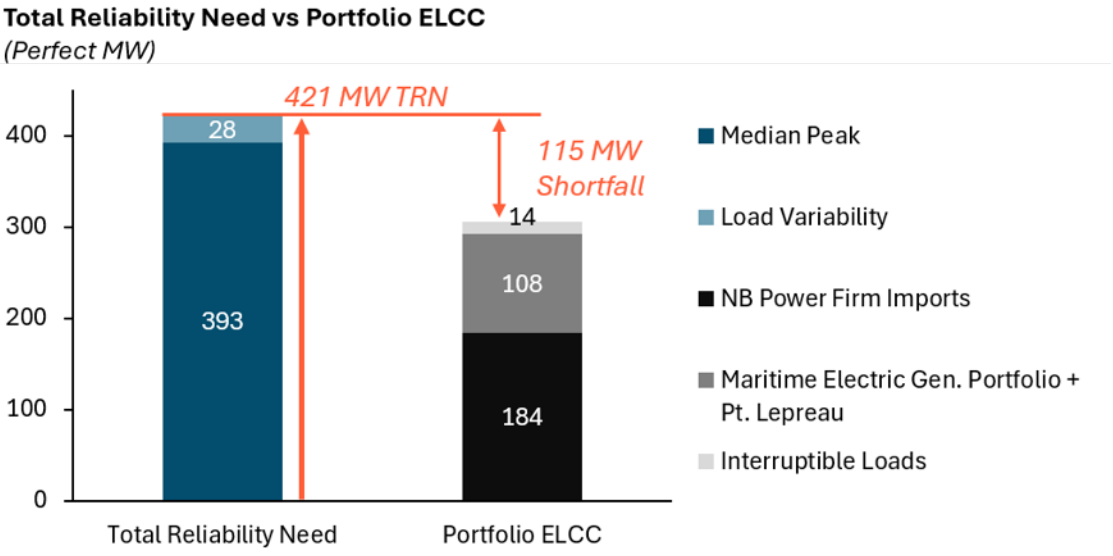
Figure 5-3. Hours with Highest Loss-of-Load Risk in 2030



5.3 Incremental Resource ELCC Analysis

To address Maritime Electric's shortfall by 2030, Maritime Electric will need 115 MW of new equivalent perfect capacity to meet a 0.1 LOLE Standard. Figure 5-4 illustrates the projected capacity shortfall in 2030.

Figure 5-4. Maritime Electric's existing resources are insufficient to meet its resource adequacy needs in 2030



This section details the incremental capacity value that resources can provide to Maritime Electric's system and its customers. For details on how ELCC is calculated, see Appendix B.5.

Each resulting table or chart shows the incremental capacity value to the 2030 existing and planned portfolio. The results are presented in two ways:

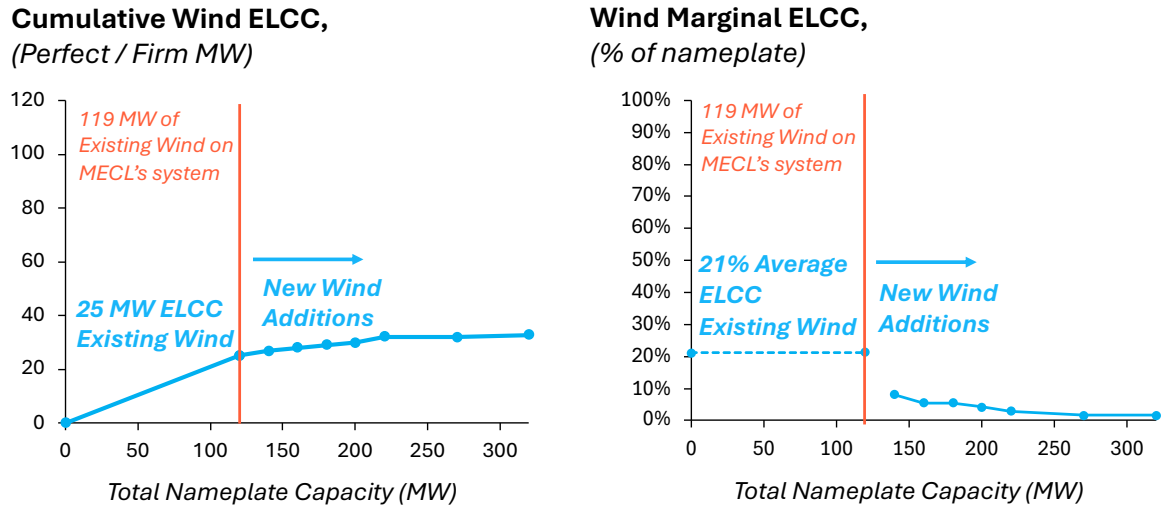
1. **Cumulative capacity value in perfect MW** – This measures a resource's total MW contribution towards meeting the reliability shortfall in 2030.
2. **Marginal ELCC as a percentage of each addition** – As more of the same resource is added to the system, this measures the effectiveness of further additions on the margin.

Incremental resources that can produce power during loss of load risk periods will have higher capacity value. Figure 5-3 highlights the critical months and hours of the year which resources need to support in order to meet Maritime Electric's 2030 reliability needs. This section describes how thermal (e.g. combustion turbines), variable (e.g., wind and solar), and energy-limited (e.g., storage and demand response) resources contribute to meeting reliability.

5.3.1 Capacity Value of Incremental Wind Resources

Maritime Electric's system already includes 120 MW of wind, providing 25 MW of cumulative equivalent perfect capacity. ELCCs of new candidate wind resources are evaluated for multiple tranches up to a total penetration of 320 MW. Figure 5-5 shows the cumulative and marginal ELCC of existing as well as new wind additions.

Figure 5-5. Cumulative & Marginal ELCC of Standalone Wind



A few observations can be made pertaining to the ELCC of new wind:

1. **Given existing penetration, incremental wind has limited value.** This is because lack of diversity across PEI's small geographical footprint means that existing and new wind

generation will be strongly correlated, and low wind production is already a driver of loss-of-load events for Maritime Electric.

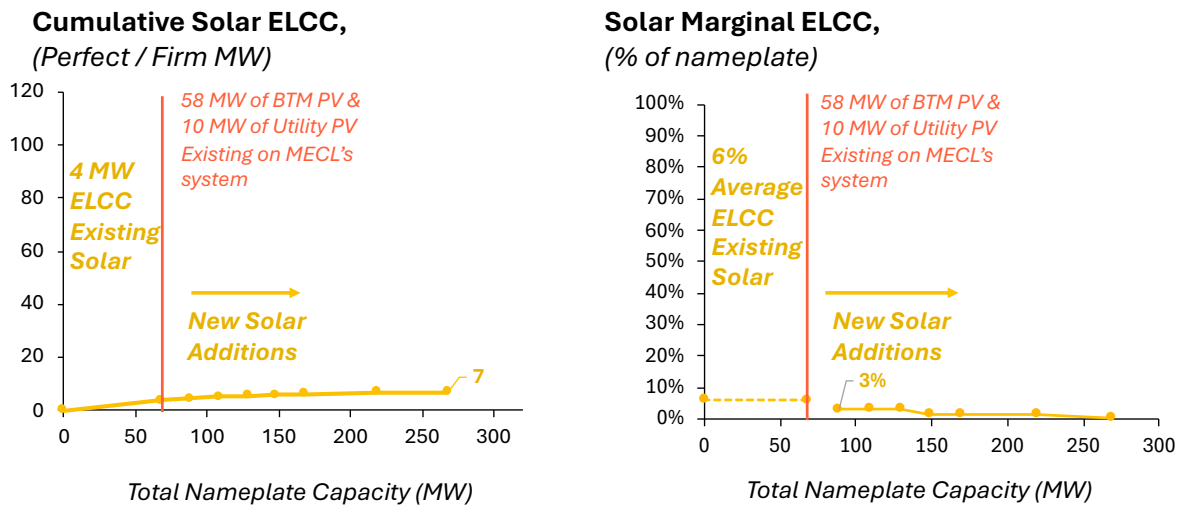
2. **Access to higher capacity factor wind does not meaningfully improve ELCC.** Wind resources that generate more energy do not yield meaningfully higher capacity value if their generation coincides with wind already in the system.

3. **Wind generation cannot fill the entire resource gap.** New wind has very low and declining ELCC values, meaning that thousands of MW would be needed to fill the entire 115 MW resource gap with wind resources alone.

5.3.2 Capacity Value of Incremental Solar Resources

Maritime Electric's 2030 system has 10 MW of utility-scale solar photovoltaic ("PV") resources as well as 58 MW of behind-the-meter solar. Periods of reliability risk in winter are concentrated during early mornings and late evenings, when the ability of solar to produce energy is limited. This limits the reliability contribution of both existing and potential new solar resources. The combined capacity value of the existing 68 MW of solar resources is 4 MW (6%), and the marginal ELCC of utility-scale solar additions is 3%.

Figure 5-6. Cumulative & Marginal ELCC of Standalone Solar



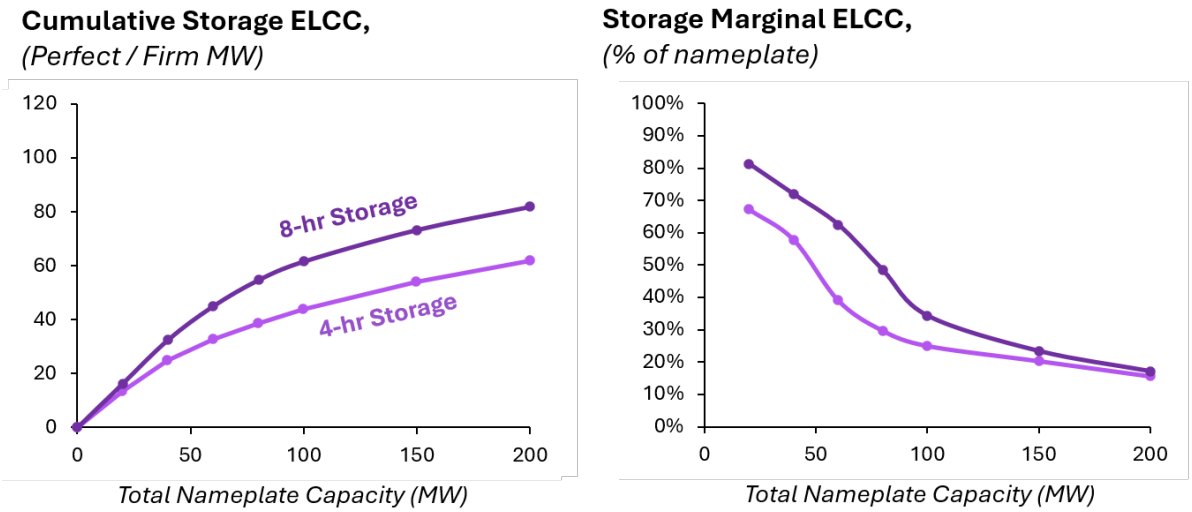
5.3.3 Capacity Value of Energy-limited Resources

Energy-limited resources represent a class of resources that can provide power to a system with a limited amount of energy or duration. This includes battery storage as well as demand response resources that have limitations on how often and for how long they can be called. This study focuses on the incremental capacity value of storage with two different durations - 4-hr and 8-hr - and hypothetical demand response programs. Unlike variable renewable resources, these resources have the benefit of discharging energy or being called upon to reduce load when the system needs it

most. However, the inability to sustain output and need for charging in some cases limit their ability to meet load in all hours.

Energy storage and demand response resources experience diminishing returns as more energy-limited resources are installed. This trend is driven by the flattening of the peak as more batteries are in operation, spreading reliability risk across increasingly long-duration periods of high resource need. Figure 5-7 shows cumulative and marginal ELCC of both 4-hr and 8-hr storage resources.

Figure 5-7. Cumulative and Marginal ELCC of Battery Storage



A few observations can be made pertaining to the ELCC of storage:

1. **Given no existing storage, ELCCs show relatively high values at low penetration,** with a 67% ELCC for the first 20 MW of 4-hr storage and an 81% ELCC for the first 20 MW of 8-hr storage.
2. **Eight-hour storage yields higher cumulative capacity value at higher penetrations** given its ability to address reliability events longer than four hours.

+ **At higher penetrations, storage flattens the net peak, causing risk hours to be elongated and spread out**, leading to saturation and lower marginal ELCCs for both 4- and 8-hr storage.

3. **It would take a very large quantity of storage to fill the entire resource gap,** either 390 MW of 8-hr storage or 540 MW of 4-hr storage, given the marginal ELCCs of both 4- and 8-hour storage decline to under 20% at +200 MW of penetration. These portfolio options are explored in Section 5.3.6.

ELCCs for six different Demand Response programs are also calculated as part of the study, with varying call durations and call limits. The nameplate capacity for all demand response programs was set to 10 MW. Table 5-3 describes the configurations of different programs as well as the capacity value. It should be noted that, because of the dispatch limitations associated with these

hypothetical demand response programs, they have lower value than the existing curtailable load on Maritime Electric's system which can be called at any time with no limitations.

Table 5-3. ELCC of Demand Response Programs

Call Duration (Hours)	Number of Calls per Year	DR Capacity	ELCC (MW)	ELCC (%)
4	18	10	7.6	76%
6	12	10	9.5	95%
8	9	10	9.5	95%
12	6	10	8.3	83%
24	3	10	6.2	62%
72	1	10	2.8	28%

A few observations about Demand Response from the results above:

1. **Demand Response resources, like storage, have a higher incremental capacity value than renewables due to their ability to dispatch.**
2. **The value for demand response is tied to both its duration and number of available calls.** Of all the demand response programs, higher capacity value is tied to the right balance between how long customers can curtail load for and how many times they can be called upon.

Both energy storage and demand response resources can dispatch for limited periods, flattening the diurnal net peak and extending the duration of reliability risk periods. Saturation occurs at higher penetrations of each resource type individually and when they are added in combination, as demonstrated in Table 5-4 below, which shows the cumulative and incremental ELCC of standalone and combined storage and demand response additions.

Table 5-4. ELCC for Demand Response Programs alongside Storage

DR Capacity (MW) *Program with 6 hours duration and 12 calls per year*	4-hour Battery Storage Capacity (MW)	Sum of Standalone ELCCs (MW)	Combined ELCC (MW)	Interactive Effect (MW)
20	0	19.0		
0	20	13.4		
20	20	32.5	27.2	-5.3

5.3.4 Capacity Value of Paired Renewable and Storage Resources

When a portfolio has a diverse set of thermal, variable, and storage resources, studies have shown that the combined capacity value of the portfolio is higher than the sum of the ELCC values of each resource type individually due to positive interactive effects. For this reason, this study computes incremental ELCCs for battery storage combined with solar and wind additions. The groupings of resources were chosen as an exploratory exercise. These are not meant to inform specific

procurement decisions for Maritime Electric but rather show the amount of potential incremental diversity across renewables and storage as well as the implication of saturating capacity value towards meeting larger reliability needs.

When compared to standalone incremental resource additions, some marginal diversity benefits emerge. As Figure 5-8 shows, the initial tranches show similar capacity value and ELCCs. Over 150 MW of storage capacity addition, cumulative ELCC for standalone storage is 54 MW, compared with 56 MW if 100 MW of solar is included and 58 MW if 100 MW of wind is included. Finally, Figure 5-8 compares the cumulative and incremental ELCC of solar, wind, standalone storage, and storage paired with incremental renewables. However, the interactive effects on the Maritime Electric system are very weak, as is typical on winter-peaking systems where loss-of-load risk is driven by heating load and wind and solar resources have very low individual marginal ELCC values.

Figure 5-8. Cumulative & Marginal ELCC of Storage with Wind & Solar

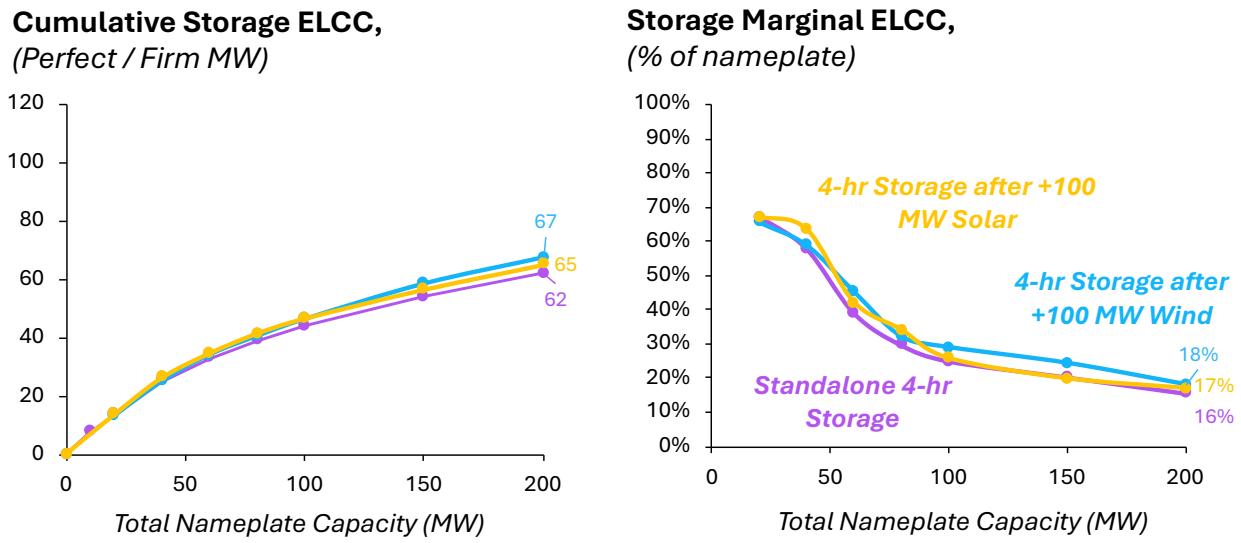


Table 5-5. Capacity Value (MW) & Incremental ELCC (%) by Tranche Size

Capacity Value (Effective MW)	Model Year 2030						
Tranche Size	20	40	60	80	100	150	200
4-hr Storage (Standalone)	13	25	32	38	43	54	61
4-hr Storage with 100 MW Solar	13	26	35	41	46	56	65
4-hr Storage with 100 MW Wind	13	25	34	41	46	58	67
8-hr Storage (Standalone)	16	33	45	55	62	73	83
Wind (Standalone)	1.7	2.8	3.9	4.7	7.0	7.3	7.6

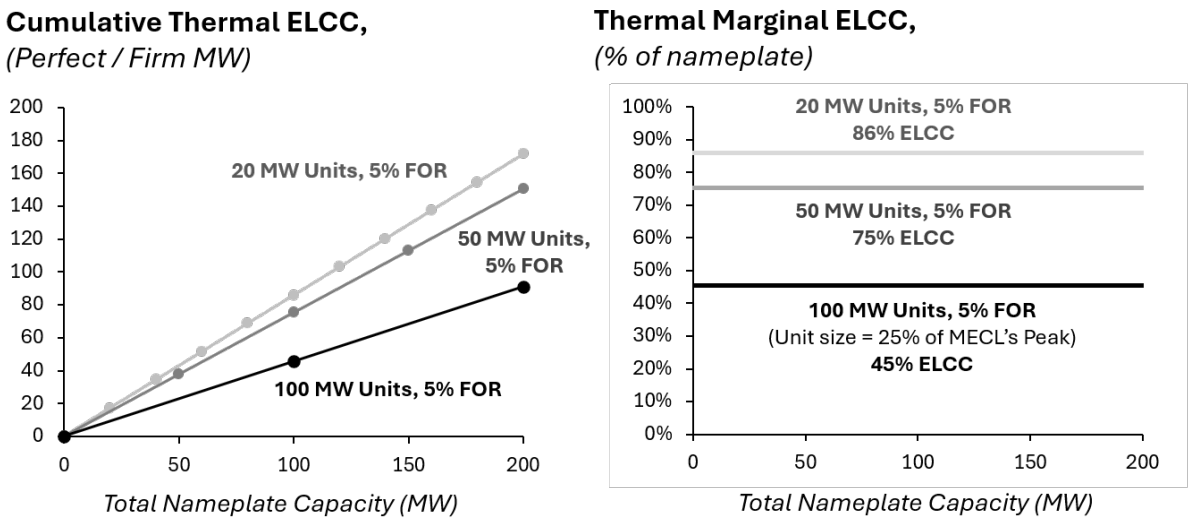
Incremental ELCC (%)	Model Year 2030						
Tranche Size	0-20	20-40	40-60	60-80	80-100	100-150	150-200
4-hr Storage (Standalone)	67%	58%	39%	30%	25%	20%	16%
4-hr Storage with 100 MW Solar	67%	63%	42%	34%	26%	20%	17%
4-hr Storage with 100 MW Wind	66%	59%	45%	32%	29%	24%	18%
8-hr Storage (Standalone)	81%	72%	63%	48%	34%	23%	17%
Wind (Standalone)	8%	8%	5.5%	5.5%	4.2%	3%	1.7%

5.3.5 Capacity Value of Incremental Thermal Units

This study uses the ELCC methodology to assess the capacity value of thermal resources; an emerging best practice being used by an increasing number of utilities and ISOs. This approach captures important outage dynamics which are not captured in ICAP or UCAP thermal accreditation methodologies. Refer to Section 3.1 for an explanation of the ELCC methodology and Section 3.2.4 for the rationale behind thermal resource accreditation.

This study examines thermal capacity value at the unit level. Two key factors drive thermal unit capacity value: (1) unit capacity size and (2) expected forced outage rate. Figure 5-9 shows the cumulative and incremental ELCC for three thermal units with varying unit size but the same FOR of 5%.

Figure 5-9. Cumulative and Marginal ELCC of New Thermal Units of Different Sizes



The results show thermal unit capacity value with varying unit sizes and FORs. The results yield two primary observations:

1. **Thermal resources' capacity value does not exhibit saturation or declining incremental ELCC effects.** This is due to thermal's ability to dispatch whenever loss of load occurs at any length of duration.
2. **Larger unit sizes impact capacity value negatively:** Units with a large unit size show lower ELCCs. This is because Maritime Electric has a small system with a median peak of 393 MW in 2030. A large unit outage by itself is a driver of loss-of-load risk.

These findings show that smaller thermal units offer a more reliable contribution to peak demand and, consequently, have a higher capacity value. Larger-sized units, even with the same forced-outage rates, have lower ELCC values – diverging the most from their ICAP accreditation – since their outages have a larger impact on the system and become more correlated with loss of load risk. This is especially true on a small system like Maritime Electric.

5.3.6 Capacity Value of Combined Thermal and Storage Portfolios

Maritime Electric faces a perfect capacity shortfall of 115 MW in 2030. Different combinations of resources can be used to make up for the shortfall, as long as the effective capacity from those resources covers the shortfall. To illustrate the magnitude of resources that would be needed a combined portfolio value analysis has been carried out using the ELCCs of resources discussed in the sections above.

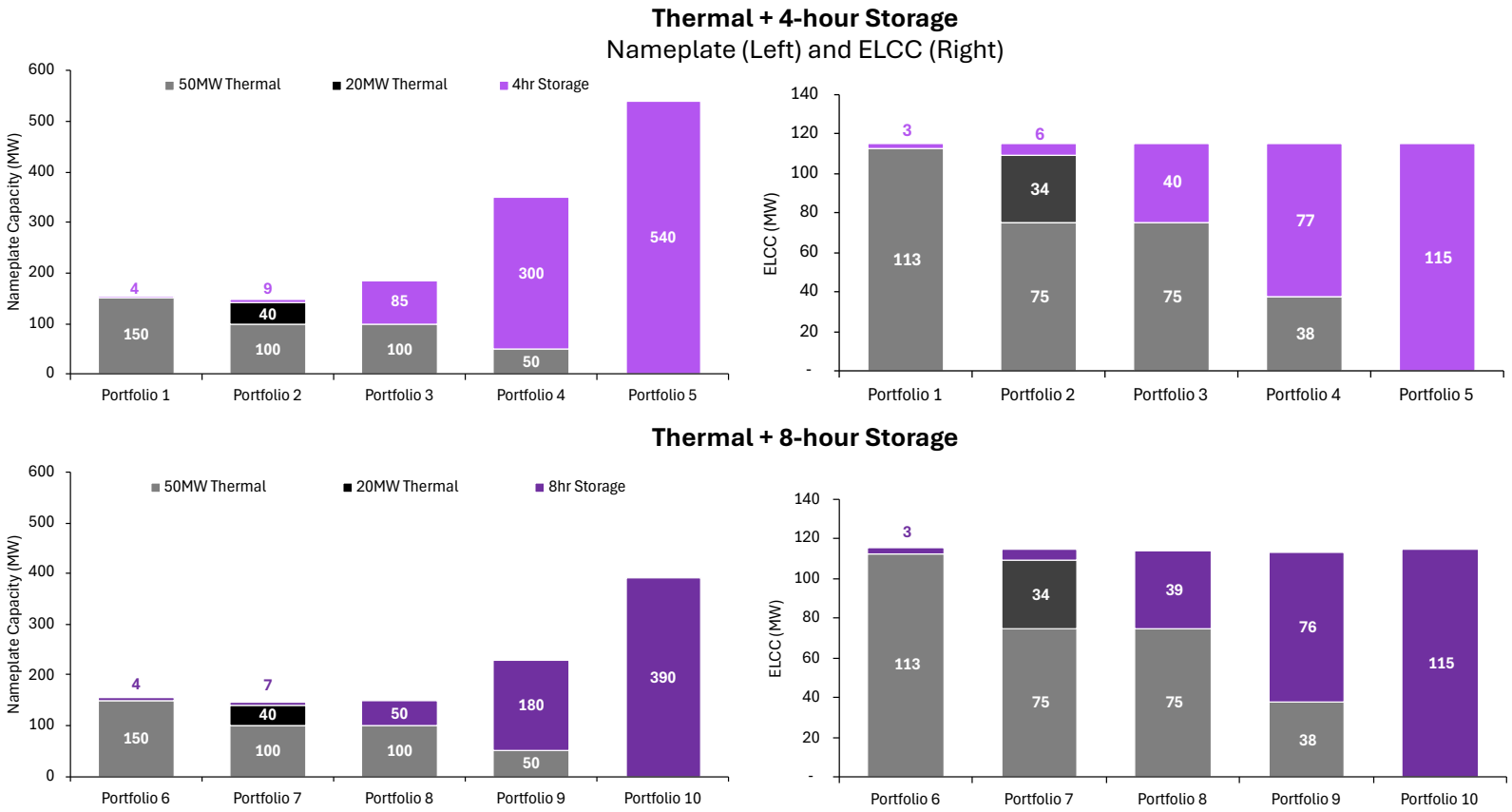
The primary resources being considered for this exploratory analysis are 4-hr and 8-hr storage paired with thermal units sized at 50 MW and 20 MW. Table 5-6 and Figure 5-10 illustrate different combinations of portfolios that would all yield a perfect capacity of 115 MW. Portfolios 1-5 focus on complements of 4-hour storage, while portfolios 6-10 focus on complements of 8-hr storage.

Some portfolios (1, 2, 6, and 7) have a majority of thermal resources and only require a small complement of storage. Other portfolios (3, 4, 8, and 9) have fewer thermal resources and require more perfect capacity to come from storage. Given the saturation of storage ELCCs at higher penetrations, the nameplate capacity needs for covering larger reliability gaps grow substantially. Portfolios 5 and 10 show the buildout of storage needed to cover the full reliability gap, highlighting even further how the saturation of storage ELCCs leads to unreasonable nameplate requirements.

Table 5-6. Combined Thermal and Storage Portfolios

	50 MW Unit-size Thermal (Installed MW)	20 MW Unit-size Thermal (Installed MW)	4-hr Storage (Installed MW)	8-hr Storage (Installed MW)	Total Nameplate (Installed MW)	Combined ELCC (Perfect MW)
Portfolio 1	150	-	4	-	154	115
Portfolio 2	100	40	9	-	149	115
Portfolio 3	100	-	85	-	185	115
Portfolio 4	50	-	300	-	350	115
Portfolio 5	-	-	540	-	540	115
Portfolio 6	150	-	-	4	154	115
Portfolio 7	100	40	-	7	147	115
Portfolio 8	100	-	-	50	150	115
Portfolio 9	50	-	-	180	230	115
Portfolio 10	-	-	-	390	390	115

Figure 5-10. Combined Thermal and Storage Portfolios



6. Conclusion

Maritime Electric is facing significant load growth and will require new capacity to meet growing demand. Maritime Electric's system risk is driven by the coincidence of three factors: extreme cold snaps that can simultaneously limit available wind output and drive heating demand, limited regional resources available for import during those same hours, and the outsized impact of large single-unit outages on a small Island system.

By 2030, Maritime Electric will require 421 MW of equivalent perfect capacity (i.e. the sum of installed capacity rated at its reliability contribution) to meet a one-day-in-ten-years loss of load expectation (0.1 days per year LOLE) standard. The contribution of existing resources and firm contracts provides 306 MW of equivalent perfect capacity, leaving Maritime Electric with a capacity shortfall of 115 MW of equivalent perfect capacity. Absent additional resources, in 2030 the system would be exposed to loss-of-load events with an average frequency of 24 days per year, or 240 times greater than the NPCC reliability target of 0.1 days per year. Without immediate action to close the gap, Maritime Electric would experience loss of load events ranging from 1 hour to over 24 hours in duration during the winter months.

Off-Island resources can close some of the 115 MW shortfall if additional firm capacity becomes available. While non-firm purchases offer energy when available, reliance on non-firm imports during cold snaps poses risk in meeting Maritime Electric's customer demand. Regardless of whether imports are firm or non-firm, only 50 MW of transmission headroom remains, meaning only some of the 2030 shortfall can be met through off-Island resources even if available.

The effectiveness of on-Island options varies widely by resource type. This study quantifies the capacity value of new resource options using the ELCC method. Additional wind resources have an ELCC of 8% of nameplate capacity, reflecting the preponderance of critical reliability periods that are driven by low wind generation during times of winter peak load. Energy-limited resources, such as 4-hour storage, can reach as much as 67% ELCC at low penetrations but would saturate significantly as 100 MW or more of nameplate capacity is deployed. While longer 8-hour duration storage has a higher initial ELCC of 81%, it too saturates at higher penetrations. This saturation effect occurs as storage flattens short-duration peaks in net load, leaving longer-duration periods of reliability risk that are too long to be fully addressed by another storage resource of the same duration. Firm generators remain the most effective source of capacity, yet large units fall short of 100% ELCC. When considering both unit size and forced-outage rate, 50 MW thermal units can provide 75% ELCC. Meeting the need cost-effectively will require a portfolio that balances individual resource capacity values and the investment and operational costs expected from those same resources.

6.1 This Study Brings Maritime Electric's Resource Adequacy Planning Processes Into Alignment with Industry Best Practices

This study utilizes industry best practices for resource adequacy need determination and resource accreditation. These include:

- **Model and Data: Loss of Load Probability (LOLP) modeling and robust multi-weather dataset.** With both a LOLP model and a robust dataset, Maritime Electric's planners can develop least-cost plans tuned to the unique reliability characteristics of the Maritime Electric system. As customer adoption of electrified heating grows, continuing to deliver reliable electric service to keep PEI homes heated will be increasingly important.
- **Resource Accreditation: accredit all resources based on their marginal contributions to resource adequacy.** Accrediting all resources relative to a perfect capacity benchmark using the ELCC methodology ensures all resources are measured on a level-playing field. ELCC captures each resource's unique ability to improve reliability, considering factors such as derates associated with conventional thermal outages, variability in wind and solar output, energy storage limitations of battery energy storage systems, or demand response call limitation that can limit their availability during critical periods. Marginal ELCC accreditation supports Maritime Electric's ability to identify the most cost-effective portfolio of resources to meet the system's reliability needs.

A detailed comparison between Maritime Electric's prior practices and the best practices within this study is provided in Table 6-1. These improvements are based on best practices in E3's extensive professional experience as well as a detailed survey of practices across regional jurisdictions – that survey is presented in Appendix A

Table 6-1. Updated Maritime Electric's Resource Adequacy Planning Processes

Key Parts of a RA Framework	Components	Maritime Electric Previous Practice	Assessment of Previous Practice	Practices Implemented in This Study
Part 1 Model + Data Development	LOLP model evaluating all hours under broad range of weather conditions	Deterministic annual peak forecast; single design temperature; no LOLP model	**Partial Gap —No Maritime Electric-LOLP model, but relies on NPCC**	**No Gap – Industry-standard LOLP model used (RECAP)**
	Robust load and resource dataset with weather scenarios	Hourly operational data maintained; load forecast updated annually	**Partial Gap — Data exists but not in LOLP framework**	**No Gap – 40+ years of load and weather**
Part 2 Need Determination	Target reliability standard	NPCC 1-in-10 LOLE standard	**No Gap**	
	Total reliability need or PRM based on load & weather variability	15% planning reserve not independently modeled by Maritime Electric	**Partial Gap — PRM adopted based on NPCC analysis**	**No Gap –PRM calculated based on reliability target and LOLP model**
	Operating reserve obligations	Reserves obligations captured under Maritimes Area OATT	**No Gap — Operating reserves maintained**	
Part 3 Resource Accreditation	ELCC for wind	LOLE-based wind ELCC with declining curve for higher penetration (23% for 92 MW fleet)	**Partial Gap — Wind ELCC methodology in place; calculated using a limited LOLP analysis**	**No Gap – All resources accredited using an ELCC methodology using an industry-standard LOLP model**
	ELCC for utility-scale or behind-the-meter solar	ELCC methodology exists; Solar identified as zero capacity value	**Partial Gap —ELCC methodology in place; not applied to solar**	
	ELCC for energy-limited resources (e.g. storage or demand response)	No PEI-specific probabilistic analysis/methodology	**Gap — No Storage or Demand Response ELCCs specific to Maritime Electric**	
	ELCC for thermal resources	CT/RICE credited at nameplate (ELCC = 1.0); no EFORd adjustment applied	**Gap — No Thermal ELCC specific to Maritime Electric**	
	Accreditation of transmission/imports	NBEM firm imports accredited; no probabilistic availability adjustment	**Partial Gap— Firm imports considered, but non-firm imports are not currently accredited to contribute to RA**	

6.2 Recommendations for Maritime Electric

6.2.1 Accelerate procurement of new resources to close the resource adequacy gap, prioritizing resources with high capacity value

Maritime Electric has an urgent need for new resources. Absent additional resources, Maritime Electric's system would be exposed to an average of 24 loss-of-load events per year by 2030. With long lead-times for procurement, permitting, construction, and interconnection of new resources, immediate action will be needed to ensure Maritime Electric can meet NPCC standards for resource adequacy. Given the size and urgency of the need, Maritime Electric should prioritize resources with relatively high capacity value.

While solar, wind, storage, and demand response resources can provide some incremental capacity value, additional thermal is also needed to close Maritime Electric's growing capacity shortfall. The quantity of new capacity needed represents 25% of Maritime Electric's total capacity need by 2030. Thermal firm resources provide the highest capacity value solutions. Storage can also provide high value, but its ELCC is contingent on availability of energy to charge from and decreases significantly as storage penetration increases. Wind and solar alone cannot be depended on to meet load during long critical periods. Prioritizing new thermal firm capacity therefore both anchors near-term reliability and unlocks the reliability contribution of the wind and storage resources procured alongside it.

6.2.2 Use the results from this study to inform least-cost and reliable portfolios in future economic analyses

This study establishes the magnitude of Maritime Electric's near-term capacity need and the reliability contribution of new resource options, but it does not evaluate the relative cost of the portfolios that could meet that need. E3 recommends Maritime Electric to perform an economic analysis to account for both the capital cost of new resources and their operating costs, to evaluate the portfolio that meets the reliability need at least cost. For the purposes of near-term procurement, performing a net-present value analysis across available candidate resources paired with the capacity value results from this study provides the necessary results to help Maritime Electric identify the best combinations to meet reliability at least cost.

Addressing the near-term shortfall and maintaining Maritime Electric's system reliability requires immediate action. Absent additional resources, by 2030 the system would be exposed to loss-of-load events on an average of 24 days per year. New capacity carries long lead times for procurement, permitting, construction, and interconnection - meaning the resources available in 2030 depend on decisions made now.

The capacity value of variable resources and battery energy storage saturates, and their ELCCs are contingent on sufficient firm thermal capacity being in place to complement and cover the rest of the long-duration critical periods that renewables and storage alone cannot serve. Prioritizing firm

thermal capacity therefore both anchors near-term reliability and unlocks the reliability contribution of the wind, solar, and storage resources procured alongside it.

6.2.3 Evaluate whether additional on-Island capacity is needed for resilience

Maritime Electric's challenge extends beyond planning for conventional resource adequacy events. While not needed for near-term procurement decisions, Maritime Electric's planners should consider the value of existing and new resources in preparing for resilience events such as a full grid disconnection from New Brunswick. Maritime Electric should ensure it has sufficient resources to anticipate, respond to, and recover from unpredictable events and systemic shocks to the electricity system, including extreme weather events. As electrification of space heating continues to push winter demand into closer alignment with the system's critical periods, the consequences of an extended event where the Island system is disconnected grow in severity. PEI therefore faces both a reliability and a resilience challenge.

This resource adequacy study assumes full availability of subsea cables, when in reality, there is a non-zero likelihood that they could experience failures that would impact Maritime Electric's access to power from NBEM and the Point Lepreau Nuclear Generating Station. The Island is fully dependent on these cables, and the reliability need and ELCCs quantified in this report are determined on the premise that they remain in service. For this reason, E3 recommends that Maritime Electric undertake an additional resilience analysis to understand what such a failure would do to the system and what would constitute an acceptable level of performance during the event, given it would carry serious consequences for Island residents.

This resiliency evaluation would not measure the islanded system against the one-day-in-ten-years resource adequacy requirement, given some loss of load would be expected under such extreme conditions. Instead, the study would identify the minimum acceptable performance during an extended event, and the resources needed to provide it. For example, one useful criterion is the minimum amount of capacity and generation needed for Maritime Electric to implement rotating outages while serving all critical loads. The study may identify the need for *additional* thermal capacity, relative to the RA need determined in this study.

Appendix A. Jurisdictional Scan

A.1 Jurisdictional Scan of Resource Adequacy Practices

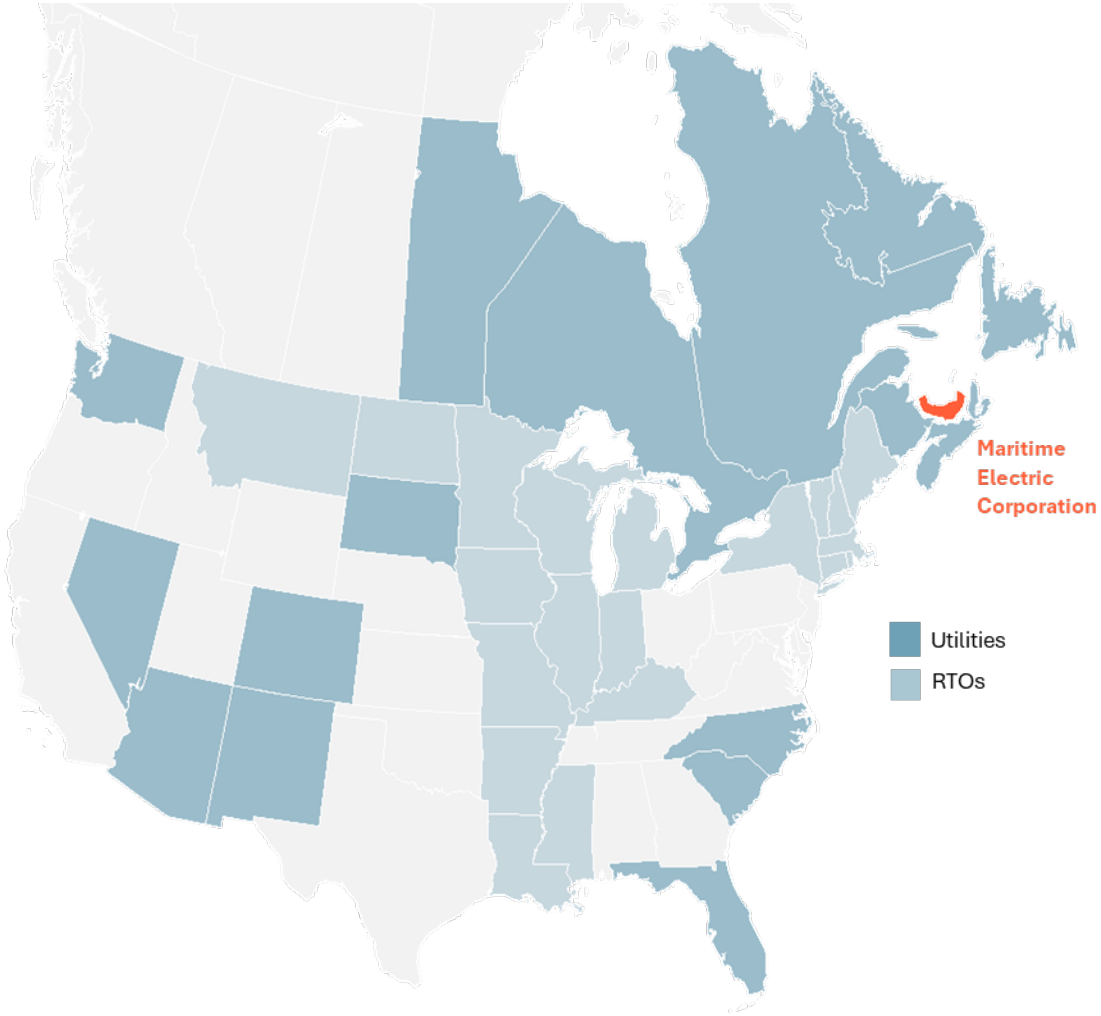
To contextualize this Resource Adequacy (RA) study's approach, E3 performed a jurisdictional scan of RA planning processes and associated frameworks in identifying a system planning process that is supported by industry best practices. This survey was carried out across North American jurisdictions identifying how each entity approaches their resource adequacy planning and highlights gaps relative to established best practices.

This survey aimed to capture a variety of planning practices with a range of geographies, markets, structures and methods around North America. The list of evaluated jurisdictions can be seen below:

- Maritime Electric
- New Brunswick Power
- Nova Scotia Power
- Manitoba Hydro
- Newfoundland Hydro
- Hydro Quebec
- Ontario Independent Electricity System Operator (IESO)
- Arizona Public Service
- El Paso Electric
- Avista Corporation
- NorthWestern Energy
- NV Energy
- Portland General Electric
- Black Hills Energy - Colorado
- Puget Sound Energy
- Dominion Energy South Carolina
- Duke Energy Carolinas
- Florida Power and Light
- ISO New England (ISO-NE)
- New York ISO (NYISO)
- Midcontinent ISO (MISO)
- PJM Interconnection LLC (PJM)

For this analysis, E3 uses three key topics, each contributing to a comprehensive understanding of the industry's current practices in Resource Adequacy Planning. The categories explore how entities use different (1) Loss of Load Probability (LOLP) models, (2) need determination methodologies, and (3) resource accreditation.

Figure A-1. Jurisdictions Reviewed for Maritime Electric RA Study



A.2 Resource Adequacy Model

A resource adequacy analysis that adheres to best practices outlined in this report starts with a model with the appropriate features to assess system RA. Table A-1 below is a summary of the RA models used by each entity identified to perform their RA analysis as part of their resource planning process. The whitepaper linked in Appendix B.1 covers the requirements of a robust RA model in more detail.

Table A-1. Resource Adequacy Model Summary

	Utility/Jurisdiction	Software Provider	Software
Northeast Canadian Utilities	Maritime Electric [This Study]	E3	RECAP
	New Brunswick Power	E3	RECAP
	Nova Scotia Power, Inc.	E3	RECAP
	Manitoba Hydro	General Electric	PlanOS (formerly GE-MARS)
	Newfoundland Hydro	E3	RECAP
	Hydro-Quebec	General Electric	PlanOS (formerly GE-MARS)
	IESO (Ontario)	General Electric	PlanOS (formerly GE-MARS)
Southwest Utilities	Arizona Public Service Co	PowerGEM	SERVM
	El Paso Electric Co	E3	RECAP
Other Western Utilities	Avista Corporation	Avista Corporation	AVAM (Excel-based)
	NorthWestern Energy	N/A	N/A
	NV Energy	E3	RECAP
	Portland General Electric	Portland General Electric	Sequoia
	Black Hills Energy - Colorado	E3	RECAP
	Puget Sound Energy	E3	RECAP
Eastern Utilities	Dominion Energy South Carolina	PowerGEM	SERVM
	Duke Energy Carolinas	PowerGEM	SERVM
	Florida Power and Light	E3	RECAP
RTOs	ISO New England	General Electric	PlanOS (formerly GE-MARS)
	New York ISO	General Electric	PlanOS (formerly GE-MARS)
	Midcontinent ISO	PowerGEM	SERVM
	PJM	PJM	PRISM

A.3 Need Determination

One of the most fundamental outcomes of a Resource Adequacy analysis is the system's Need Determination. This establishes how much capacity is needed across the pool to meet a resource adequacy standard. As such, it is very important to establish a resource adequacy metric that will ensure system reliability within the given constraints. The table below summarizes the Need Determination framework employed by various jurisdictions across North America. This includes their preferred resource adequacy metric and a statistical standard to solve for. One of the most common industry standards today is the "one day in ten years" or "0.1 days per year". This need determination process is then carried out at different frequencies across jurisdictions.

Table A-2. Need Determination Summary

	Utility/Jurisdiction	PRM Framework	Resource Adequacy Metric	Current Standard
Northeast Canadian Entities	Maritime Electric [historical]	15% ICAP*	LOLE	0.1 days per year
	Maritime Electric [this study]	**7.1% PCAP**	**LOLE**	**0.1 days per year**
	New Brunswick Power	20% ICAP*	LOLE	0.1 days per year
	Nova Scotia Power, Inc.	20% UCAP*	LOLE	0.1 days per year
	Manitoba Hydro	Historical PRM of 12%	LOLE	0.1 days per year
	Newfoundland Hydro	UCAP	LOLH	2.8 hours per year
	Hydro-Quebec	UCAP	LOLH	2.4 hours per year
	IESO (Ontario)	PCAP (seasonal)	LOLE	0.1 days per year *(seasonal specific standards add up to 0.1 days per year)*
Southwest Utilities	Arizona Public Service Co	UCAP	LOLE	0.1 days per year
	El Paso Electric Co	PCAP	LOLE	0.1 days per year
Other Western Utilities	Avista Corporation	ICAP	aLOLP /LOLE	5% per year + 0.1 days per year
	NorthWestern Energy	UCAP	LOLE	0.1 days per year
	Nevada Power Company	UCAP	LOLE	0.1 days per year
	Portland General Electric	UCAP	LOLH	2.4 hours per year
	Black Hills Energy - Colorado	UCAP	LOLE	0.1 days per year
	Puget Sound Energy	PCAP	LOLE	0.1 days per year
Eastern Utilities	Dominion Energy South Carolina	UCAP	LOLE	0.1 days per year
	Duke Energy Carolinas	UCAP	LOLE	0.1 days per year
	Florida Power and Light	ICAP	LOLP	0.1 days per year
RTOs & Resource Adequacy Programs	ISO New England	ICAP (seasonal)	LOLE	0.1 days per year
	New York ISO	UCAP	LOLE	0.1 days per year
	Midcontinent ISO	UCAP	LOLE	0.1 days per year
	PJM	UCAP	LOLE	0.1 days per year

** Specific PRMs are calculated by NERC-NPCC, not by the entities directly*

A.4 Resource Accreditation

Most markets and systems, including entities in the Atlantic provinces, already use ELCC accreditation for at least one technology, and most others are in the process of transitioning towards ELCC or are actively considering its implementation. The table below summarizes the current status

and framework of ELCC across the various organized capacity markets and resource adequacy programs throughout North America.

While most uses of ELCC to date have focused on renewables (and, to a lesser extent, energy storage), the conceptual framework is broadly applicable to all resource types. No resource is perfect, but all resources' contribution to reliability can be measured using an ELCC framework. The application of ELCC for resource accreditation across all types of resources provides the strongest foundation for a robust resource adequacy planning framework.

Table A-3. Resource Accreditation Summary

	Utility/Jurisdiction	Resource Accreditation Framework
Northeast Canadian Entities	**Maritime Electric [historical]**	+ ELCC for renewable resources (wind, solar) + Proposed ELCC methodology for storage and demand response in their next capacity value study + ICAP for thermal
	Maritime Electric [this study]	+ ELCC for renewable resources, thermal resources, and energy limited resources
	New Brunswick Power	+ Variable resources are assigned a seasonal partial credit for their firm capacity contribution + UCAP for thermal
	Nova Scotia Power, Inc.	+ ELCC for solar + UCAP for thermal
	Manitoba Hydro	+ Solar and Wind: Power output during Winter Peak Load + Thermal: Power output during Winter Peak Load
	Newfoundland Hydro	+ ELCC for Solar, Storage and Wind + ICAP for Thermal
	Hydro-Quebec	+ ELCC for Wind + UCAP for Thermal
	IESO (Ontario)	+ Firm capacity for Solar and Wind + ELCC for Storage + UCAP for Thermal
Southwest Utilities	**Arizona Public Service Co**	+ ELCC for solar, storage, wind, and demand response + UCAP for thermal (expects to move to ELCC for 2026)
	El Paso Electric Co	+ Currently using ELCC methods to value capacity from all resources, including renewables, storage, and firm in 2021 IRP
Other Western Utilities	**Avista Corporation**	+ Qualifying Capacity Credits (QCC) for solar, wind, storage and DR + ICAP for thermal
	NorthWestern Energy	+ ELCC for dispatch limited resources (solar, storage and wind)
	Nevada Power Company	+ Adopted ELCC method for valuing renewables in Fourth Amendment to 2018 Joint Triennial Integrated Resource Plan (2020) + UCAP for thermal
	Portland General Electric	+ Currently using ELCC methods to measure capacity value of renewables and storage resources in IRP planning + Using UCAP accounting for thermal resources

	Black Hills Energy - Colorado	+ ELCC for dispatch limited resources (solar, storage and wind) + ICAP for thermal
	Puget Sound Energy	+ ELCC for solar, wind, storage and demand response + ELCC for new generic thermal, ICAP for existing thermal
Eastern Utilities	**Dominion Energy South Carolina**	+ ELCC methodology for solar and storage + Using UCAP accounting for thermal resources
	Duke Energy Carolinas	+ ELCC for dispatch limited resources (solar, storage and wind) + Using UCAP accounting for thermal resources
	Florida Power and Light	+ Firm capacity value calculated for summer and winter peak hours depending on site location, technology, design, and the total amount of solar that is operating on FPL's system
RTOs & Resource Adequacy Programs	**New York ISO**	+ ELCC for solar, storage and wind + UCAP for thermal (EFORd-based)
	Midcontinent ISO	+ DLOL + UCAP for thermal (EFORd-based)
	PJM	+ Average ELCC for wind, solar and storage + UCAP for thermal (EFORd-based) + Marginal ELCC for all resources

Appendix B. Resource Adequacy Framework & Critical Periods

B.1 Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets

Electricity systems are under increasing stress related to resource adequacy. Unprecedented load growth, changes in historical weather patterns, retirement of conventional resources, and the rise of variable and energy-limited resources have created new challenges for maintaining resource adequacy. At the same time, recent events have shown that conventional thermal generators often underperform during critical winter conditions. In this context, power system planners and market operators are reevaluating longstanding practices for determining and allocating resource adequacy need. E3's white paper, Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets, describes these challenges and lays out a framework that both formalizes and advances the emerging methodologies for evaluating resource adequacy need.

The paper formalizes a framework for resource adequacy that builds on established methodologies like loss-of-load probability and Effective Load Carrying Capability (ELCC). It provides a more precise mathematical formulation of the problem than has previously been put forward, helping to clarify how total system need is defined, how resources are accredited, and how obligations are allocated.

Download the full white paper here

B.2 A Critical Periods Framework

Ensuring resource adequacy for a future electric system under higher penetrations of variable energy and energy-limited resources hinges on the ability to design the system to perform under the most constrained conditions – whenever they may occur. These are "critical periods": periods when the electricity system has reached or exceeded its maximum limits to serve electricity demand, meaning that loss of load has already occurred, is occurring, or is imminent. From this definition, it naturally follows that during critical periods, any additional generation or load reduction would improve system reliability. Designing the system to perform during these critical periods has always been the primary challenge of resource adequacy. Historically, those critical periods coincided almost exclusively with peak load, but in the future, critical periods will increasingly occur at different times of day and year due to combinations of high load and low resource availability.

The robust framework for resource adequacy requires three components:

1. Development of a **loss-of-load-probability (LOLP) model** that can simulate the availability of loads and resources on an hourly basis across a wide variety of weather

conditions to identify periods in which an electricity system is vulnerable to reliability risks;

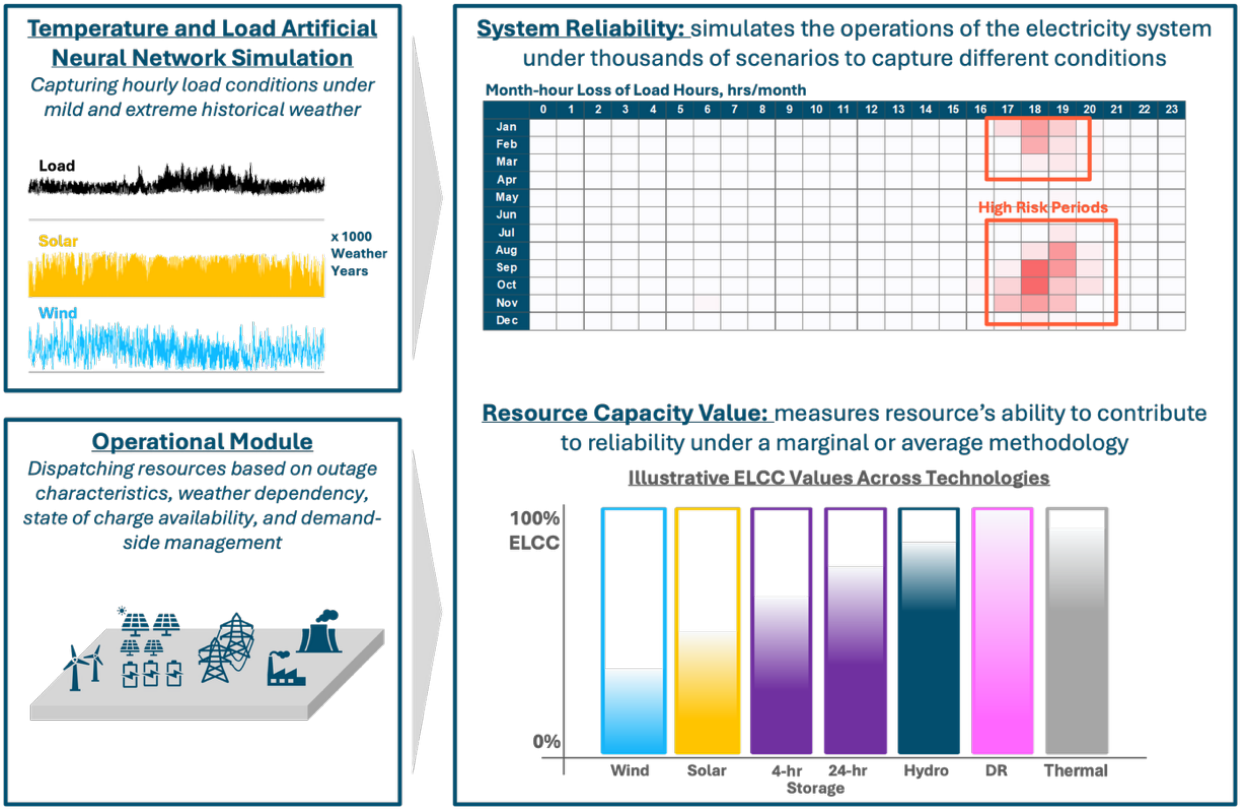
2. Derivation of a **total reliability need (TRN)** that reflects the amount of "perfect capacity" needed to achieve an acceptable standard of reliability, which will ultimately inform a target planning reserve margin (PRM); and
3. Application of an **effective load carrying capability (ELCC)** accounting framework to measure the contribution of each resource (or portfolio of resources) towards the total capacity requirement. Under a critical period framework, ELCC will be determined on a marginal basis (marginal ELCC), which can also be understood as representing its expected performance during critical periods. The use of marginal accreditation is important to ensure efficient capital investment by accurately capturing the marginal value of additional resource investments.

B.3 Model + Data Development

Modern resource adequacy analysis is grounded in models with capabilities of capturing the increasing complexity of modern power systems. In addition to the conventional complexities of thermal outages, higher penetrations of variable and energy-limited resources have driven the growing adoption of Monte Carlo–based loss-of-load-probability (LOLP) models.

Planners use LOLP models to simulate thousands of years of plausible system conditions to calculate statistically significant system reliability metrics and individual resource contributions to system reliability. These conditions include load variability, weather variability, renewable output variability, and forced outage events. To capture these conditions, LOLP models require robust inputs to replicate operations of each unique system. The following section describes the dataset in more detail and Section 4 describes the inputs specific to this study.

Figure B-1. Loss-of-load-probability (LOLP) Modeling Framework and Selected Inputs and Outputs



B.3.1 Developing a Data Set for LOLP Modeling

All LOLP models require a dataset with robust assumptions and inputs to reflect the range of plausible system states that may pose reliability challenges to the system. This includes:

1. **Distributions of extreme weather events:** While planners have long relied on extended samples of historical weather data to inform probability distributions of extreme weather events, the assumption that historical conditions provide an accurate representation of the future may no longer be appropriate.
2. **Hourly load and renewable production data:** the adequacy of a system will depend, in part, on how renewables perform during rare extreme load events. This utilizes historical generation profiles, as available, complemented by simulated renewable profiles, which rely on historical meteorological data as inputs into simulations of wind and solar plant performance, per common practice.
3. **Performance assumptions for existing and emerging technologies:** generation technologies are quickly advancing, and electricity systems are presented with new resource options to meet their needs that would not have been available a decade ago. This trend is likely to continue, as research, development, and deployment will continue to bring new technologies into the market. While these advances offer long-term promise, planners

should also take caution in assumptions made regarding the performance of new resources with limited operational history on a commercial scale. Especially during early years of commercialization, new technologies may not perform as expected.

+ **Randomness and correlations among unit outages:** the assumption that forced outages of generators can be modeled as independent, uncorrelated events is common practice in traditional LOLP modeling; to the extent that underlying factors like weather patterns and fuel supply issues may affect outages at multiple plants simultaneously, a correlated risk that is not often captured may exist. While evidence of this type of correlated relationship exists, it is typically highly geographically specific and difficult to generalize. While capturing these types of relationships would improve the rigorousness of reliability modeling, how to use the limited availability of robust data sets that inform this factor is an emerging area of research within the field.

B.3.2 Key Model Outputs

The simulation of conditions across a broad range of conditions allows LOLP models to calculate a variety of output metrics that generally fall into two categories:

+ **Direct statistical measures of resource adequacy.** These metrics provide insights into the expected frequency, size, and duration of expected unserved energy events based on the results of the simulation of thousands of years; among these, the most commonly utilized is **Loss of Load Expectation (LOLE)**, defined by the North American Electric Reliability Corporation (NERC) as "the expected number of days per time period (usually a year) for which the available generation capacity is insufficient to serve the demand at least once per day."[28] It should be noted in this metric that any day with any amount of loss of load counts as "one" day whether it is a one hour or twenty hour loss of load event.

+ **Capacity accounting metrics.** These metrics are useful in the application of a PRM accounting scheme to account for a system's resource adequacy needs and can be derived through iterative LOLP analysis.

[28] NERC, "Probabilistic Adequacy and Measures: Technical Reference Report." https://www.nerc.com/comm/PC/Probabilistic%20Assessment%20Working%20Group%20PAWG%20%20Relat/Probabilistic%20Adequacy%20and%20Measures%20Report.pdf

Table B-1. Typical LOLP Model Outputs

Metric Type	Metric	Type (Units)	Definition
Direct Statistical Measures of Resource Adequacy	Loss of Load Expectation (LOLE)	Event Frequency (days per year)	Average number of days per year in which unserved energy occurs due to system demand exceeding available generating capacity
	Expected Unserved Energy (EUE)	Event Magnitude (MWh per year)	Average total quantity of unserved energy (MWh) over a year due to system demand exceeding available generating capacity
	Normalized EUE (nEUE)	Event Magnitude (parts per million)	Expected unserved energy normalized by total expected annual demand
	Loss of Load Hours (LOLH)	Event Duration (hours per year)	Average number of hours per year with loss of load due to system demand exceeding available generating capacity
Capacity Accounting Metrics	Planning Reserve Margin (PRM)	System capacity need (MW)	Total amount of accredited capacity needed to meet a pre-defined reliability target, expressed as a ratio relative to the median system peak demand
	Effective Load Carrying Capability (ELCC)	Resource accreditation (MW)	Capacity credits assigned to individual resources (or groups of resources) for the purposes of their contribution to the PRM

B.4 Need Determination

The first phase of any resource adequacy assessment is the determination of need, or the total requirement necessary to maintain a target standard for resource adequacy. Traditionally, entities procure sufficient resources to meet a planning reserve margin (PRM) to ensure system adequacy. In modern resource adequacy planning practices, the PRM is a derivative metric based on the total MW needed to meet the reliability metrics.

The relationship between capacity shortfall and LOLE is asymmetric and non-linear, which means an increasing capacity shortfall below the desired standard quickly escalates to rapid degradation of the portfolio's reliability.

B.4.1 Using the Target Reliability Standard to Calculate a Target PRM

For many entities, the PRM requirement is calibrated to meet a reliability standard (e.g. LOLE standard of 0.1 days per year, or, more commonly, the "one-day-in-ten-year" standard). The standard is intended to ensure that loss-of-load events resulting from insufficient generation occur very rarely. Despite the absence of a uniform standard for resource adequacy, many entities use a

0.1 LOLE standard, and this standard continues to be widely used as the basis for resource adequacy planning by utilities and RTOs alike. See Appendix A for a survey of reliability targets used across a range of utilities and markets.

To calibrate the planning reserve margin, the total MW requirement is calculated using a LOLP model. This requirement in MW is calculated by adding capacity to the system until the achieved level of reliability is equal to its reliability target (e.g. 0.1 LOLE). Then, the PRM can be calculated by dividing this value by the median peak load of the system in MW and subtracting one. In this construct, a positive PRM value will emerge because 1) the system requires capacity for the 50% of years that have peak loads higher than the median peak load and, if applicable, 2) the system requires operating reserves to be held in real-time above and beyond generation being used to serve load.

While the 0.1 LOLE standard has gained near-universal adoption among utilities and program administrators across North America, some industry observers have argued that additional reliability metrics should be considered in setting standards that focus on the duration (e.g. loss-of-load-hours) and magnitude (e.g., expected unserved energy) of loss of load events. However, consideration of alternative reliability metrics is beyond the scope of this report. Nonetheless, proper application of the 0.1 LOLE standard is sufficient to achieve the intended objective of ensuring that reliability events due to insufficient supply are exceedingly rare.

B.4.2 Transition to a PRM with ELCC Accounting for All Resources

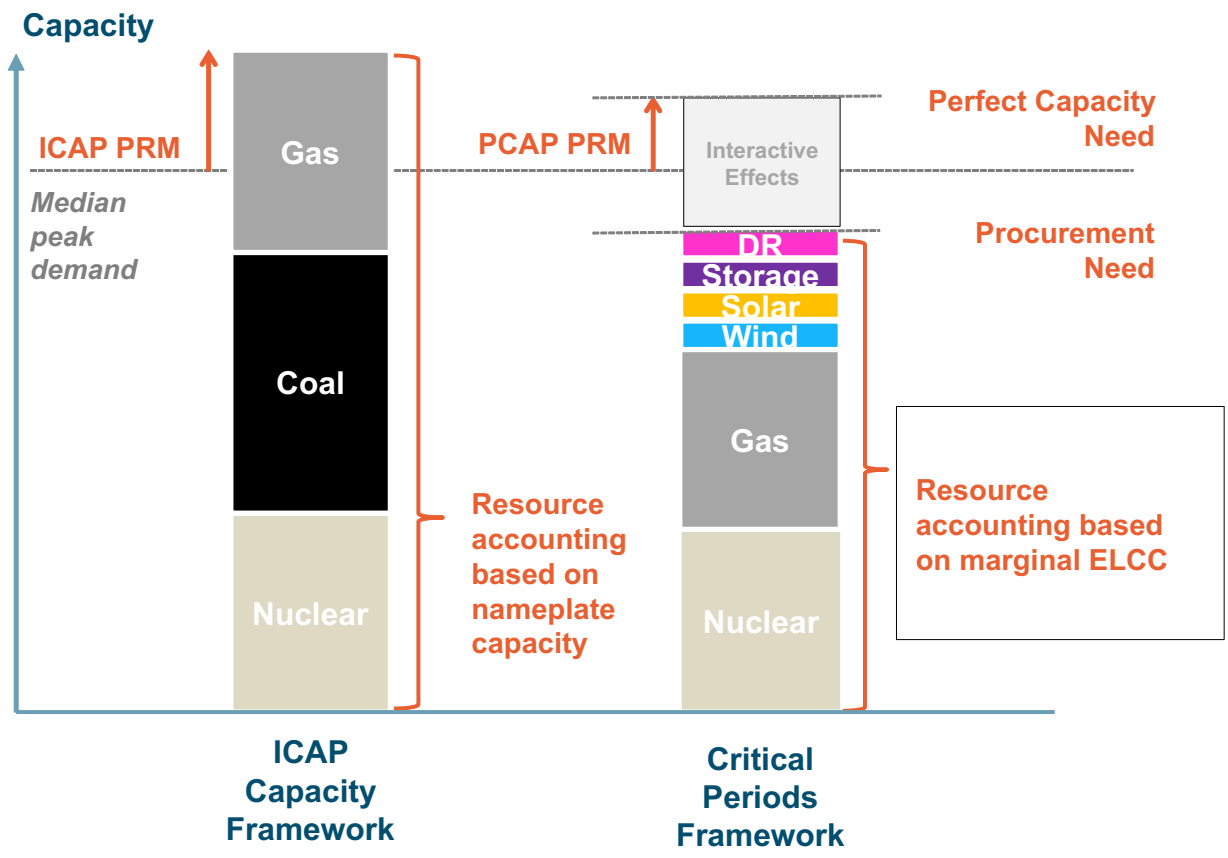
In traditional systems with mostly conventional thermal resources, planners could simply sum up the installed capacity and ensure sufficient MW to meet the PRM. However, no resource, including conventional thermal resources, is perfect. Due to plant outages (both forced and planned), resources are often not available at their installed capacity, and so such a convention required increasing the PRM requirement to account for the fact that not all resources would be available when needed. This same logic is applied to variable and energy-limited resources like wind and storage. Simply summing the installed capacity of variable and energy-limited resources could and would overestimate their contribution to meeting system reliability.

Modern resource adequacy practices quantify the required quantity of perfect capacity necessary to achieve the 0.1 LOLE reliability standard. This represents a change from the accounting convention that many utilities have historically used. The transition to an ELCC PRM accounting framework is being increasingly utilized across the industry as utilities and ISOs recognize the benefits of improved alignment between the resource requirement and the quantification of all resources to contribute to this requirement on an apples-to-apples basis. The next section describes the ELCC approach and its relationship to perfect capacity in more detail.

To ensure consistency with the *perfect capacity* PRM requirement, resources should be accredited under this framework not based on their installed capacity but rather their *equivalent perfect capacity* which is precisely what ELCC values represent. Figure B-2 illustrates these two approaches to PRM accounting. Note that both accounting paradigms represent the same system, and both achieve the same level of reliability. The choice to shift to ELCC accounting for all resources is primarily motivated by the desire to ensure consistent valuation of the reliability contributions

across all resource types. The PRM requirements from this study reflect the ELCC accounting convention.

Figure B-2. Installed Capacity (ICAP) vs Critical Periods (PCAP) Accounting Convention



B.5 Resource Accreditation

Within this modern resource adequacy framework, the capacity value assigned to each resource (or portfolio of resources) is determined using an effective load carrying capability (ELCC) methodology, which relies on the same LOLP modeling techniques to determine the amount of perfect capacity that provides an equivalent value to system reliability. Properly applied, an ELCC-based framework for capacity accreditation naturally accounts for the oft-cited complications that arise as high levels of renewables are integrated, including the "shift to the net peak," the need to account for energy sufficiency as well as capacity, and the saturation effects and diversity benefits that accrue to portfolios of variable and energy-limited resources. ELCC is therefore broadly viewed as the cornerstone of a robust approach to capacity accreditation and has quickly gained widespread usage within the industry.

The ELCC method has emerged as the preferred metric for capacity accounting to meet resource adequacy for multiple reasons:

- **ELCC is determined directly from the LOLP analysis utilized to calculate the planning reserve margin (PRM) requirement, reflecting a resource's contribution to a specified statistical standard.**

As a derivative of the LOLP modeling used to calculate need, ELCC captures a resource's performance across a wide range of system conditions. This ensures that the estimation of capacity contributions is robust across a wide distribution of potential outcomes, including infrequent extreme events (e.g., higher load and lower renewable output than expected) that are the primary drivers of reliability challenges.

- **ELCC provides a technology-agnostic framework for the measurement of resources' reliability contributions, offering an economically efficient signal for new resource investment.**

This approach therefore puts all resources on a level playing field and ensures equitable treatment among them as well as accurate measurement of their contributions to reliability at the margin. A resource with an ELCC of 1 MW has the same contribution toward resource adequacy, regardless of whether that capacity contribution comes from solar PV, wind, energy storage, natural gas, or coal.

- **ELCC directly accounts for complex interactive effects between different resources in the portfolio, including saturation effects that occur when the penetration of a single resource increases and the diversity benefit attendant to complementary resources.**

ELCC naturally accounts for both the saturation effects that occur as one type of resource is added to the system in increasing quantities and the interactive effects between different types of technologies to provide a comprehensive, accurate measurement of the contribution of dispatch-limited resources to the system. These dynamics are crucial to consider in planning a reliable system that relies heavily on renewable and storage resources.

In practice, the same qualities that make ELCC the most robust method for measuring capacity contribution also make it a complex method to apply. The simplest example of an application of ELCC is in the context of a vertically integrated utility that is responsible for meeting its own resource adequacy requirement with a single portfolio of resources. For such a utility, accrediting capacity value to individual resources is not strictly necessary—what matters is whether the utility's total portfolio meets its total needs. In this case, the application of ELCC may reasonably rely directly on the two "measurable" ELCC values: portfolio and marginal. Both are directly useful to the utility:

- To assess whether a given combination of resources is sufficient to meet a utility's resource needs, the **portfolio (or cumulative) ELCC** provides a measure of the combined capacity contribution of all resources in its portfolio.
- To evaluate potential resource additions, the **marginal ELCC** for each resource provides a measure of how much that resource will increase the total ELCC of the utility's portfolio,

offering a means of comparing the relative capacity value of resource alternatives to identify the least-cost resource among a discrete set of options.

Together, these two constructs can allow a utility to simultaneously ensure the reliability of its existing portfolio of resources and make economically efficient decisions in the procurement of new capacity resources to meet incremental need.

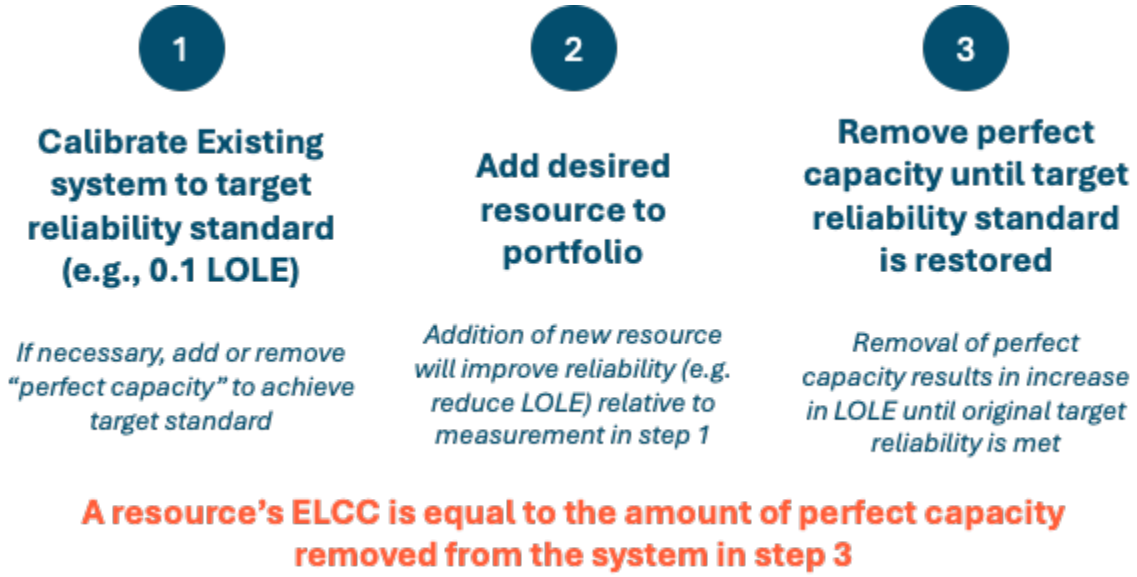
B.5.1 Calculating ELCC

The ELCC is a measure of a resource or a portfolio's contribution to reliability at target reliability. The measurement is typically compared to a hypothetical "perfect" resource. Thus, LOLP models must model the specific system, but also "tune" the system with perfect capacity.

The ELCC calculation is a three-step process:

1. The LOLE for the electric system without target resources is simulated. If the resulting LOLE does not match the specified reliability target, the system is "adjusted" to meet the target reliability standard (e.g. 0.1 days/year) or equivalent standard. This adjustment typically occurs through the iterative addition (or removal) of a perfect capacity resource to achieve the desired reliability standard. This process was more complex for Maritime Electric than for many other systems due to the magnitude of shortfall expected in 2030 without additional resources. Addition of perfect capacity is a reasonable approach to adjust the system if it is a small fraction of the overall generation portfolio, which would not have been the case here. See the following section for further details.
2. The target resource is then added to the system, and reliability metrics are recalculated. This will result in a reduction in the system's expected loss of load, as the amount of available generation has increased.
3. Perfect capacity resources are removed from the system until the reliability metrics return to the specified reliability target. The amount of perfect capacity removed from the system represents the ELCC of the target resource (measured in MW); this metric can also be translated to a percentage value by dividing by the installed capacity of the specified resource. (i.e. average ELCC).

Figure B-3. Calculating ELCC in 3 Steps



B.5.2 Adjusting the LOLE of the Base Model for Maritime Electric

As noted above, before calculating ELCCs of candidate resources the LOLE of the electric system is simulated without additional resources, and the portfolio is adjusted to meet the target reliability for the system. This adjustment is important because it ensures that the types of reliability events candidate resources are evaluated against are of reasonable magnitude and duration, which has a significant impact on the number of loss-of-load events that a candidate resource can eliminate, which in turn directly impacts measured LOLE. Typically, that adjustment is performed by adding 'perfect capacity' to increase the reliability of that system, which is appropriate as long as that addition is a small fraction of the overall system generation capacity and thus does not have a meaningful effect on the types of reliability events experienced on the system. This was not the case for Maritime Electric due to the magnitude of the expected shortfall relative to overall system size (115 MW shortfall with a total reliability need of 421 MW as discussed in Section 5).

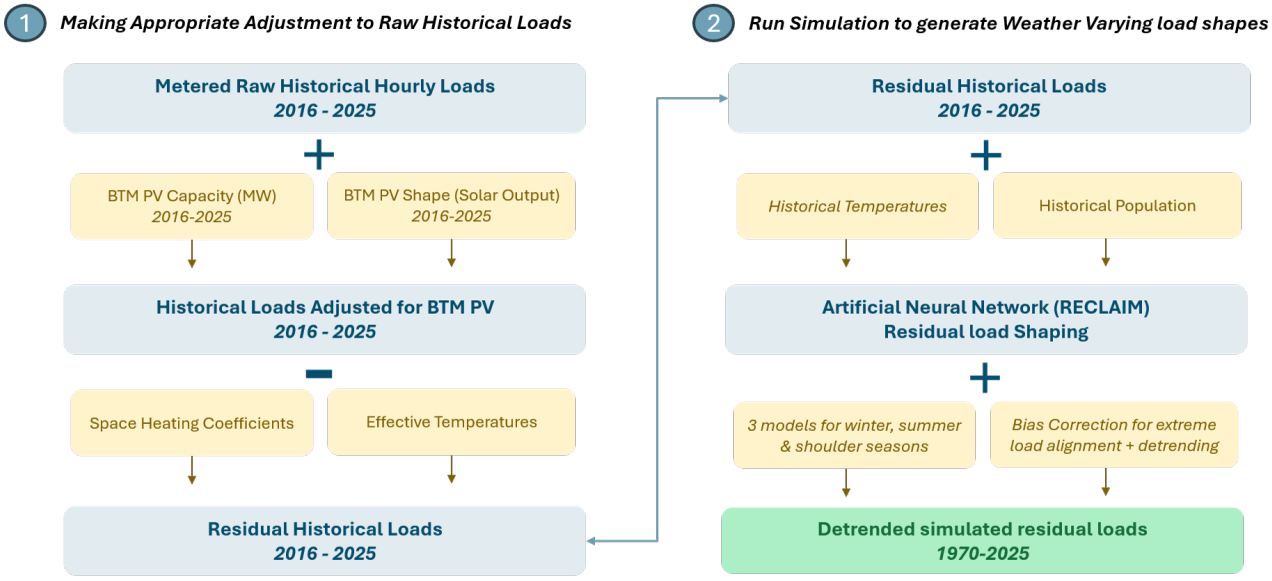
Instead of adjusting the LOLE of the base system by adding only perfect capacity, two 50 MW CTs were added, with the same performance characteristics as Maritime Electric's CT3, including forced outage rate. A small amount of perfect capacity was added additionally to create a base system with 0.1 LOLE on which to measure the ELCC of candidate resources.

Appendix C. Methodology Details

C.1 Hourly Load Simulation

Load shaping is a critical part of any resource adequacy study. Load shapes drive variability, which impacts the Planning Reserve Margin as well as the capacity value of resources. This section summarizes the process used to develop weather-varying load shapes for Maritime Electric's system as used in the Loss of Load Probability Modeling. Load shaping for Maritime Electric was a multi-faceted process, which had two primary parts: (1) Adjusting historical load data & (2) Simulating Weather Varying Load Shapes. Figure C-1 shows a flow chart of all the different steps followed to develop the load shapes.

Figure C-1. Load Shaping process for Maritime Electric



C.1.1 Historical Hourly Loads

Maritime Electric provided E3 with raw historical loads from 2016 to 2025. For resource adequacy as well as load shaping, it is important to have the right magnitude of metered loads that account for behind-the-meter (BTM) PV, as the inclusion of BTM PV can cause loads to change over time with higher penetration of BTM-PV. As a result, the loads were adjusted for BTM PV penetration over time.

C.1.2 Historical Temperature Data

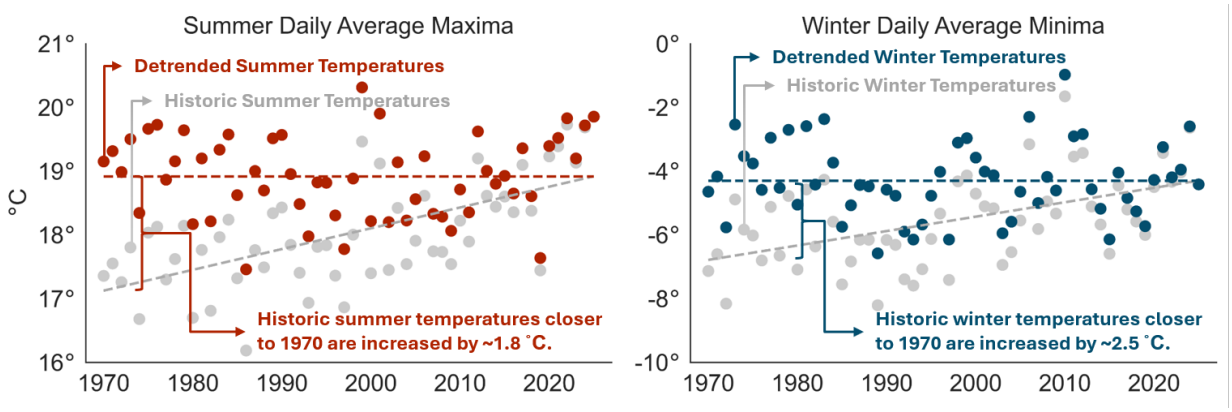
Load Shaping for Resource Adequacy requires a long, extended weather dataset that is internally consistent and spatially complete. Reanalysis temperature datasets, which integrate a wide range of observations through data assimilation, are used to ensure an internally consistent dataset over the required time period.

ERA5 (Land), a global reanalysis dataset developed by the European Centre for Medium-Range Weather Forecasts (ECMWF) with hourly resolution, was used for this analysis. 55 years of historical temperatures were used for this analysis, covering weather years from 1970 to 2025.

C.1.3 Detrending Historical Temperature Data

Incorporating a broad range of plausible weather conditions is essential for capturing the variability of loads. Typically, long-term historical weather records would be used directly to represent the distribution of possible weather conditions. However, as the impacts of climate change become increasingly evident in the observed data, historical temperature may not represent the range of possible temperatures today and into the future. An approach to accounting for the warming impacts apparent in historical observations is to apply a linear adjustment to the extended weather record to remove the long-term trend, also commonly referred to as "detrending". This can be done by first fitting a linear regression to the historical temperature data (e.g., annual maximum daily temperature between 1950 and now) and then "flattening" the series with this estimated trend. The resulting adjusted weather dataset thus becomes more representative of current system climate conditions. The detrending for temperatures in Prince Edward Island is shown in Figure C-2.

Figure C-2. Detrending for Charlottetown from 1970-2025



C.1.4 Space Heating Estimation

Accurately capturing space heating loads requires both appropriate input data (detrended temperatures) and alignment with Maritime Electric planning processes (space heating coefficients). Using Maritime Electric's peak estimation methodology[29], space heating load can be approximated through a linear relationship between temperature and heating demand, based on the provided peak load coefficients.

[29] Refer to Maritime Electric's Space heating estimation work

Figure C-3. Maritime Electric Space Heating Coefficients

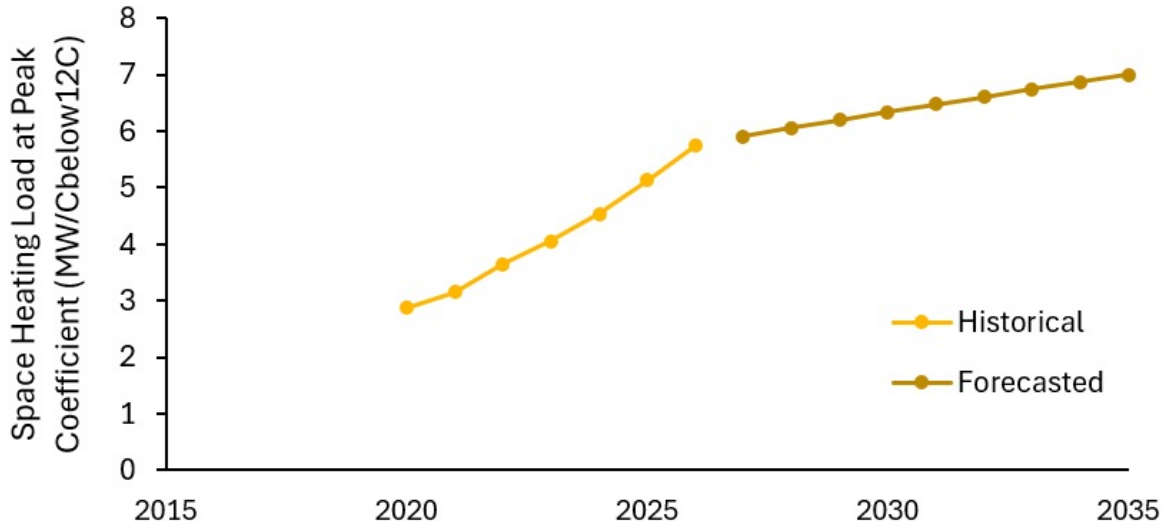


Figure C-3 shows historical and forecasted space heating coefficients for Maritime Electric's system, using these coefficients and the effective temperatures at peak.

Effective temperatures are further calculated using ERA5 Land Simulated data for all 55 weather years. These, multiplied by the space heating coefficient for the selected year, provide an estimate for space heating load for the simulated model year.

Using the same methodology, space heating loads can be estimated for actual observed historical load. Taking out space heating loads from actual historical loads which are adjusted for BTM PV, gives us an estimation of "residual" or baseline loads, which are then simulated using Artificial Neural Network (ANN), discussed in subsequent sections.

C.1.5 Load Shaping with Artificial Neural Network

RECLAIM is an Artificial Neural Network ("ANN") Model that uses a two-layer feedforward neural network, built with the Keras deep learning package[30], to characterize how hourly electricity demand responds to weather and calendar-driven patterns. During the training process, the network is exposed to a sample of historical loads along with the corresponding input features. Through an iterative optimization process, it gradually adjusts its internal weights for each input feature so that its predictions align as closely as possible with the observed load. This two-layer architecture provides enough learning capacity to capture the important non-linear relationships, such as the way demand increases sharply during periods of extreme heat or cold, and the way that daily patterns differ across seasons and day types, while still maintaining transparency and computational efficiency.

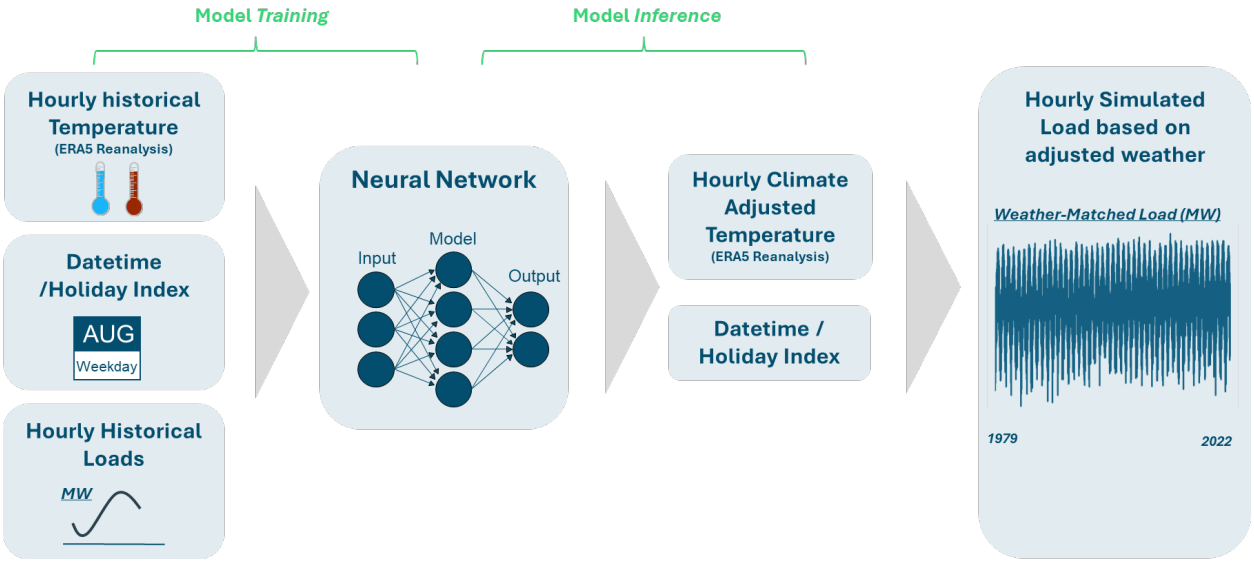
[30] A Python API for building and training deep learning models: https://keras.io/

To make sure the ANN learns patterns that could generalize well beyond the training input, RECLAIM also incorporates a cross-validation technique. The selected historical load sample is first partitioned into training and validation subsets. The neural network is trained only on the training portion and then repeatedly evaluated on the validation subsets that were intentionally separated from the training set. This approach reduces the risk of overfitting, where the model makes predictions by memorizing specific historical patterns instead of learning the true weather–load relationship. It also helps identify hyperparameters that produce stable and high-performing results. Through this validation cycle, RECLAIM ensures that the trained ANN is reliable when applied to the much longer weather record, which includes new weather patterns that have not been seen in sample load inputs or in the training step.

Once training and validation steps are complete, the neural network is applied to infer load across the extended weather dataset, using the same set of input variables calculated from that record. Because the neural network has learned how load responds to weather conditions rather than memorizing any specific historical year, it can estimate hourly demand for every new hour in the extended dataset. This produces a continuous sequence of weather-normalized synthetic loads that reflect present-day load behavior across a wide spectrum of plausible weather conditions, including rare events and sustained extreme weather patterns.

By leveraging modern neural network tools and the robust validation practices, RECLAIM offers the flexibility needed to accurately represent complex, nonlinear load–weather dynamics and produces synthetic load shapes that are grounded in the observed behavior of the present system for use in power system analysis.

Figure C-4. Artificial Neural Network Model Training and Inference Process



C.1.6 Process updates specific to Maritime Electric for Neural Network

The historical year 2020 was fully omitted from the neural network. 2020 was an outlier year, owing to the pandemic. Inclusion of 2020 would have introduced an unnecessary layer of noise in the training and inference of the neural network model.

Maritime Electric's service territory experiences distinct seasons characterized by fluctuations in temperatures between summer, winter and shoulder seasons. To retain the characteristics of each of the seasons, 3 individual neural network models, each for winter, summer and shoulder seasons, were developed. The benchmarking of the model results in the next section is the combined product of 3 separate models combined to create a contiguous time series.

C.1.7 Benchmarking Neural Network Model Results

Once the final synthetic load shapes are produced, the shapes are benchmarked to ensure that the simulated loads are consistent with historical patterns.

Figure C-5. Correlation between Actual Observed and Simulated Peaks

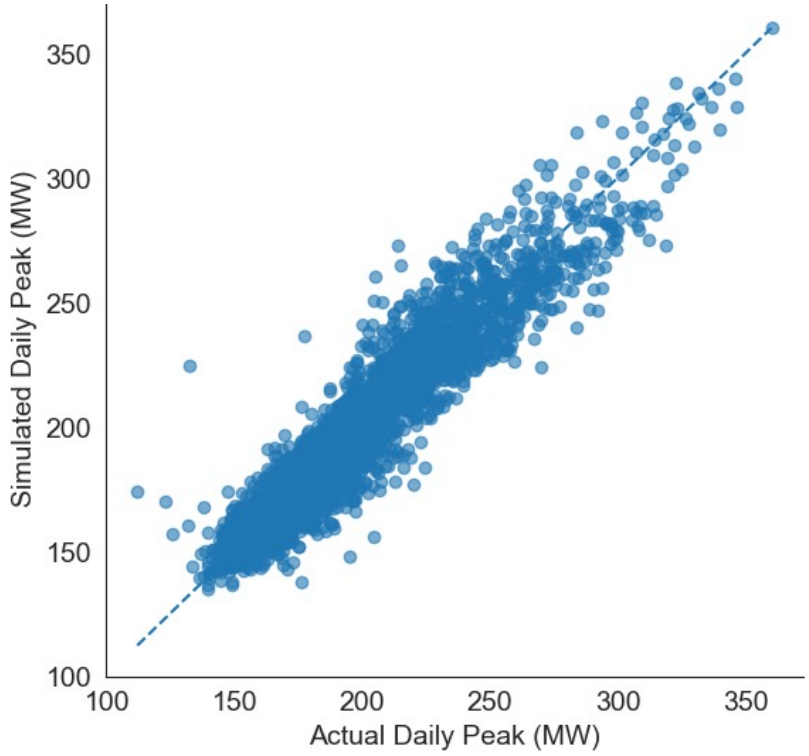


Figure C-5 shows a scatter plot of Observed Daily peaks from 2016 – 2025 vs. the simulated peaks for the same time period. The simulated and observed historical loads show strong correlation, evidenced by an R-squared value of 0.91.

Figure C-6. Comparison of Month-hour loads (Average) between Historical & Simulated Loads excluding Space Heating loads

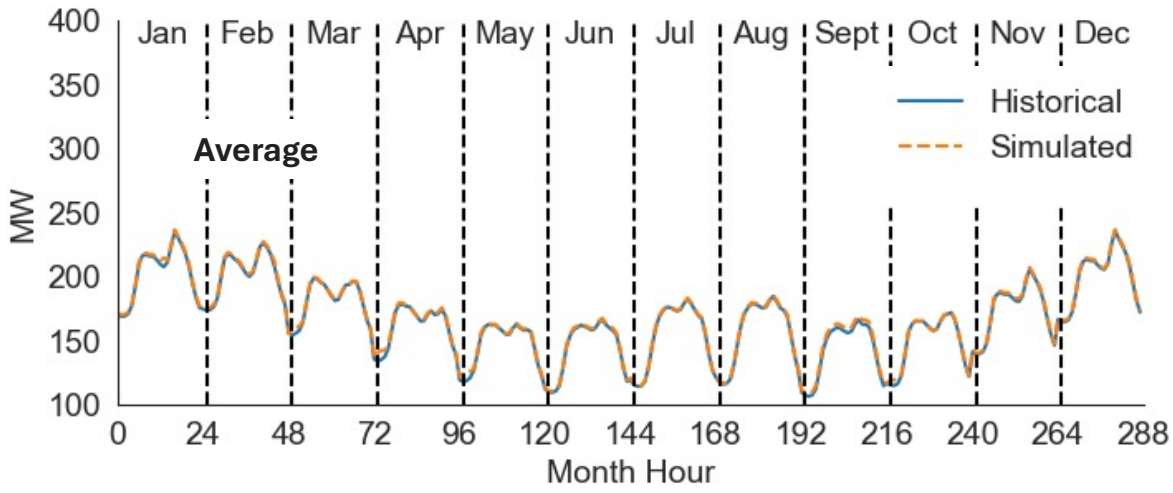


Figure C-6 compares the month-hour average loads across the same historical period of 2016 through 2025, excluding 2020. The historical observed data aligns with the simulated data, as evidenced by overlapping lines.

Finally, loads from RECLAIM are combined with space heating loads to create a load shape that can be compared to the actual historical load.

C.1.8 Final Scaling of Load Shapes

Benchmarked shapes from the neural network and space heating shapes are first each individually scaled to their annual energy demand, which is provided by Maritime Electric for 2026 – 2035. These individual components are then combined and scaled to the Median Peak forecast and the Annual Energy Forecast and used in the LOLP Modeling. The output of the median peak across the weather years matches the median peak provided by Maritime Electric.

C.2 Wind Generation Data

As described in the main text of this report, Maritime Electric purchases energy from eight existing wind resources. Maritime Electric provided E3 with 10 years of metered historical generation data from the existing wind fleet. This data was used to characterize expected future performance of existing and new resources. The historical data is aggregated into 3 groups based on shared meter interconnection locations. In consultation with Maritime Electric staff, E3 pre-processed the metered data to produce generation profiles representing expected future performance. The pre-processing steps for each of the wind groups are detailed in this section of the Appendix. Table C-1 lists the nameplate capacities and average capacity factors for each wind group, the resources assigned to each group, and the average capacity factors of the raw data prior to processing.

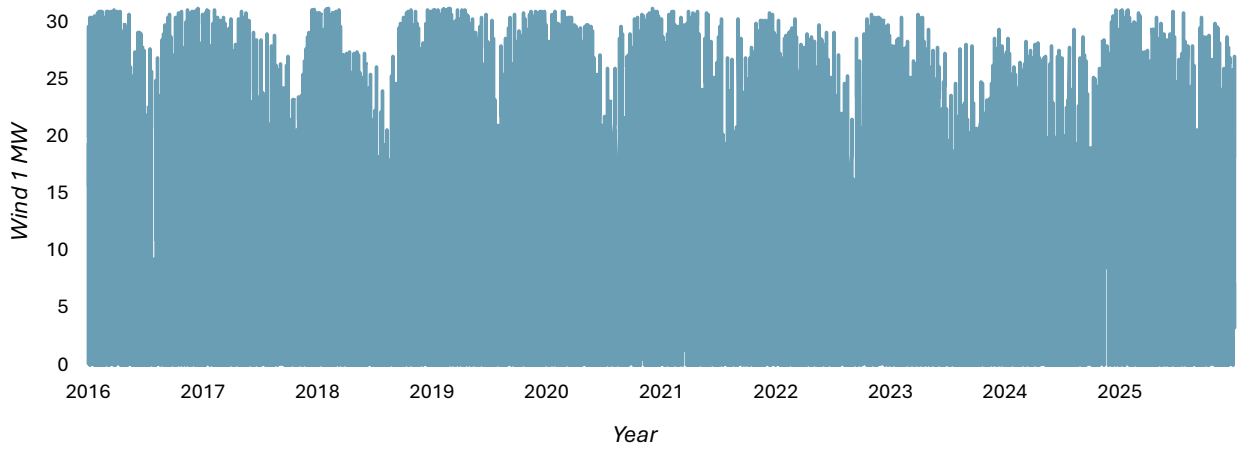
Table C-1. Wind Resources in PEI

Wind Groups	Wind Resources in Group	2030 Nameplate Capacity (MW)	Historical (Raw) Capacity Factor	Adjusted (Modeled) Capacity Factor
Wind 1	North Cape, Norway, Aeolus & WEICAN farms	32.7	38.1%	38.1%
Wind 2	Eastern Kings Phase I	30	34.0%	34.1%
Wind 3	Hermanville / Clearspring	27	30.7%	34.4%
Wind 4	Eastern Kings Phase II	29.4	(NA / new in 2025)	46.6%

C.2.1 Wind 1

Wind 1 metered data was used without adjustment. This profile can be seen in Figure C-7.

Figure C-7. Wind 1 metered data



C.2.2 Wind 2

Wind 2 profile adjustments were implemented to account for the Eastern Kings Phase II installation in late 2025, including a pre-installation drop in generation. The raw profiles can be seen in Figure C-8. Maritime Electric provided data on the hours each turbine operated, which was used to normalize reported generation. In months where a turbine operated fewer than 15 hours, the turbine was treated as offline, the operational nameplate was reduced accordingly, and reported generation was scaled up to represent output absent construction-related impacts. Storm-related outages were retained in the data to reflect real-world reliability conditions. The final post-processed Wind 2 profiles can be observed in Figure C-9.

Figure C-8. Wind 2 pre-processed metered data

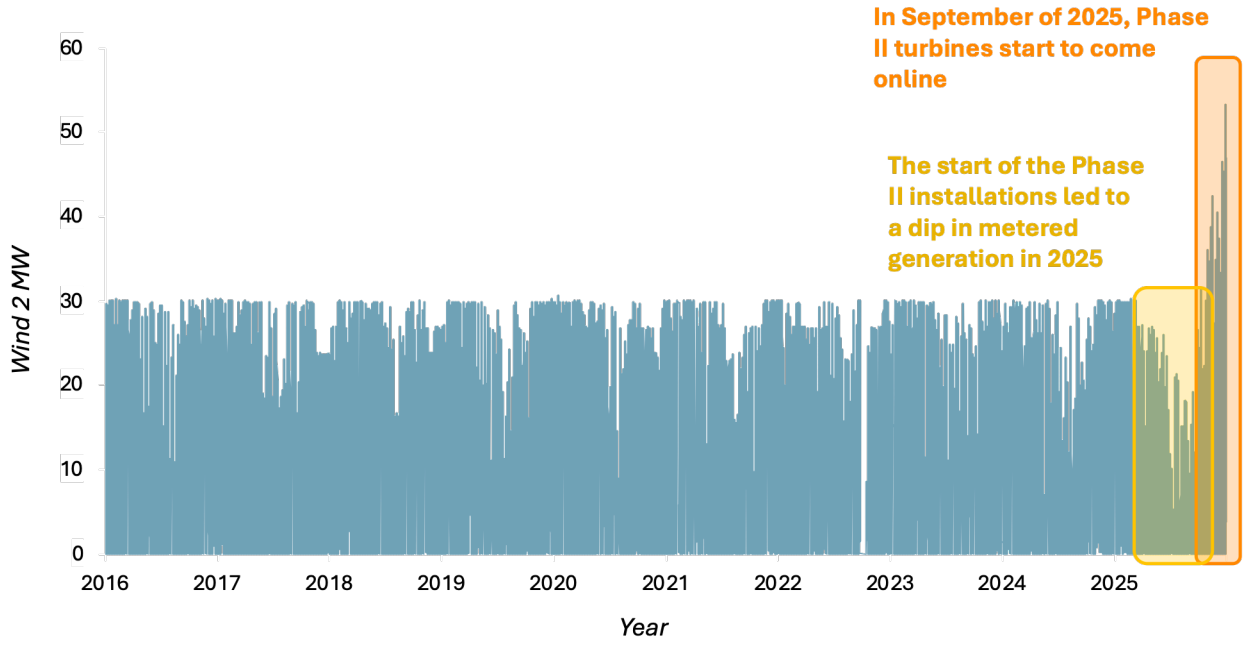
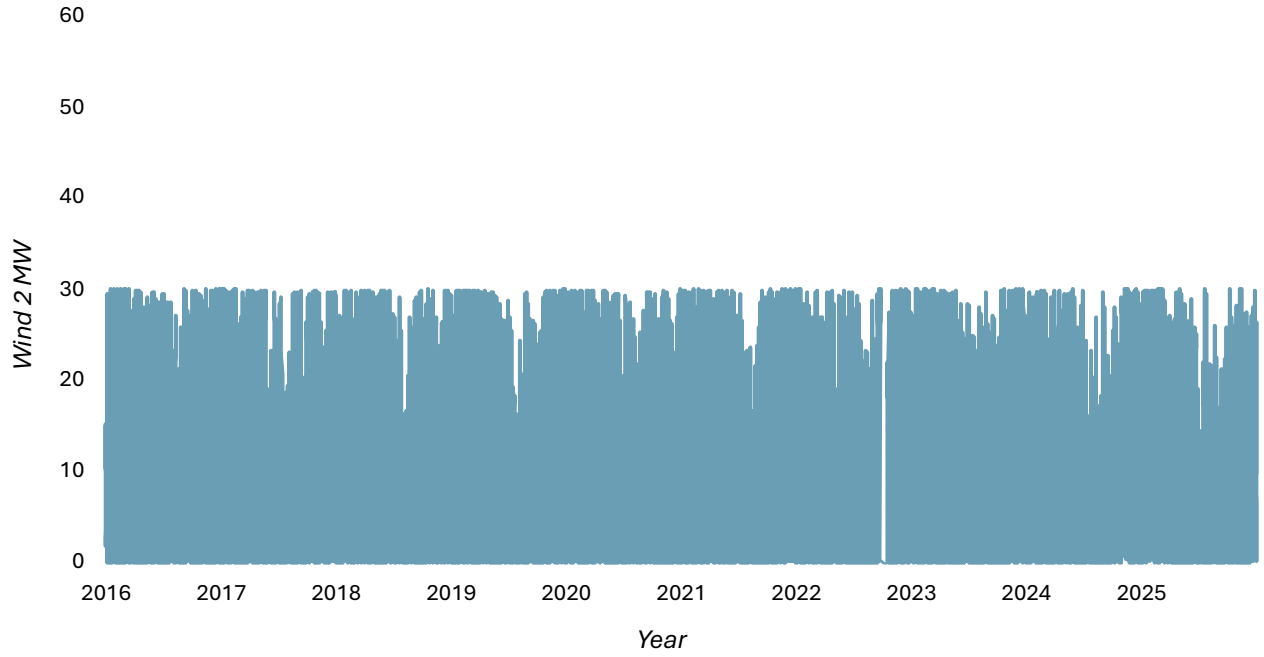


Figure C-9. Wind 2 post-processed metered data



C.2.3 Wind 3

Wind 3 metered data adjustments were implemented to account for extended turbine outages. Beginning in July 2021, multiple turbines came offline and did not return to service, reducing the wind farm's output capacity. Beginning in November 2023, repairs returned most of these turbines to service, increasing output capacity. Modeling future performance requires a generation profile

based on the actual expected operational nameplate capacity of the turbines over time, so adjustments were made to appropriately capture the expected generation of these turbines going forward.

E3 derived a nameplate capacity timeseries reflecting the number of non-operational turbines and used it to scale the metered data to the operational nameplate basis. This timeseries was constructed based on information and guidance provided by Maritime Electric and PEIEC. Adjustments accounted for reduced turbine availability beginning in Fall 2021 and changes in operational nameplate through early 2025. The metered profile data along with the derived nameplate capacity timeseries can be seen in Figure C-10.

As with Wind 2, outages due to weather and maintenance were retained in the profiles, and the randomized forced outage rate input in the model was disabled for this resource. The resulting post-processed data can be observed in Figure C-11.

Eastern Kings Phase I (Wind 2) historical data could not be used directly to represent Eastern Kings Phase II (Wind 4). Although Phase II will occupy the same location as Phase I, the different phases use a newer turbine model with a higher hub height. The developer forecasts a 47% capacity factor for Phase II while Phase I recorded an annual capacity factor of 34.1% over the historical record. E3 developed a function that maps the Phase I timeseries onto the Phase II turbine configuration, accounting for turbine model and hub height, to produce a simulated Phase II generation timeseries scaled to the developer's forecast capacity factor.

Figure C-10. Wind 3 pre-processed metered data and derived nameplate capacity timeseries

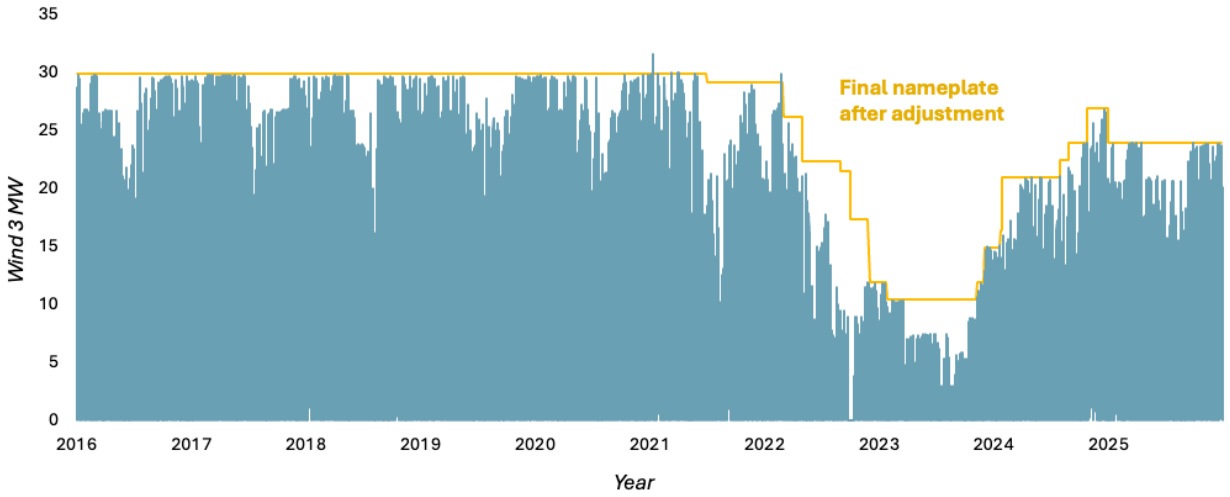
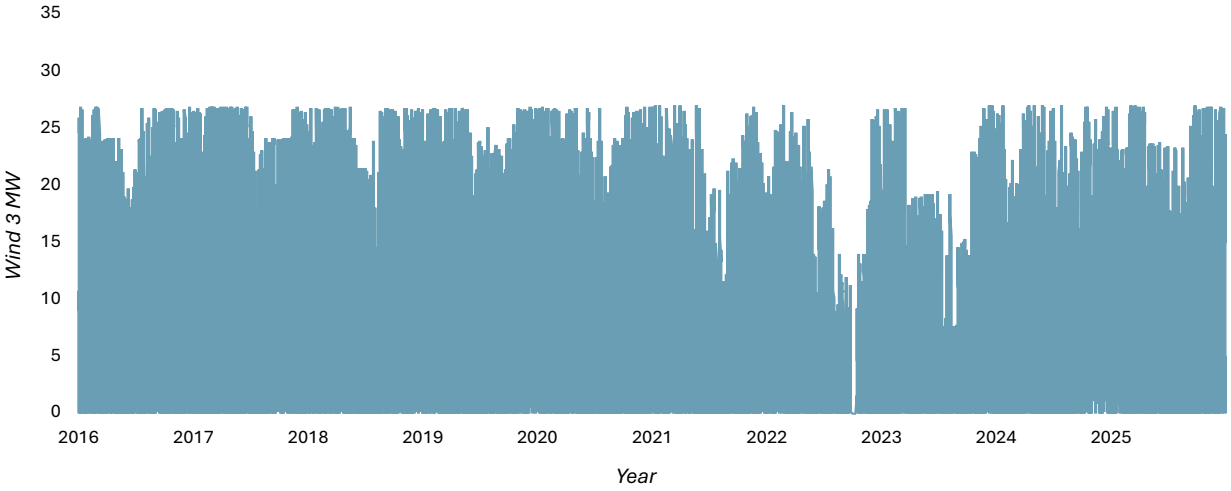


Figure C-11. Wind 3 post-processed data



C.2.4 Wind 4

E3 built the mapping using data from Renewables.Ninja, a model that estimates wind generation by location and accounts for wind speed at hub height and turbine power curves[31]. E3 fit a 3-degree polynomial translating between Renewables.Ninja generation estimates at the Eastern Kings location for the Phase I and Phase II turbine and hub height configurations. Applied to the Phase I historical data, this function produced an estimated Phase II timeseries with a 51.7% capacity

[31] Renewables.Ninja portal: https://www.renewables.ninja/

factor. Exponential downscaling was applied to align the timeseries with the developer's 47% forecast.

Figure C-12. Annual Capacity Factor Comparison: Eastern Kings Phase I (Wind 2) and Phase II (Wind 4) Estimates

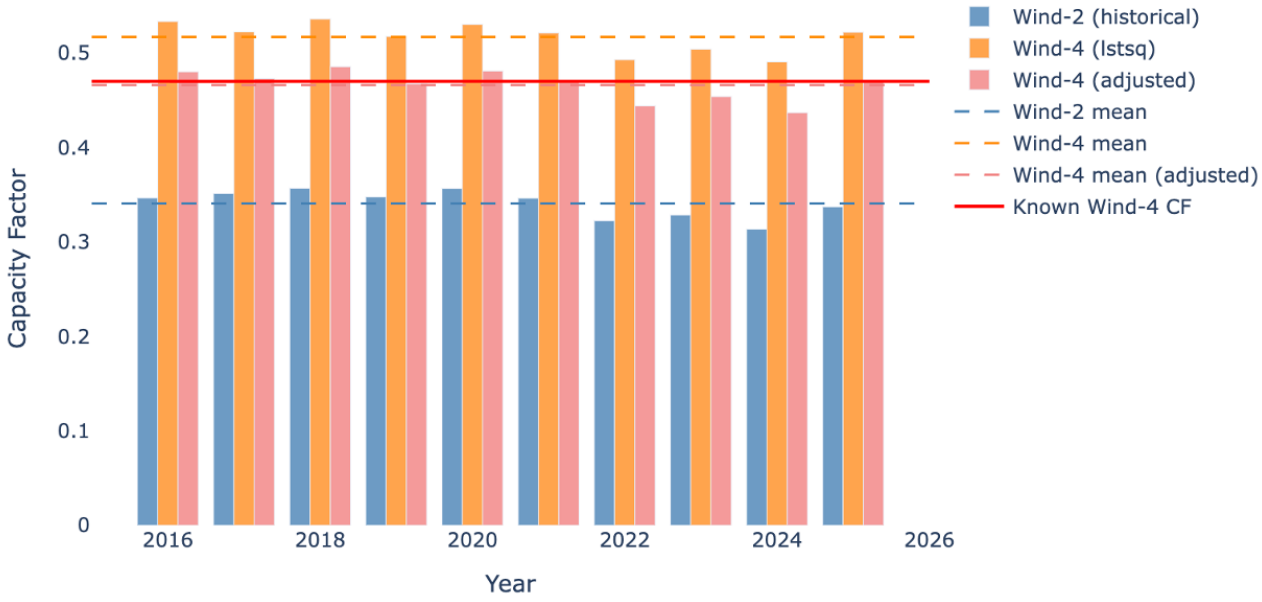


Figure C-13. Fitting a 3-Degree Polynomial to Wind Generation Data

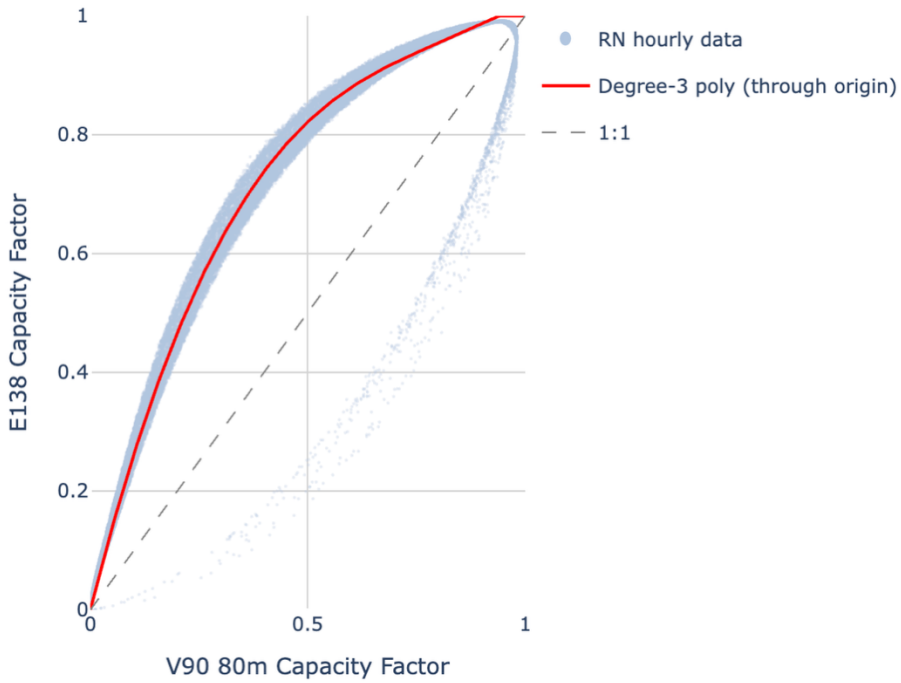
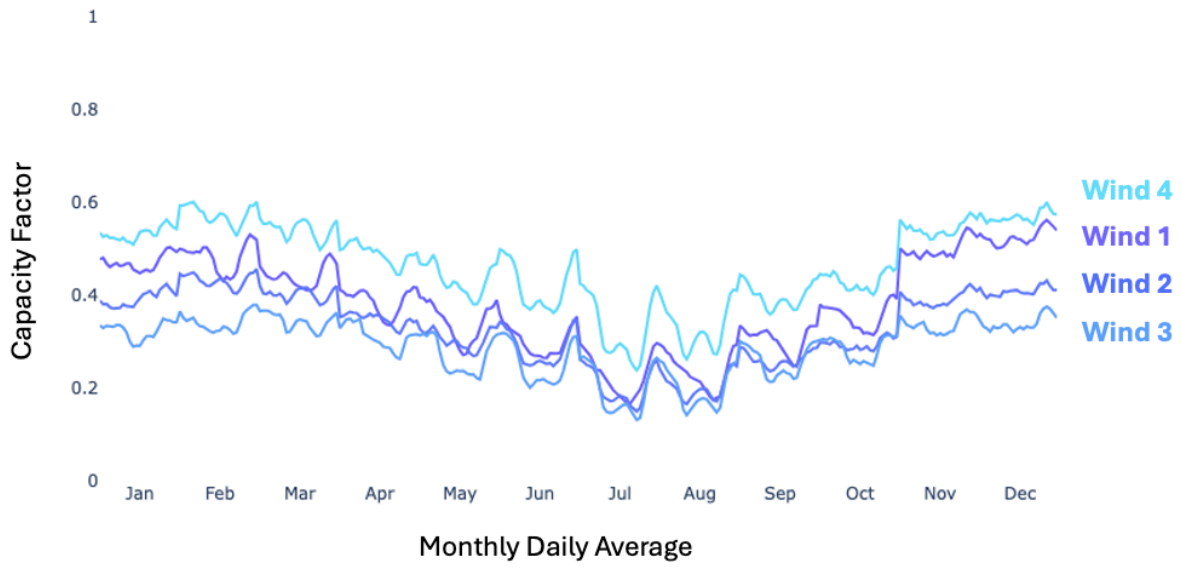


Figure C-14. Wind Daily Month-Hour Average Capacity Factors As Modeled



C.3 Solar Generation Data

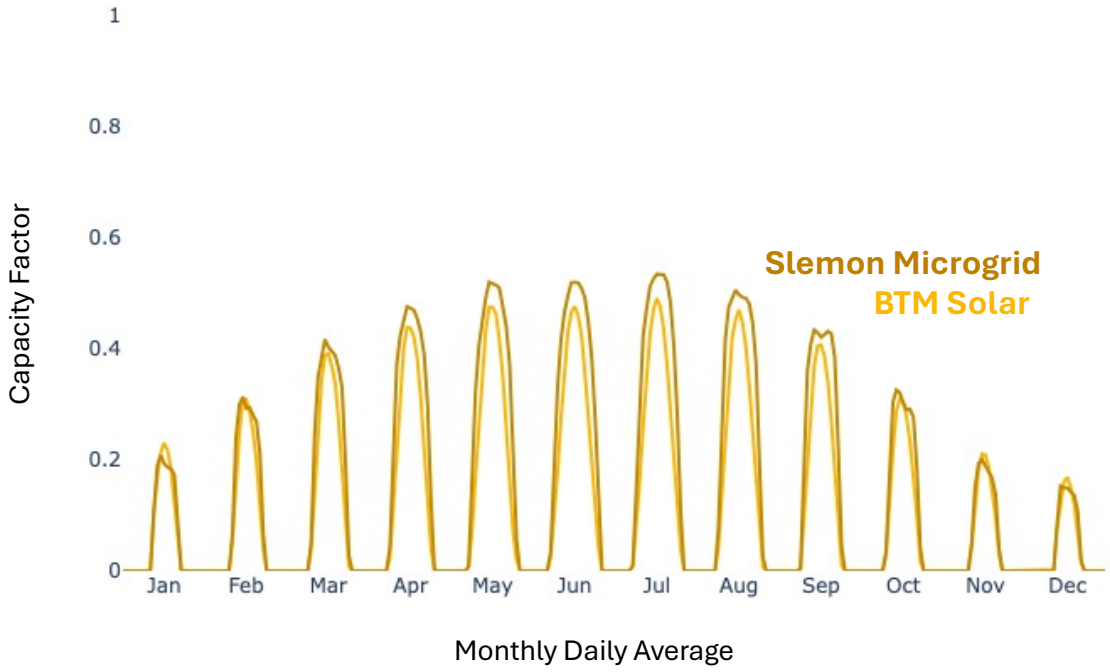
Hourly solar generation profiles for the Maritime Electric RA Study were simulated for 26 historical weather years (1998–2023) using the National Laboratory of the Rockies (NLR) Renewable Energy Potential (reV) model paired with the System Advisor Model (SAM) PVWatts v8 module. Irradiance and meteorological inputs were drawn from the NLR National Solar Radiation Database (NSRDB) GOES-aggregated v4.0.0 dataset (30-minute, satellite-derived), accessed from cloud-hosted HDF5 files via a local HSDS server using the NLR rex library. Each site was assigned the nearest NSRDB grid cell by latitude/longitude.

Five PV profiles were modeled at four Prince Edward Island locations: four behind-the-meter (BTM) systems at Charlottetown (four fixed roof-mount arrays per location at azimuths of 90°, 180°, 270°, and 0°), and the Slemon Park Microgrid. Table C-2 shows the parameters inputted into the SAM PVWatts v8 module. For each site-year, reV executed PVWatts v8 with the site-specific SAM configuration against that year's NSRDB file. The 30-minute resource data were sampled at hourly resolution, producing 8,760 values per year (leap day excluded). Systems were simulated at 1 kW-DC, so outputs are expressed per unit of DC nameplate capacity. AC output is limited by inverter clipping at the reciprocal of the inverter loading ratio (0.806 for BTM systems, 0.769 for the Slemon microgrid). Final BTM profiles combine the four orientation profiles at each location as a weighted average with weights of 15% East, 60% South, 25% West, and 0% North, normalized to sum to one. The Slemon Park Microgrid profile is used directly without orientation weighting.

Table C-2. Input Parameters for Solar Profile Simulation

Parameter	Distributed BTM Solar	Slemon Park Microgrid
Array type	Fixed roof mount	Single-axis tracking
Tilt	35°	Tracking
Azimuth	Blended (East:15% / South:60% / West:25% / North:0%)	180°
Inverter loading ratio (DC/AC)	1.24	1.30

Figure C-15. Solar Profile Daily Month-Hour Average Capacity Factors



IR-30 – Attachment 1

CRAA Tables

TABLE 1 2015 Capacity Resource Adequacy Assessment (MW)										
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Forecast Capacity Requirement	260	263	268	275	282	288	297	307	316	326
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29	29	29
NB Power capacity purchases	77	77	77	50	50	50	50	50	50	50
Wind ELCC	24	24	24	24	24	24	24	24	24	24
Charlottetown Plant	60	60	20	20	-	-	-	-	-	-
CT1	15	15	15	15	15	15	15	15	15	15
CT2	25	25	25	25	25	25	25	25	25	25
CT3	49	49	49	49	49	49	49	49	49	49
CT4	-	-	50	50	50	50	50	50	50	50
Total Capacity Resources	**279**	**279**	**289**	**262**	**242**	**242**	**242**	**242**	**242**	**242**
Capacity Surplus (Deficit)	19	16	20	(13)	(40)	(46)	(55)	(65)	(74)	(84)

TABLE 2 2016 Capacity Resource Adequacy Assessment (MW)										
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Forecast Capacity Requirement	258	262	266	271	277	282	290	299	307	316
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29	29	29
NB Power capacity purchases	100	100	100	100	100	100	100	100	100	100
Wind ELCC	24	24	24	24	24	24	24	24	24	24
Charlottetown Plant	55	55	38	-	-	-	-	-	-	-
CT1	15	15	15	15	15	15	15	15	15	15
CT2	25	25	25	25	25	25	25	25	25	25
CT3	49	49	49	49	49	49	49	49	49	49
CT4	-	-	-	50	50	50	50	50	50	50
Total Capacity Resources	**297**	**297**	**280**	**292**	**292**	**292**	**292**	**292**	**292**	**292**
Capacity Surplus (Deficit)	39	35	14	21	15	10	2	(7)	(15)	(24)

TABLE 3 2017 Capacity Resource Adequacy Assessment (MW)										
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Forecast Capacity Requirement	261	264	267	270	273	276	282	289	295	
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29	29	
NB Power capacity purchases	70	85	80	80	85	90	95	100	105	
Wind ELCC	24	24	24	24	24	24	24	24	24	
Charlottetown Plant	55	38	-	-	-	-	-	-	-	
CT1	15	15	15	15	15	15	15	15	15	
CT2	25	25	25	25	25	25	25	25	25	
CT3	49	49	49	49	49	49	49	49	49	
CT4	-	-	50	50	50	50	50	50	50	
Total Capacity Resources	**267**	**265**	**272**	**272**	**277**	**282**	**287**	**292**	**297**	
Capacity Surplus (Deficit)	6	1	5	2	4	6	4	3	2	

TABLE 4 2018 Capacity Resource Adequacy Assessment (MW)										
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Forecast Capacity Requirement	271	273	275	280	284	291	296	302	307	314
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29	29	29
NB Power capacity purchases	80	85	95	100	95	100	105	110	115	125
Wind ELCC	21	21	24	24	24	24	24	24	24	24
Charlottetown Plant	55	48	38	38	-	-	-	-	-	-
CT1	15	15	15	15	15	15	15	15	15	15
CT2	25	25	25	25	25	25	25	25	25	25
CT3	49	49	49	49	49	49	49	49	49	49
CT4	-	-	-	-	50	50	50	50	50	50
Total Capacity Resources	**274**	**272**	**275**	**280**	**287**	**292**	**297**	**302**	**307**	**317**
Capacity Surplus (Deficit)	4	(0)	0	0	3	2	2	0	0	4

TABLE 5 2019 Capacity Resource Adequacy Assessment (MW)										
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Forecast Capacity Requirement	287	296	303	310	316	321	327	332	338	
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29	29	
NB Power capacity purchases	100	120	125	170	175	130	135	140	150	
Wind ELCC	21	24	24	24	24	24	24	24	24	
Charlottetown Plant	48	38	38	-	-	-	-	-	-	
CT1	15	15	15	15	15	15	15	15	15	
CT2	25	25	25	25	25	25	25	25	25	
CT3	49	49	49	49	49	49	49	49	49	
CT4	-	-	-	-	-	50	50	50	50	
Total Capacity Resources	**287**	**300**	**305**	**312**	**317**	**322**	**327**	**332**	**342**	
Capacity Surplus (Deficit)	0	5	2	3	2	1	1	0	4	

TABLE 6 2020 Capacity Resource Adequacy Assessment (MW)										
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Forecast Capacity Requirement	290	300	309	318	327	336	344	353		
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29		
NB Power capacity purchases	110	120	170	180	135	145	155	165		
Wind ELCC	24	24	24	24	24	24	24	24		
Charlottetown Plant	38	38	-	-	-	-	-	-		
CT1	15	15	15	15	15	15	15	15		
CT2	25	25	25	25	25	25	25	25		
CT3	49	49	49	49	49	49	49	49		
CT4	-	-	-	-	50	50	50	50		
Total Capacity Resources	**290**	**300**	**312**	**322**	**327**	**337**	**347**	**357**		
Capacity Surplus (Deficit)	(0)	0	3	4	0	2	3	5		

TABLE 7 2021 Capacity Resource Adequacy Assessment (MW)										
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Forecast Capacity Requirement	297	306	314	321	329	337	345			
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29			
NB Power capacity purchases	120	165	175	130	140	150	155			
Wind ELCC	24	24	24	24	24	24	24			
Charlottetown Plant	38	-	-	-	-	-	-			
CT1	15	15	15	15	15	15	15			
CT2	25	25	25	25	25	25	25			
CT3	49	49	49	49	49	49	49			
CT4	-	-	-	50	50	50	50			
Total Capacity Resources	**300**	**307**	**317**	**322**	**332**	**342**	**347**			
Capacity Surplus (Deficit)	4	1	3	1	3	6	3			

TABLE 8 2022 Capacity Resource Adequacy Assessment (MW)										
	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Forecast Capacity Requirement	306	311	316	321	328	335	342	348	355	362
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29	29	29
NB Power capacity purchases	165	170	125	130	140	145	150	160	165	170
Wind ELCC	24	24	24	24	24	24	24	24	24	24
CT1	15	15	15	15	15	15	15	15	15	15
CT2	25	25	25	25	25	25	25	25	25	25
CT3	49	49	49	49	49	49	49	49	49	49
CT4	-	-	50	50	50	50	50	50	50	50
Total Capacity Resources	**307**	**312**	**317**	**322**	**332**	**337**	**342**	**352**	**357**	**362**
Capacity Surplus (Deficit)	1	2	1	1	5	3	1	4	2	0

TABLE 9 2023 Capacity Resource Adequacy Assessment (MW)										
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Forecast Capacity Requirement	328	330	333	336	342	348	354	360	366	372
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29	29	29
NB Power capacity purchases	190	190	145	145	150	160	165	170	175	180
Wind ELCC	21	24	24	24	24	24	24	24	24	24
CT1	15	15	15	15	15	15	15	15	15	15
CT2	25	25	25	25	25	25	25	25	25	25
CT3	49	49	49	49	49	49	49	49	49	49
CT4 or RICE	-	-	50	50	50	50	50	50	50	50
Total Capacity Resources	**329**	**332**	**337**	**337**	**342**	**352**	**357**	**362**	**367**	**372**
Capacity Surplus (Deficit)	1	2	4	2	1	4	3	2	1	1

TABLE 10 2024 Capacity Resource Adequacy Assessment (MW)										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Forecast Capacity Requirement	340	386	398	403	409	415	424	434	444	453
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29	29	29
NB Power capacity purchases	201	247	256	211	167	123	132	142	152	161
Wind ELCC	21	21	24	24	24	24	24	24	24	24
CT1	15	15	15	15	15	15	15	15	15	15
CT2	25	25	25	25	25	25	25	25	25	25
CT3	49	49	49	49	49	49	49	49	49	49
CT4	-	-	-	50	50	50	50	50	50	50
RICE Diesels	-	-	-	-	50	100	100	100	100	100
Total Capacity Resources	**340**	**386**	**398**	**403**	**409**	**415**	**424**	**434**	**444**	**453**
Capacity Surplus (Deficit)	(0)	0	0	1	1	0	(0)	0	1	0

TABLE 11 2025 Capacity Resource Adequacy Assessment (MW)										
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Forecast Capacity Requirement	381	401	413	424	435	447	458	470	482	494
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29	29	29
NB Power capacity purchases	185	190	190	190	190	190	190	190	190	190
Wind ELCC	23	26	26	30	30	30	30	30	30	30
Demand Response	-	3	9	14	18	19	19	20	20	21
CT1	15	15	15	15	15	15	-	-	-	-
CT2	25	25	25	25	25	25	25	25	-	-
CT3	49	49	49	49	49	49	49	49	49	49
CT4	-	-	-	-	-	50	50	50	50	50
RICE Diesels	-	-	-	-	-	-	90	100	100	100
BESS	-	-	-	-	10	10	10	10	10	10
Total Capacity Resources	**326**	**337**	**343**	**351**	**365**	**416**	**492**	**502**	**478**	**478**
Capacity Surplus (Deficit)	(56)	(64)	(69)	(72)	(70)	(30)	34	32	(4)	(16)

TABLE 12 2026 Capacity Resource Adequacy Assessment (MW)										
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Forecast Capacity Requirement	402	412	420	428	436	443	450	457	464	471
Capacity Resources										
Point Lepreau	29	29	29	29	29	29	29	29	29	29
NB Power capacity purchases	190	195	200	205	148	110	116	147	154	160
Wind ELCC	26	26	30	30	30	30	30	30	30	30
Demand Response	1	3	10	15	20	21	21	22	23	23
CT1	15	15	15	15	15	-	-	-	-	-
CT2	25	25	25	25	25	25	25	-	-	-
CT3	49	49	49	49	49	49	49	49	49	49
CT4/CT5	-	-	-	-	100	100	100	100	100	100
Other capacity additions	-	-	-	-	20	80	80	80	80	80
Total Capacity Resources	**334**	**342**	**358**	**368**	**435**	**443**	**450**	**457**	**464**	**471**
Capacity Surplus (Deficit)	(68)	(69)	(62)	(60)	0	0	0	0	0	0

IR-43(b) – Attachment 1

NB Power Resource Adequacy Report

Appendix A - Resource Adequacy Report

RESOURCE ADEQUACY REPORT
MARCH 18, 2024

DARREN CLARK, JONATHAN POLLOCK AND ANDREW ROBINSON
NB POWER

Executive Summary

NB Power has experienced load growth due to population growth and electrification in the last few years. This has resulted in a new record system peak on February 4th, 2023 and is driving discussions on expanding NB Power's generation resources. Resource adequacy forecasts are now showing deficiencies in the next 5-years. NB Power has undertaken an exercise to determine the volume of capacity required to reduce this deficiency and has begun discussions on how and where to acquire the new capacity. There are two different considerations when it comes to resource adequacy. First is relating to Loss of Load Expectation (LOLE). The IRP calculates resource adequacy requirements and solves for gaps using this type of probabilistic, risk-based approach. The second is operational resource adequacy. The NBP-SO reports on operational resource adequacy based on a set of deterministic conditions. The operational resource adequacy approach is more conservative than the LOLE assessment. Both assessments are subject to risks that change the capacity required to meet load. These risks include:

1. Changes to the Mactaquac Life Achievement Project (MLAP) outage schedule.
2. Point Lepreau forced outage rate and other forced outages
3. Operational Reserves
4. Load Growth
5. LOLE risk appetite

The assessments show that NB Power needs to begin work immediately to acquire 400 MW of capacity by 2028. Planning at this level will mitigate the risks outlined in the document as well as any potential delays in the installation of this generation.

In addition to this 400 MW of required generation by 2028, NB Power must also begin predevelopment work in 2024/25 for an additional 600 MW that could needed as early as 2030. This will reduce the lead time for future generation needs and allow NB Power to mitigate risks by being adaptable to changing future conditions.

1. Current Situation

NB Power is currently experiencing a period of load growth and is forecasting significant future growth from both population growth and economy-wide electrification. NB Power needs to acquire new generating capacity to maintain system reliability and avoid extended or frequent loss of load events. In addition to the expected load growth NB Power's generation fleet is aging requiring more maintenance outages and is experiencing an increased risk of forced outages. The Mactaquac life achievement and Belledune biomass projects also put uncertainty on availability of those facilities in the near term. NB Power recognizes the need to acquire additional generating capacity, the biggest question is at what volumes. NB Power needs to determine the appropriate amount of new capacity additions by balancing reliability and costs to the rate payer. This involves quantifying the risk NB Power is willing to take in relation to reliability.

2. Planning Reserve Margin

Generation reliability criteria are governed by a metric known as loss of load expectation (LOLE). A loss of load event[1] is defined as a situation where supplies of electricity does not meet demand of electricity (i.e. rolling blackouts). LOLE is a probabilistic calculation of the likelihood of experiencing a loss of load event based on a stochastic analysis of the likelihood available generation capacity not being enough to meet the load demand. NB Power is a member of the Northeast Power Coordinating Council (NPCC) and this council sets reliability practices that interconnected electricity systems follow. The Northeast Power Coordinating Council sets a benchmark of a loss of load expectation of no more than 0.1 days per year.

A recent assessment of the reliability of the Maritimes Area indicates that the minimum generation planning reserve criterion for the Maritimes Area is 20 per cent. This means the capacity of generation resources must exceed the maximum firm peak demand by a minimum of 20 per cent to have sufficient generation available to achieve the 0.1 days per year Loss of Load expectation target. This is the standard to which NB Power has historically done its Integrated Resource Planning and resource adequacy assessments.

The firm load including in-province and firm exports plus reserve margins are projected into the future and compared against the available resources to determine the overall generation adequacy. To the extent there is a shortfall, the IRP will close this gap by adding new resources.

It is important to note that merely meeting this minimum threshold carries a non-zero risk of a loss of load event (i.e. rolling blackouts), of 0.1 days/year. To the extent there is not enough generation to meet the 20 per cent reserve margin, the likelihood of rolling blackouts increases. It is a question of risk tolerance rather than something of certainty, and a day of extreme cold weather or a day with particularly poor generation performance could lead to a loss of load event even if NB Power has met the generation adequacy targets.

[1] It is important to note that February 4th, 2023 did not qualify as a loss-of-load event even though NB Power did have to operate for a short time in violation of operational reserves.

There is a multitude of risk variables to reliability of which, many can be quantified through a LOLE calculation. Some of these factors are within the control of NB Power and some are outside the control of NB Power. Below is a list of these risk factors:

- **Mactaquac Life Achievement Project**– The plan for the project is for the units to be removed from service for a period of 16 months each, where no more than one unit will be out of service during the winters of 2028 through 2034. NB Power is currently planning for one unit's capacity reduction. The risk is that any of the outages could get extended beyond 16 months resulting in NB Power having two units out during the winter period. Losing a second unit from Mactaquac during the winter period would reduce the available capacity by 112 MW.
- **Point Lepreau Forced Outage Rate** –The 2022 Comprehensive Maritimes Area Resource Adequacy Review used a forced outage rate assumption of 5.5%, based on a 5-year historical rolling average. NB Power has recently started budgeting 8% due to recent performance. If the forced outage rate for Point Lepreau is expected to persist at 8%, the reliability impact would be equivalent to losing approximately 60 MW of firm capacity.
- **Non-Lepreau Forced Outage Rates** – NB Power's fleet of generating stations are aging, increasing the preventative maintenance requirements to maintain the current forced outage rates. Failure to keep up with maintenance activities would increase the forced outage rate for the thermal plants which will adversely affect overall system reliability.
- **Load Growth** –Should the load increase at a faster rate than forecast this will put pressure on the loss of load calculation and increase the likelihood of an event. Rapid load growth could create a situation where NB Power's reliability is compromised for a period of years as increasing generation supplies can take years to plan and construct.
- **Commercial and Industrial Electrification** – The process of decarbonization is expected to increase industrial and commercial electricity needs as they switch processes from fossil fuels to clean electricity. To the extent this growth exceeds forecasts, it will result in increased probability of loss of load events.
- **Hydrogen Load** – There is a lot of uncertainty around the timing and potential of Hydrogen production or other large industrial loads in New Brunswick. This timing risk could put significant pressure on NB Power's ability to meet new capacity needs.
- **Belledune Biomass** – NB Power is investigating fuel switching options for Belledune starting in 2030 to align with Federal and Provincial policies to stop using coal as a fuel for electricity generation. There is risk that fuel switching will impact available capacity from the Belledune plant. Until testing is complete there is a risk to the expected capacity of Belledune beginning in 2030.
- **Extreme Weather** – Extreme cold can swing peak demands by 300-400 MW in any given year. The operational characteristics of some variable renewable generation can take units off-line at times that coincide with system peaks. (e.g. wind have operating restrictions when wind gusts get too high, or temperatures get too low.)
- **LOLE Risk** – The LOLE target of 0.1 days per year is not a zero-risk standard. While NB Power has not had a loss of load event in at least 30 years, the political impact of a loss of load event would be significant. Newfoundland had a recent loss of load event which resulted in numerous independent reviews, and significant additional costs to the utility. NB Power risks reputational loss, political interference, and an increase in oversight by building to the minimum standard.

Reliable service to NB Power's customers is of paramount importance, and as their lives have become increasingly dependent on electricity, their risk to rolling blackouts must be minimized.

A final consideration is one of the economics of building too much generation or building the required generation too early. There are many opportunities to sell capacity in the region and any associated costs associated can be mitigated through sales to neighbours, drastically lowering the risk of overbuilding or building too early.

3. Operational Requirements

NERC and NPCC Requirements for Contingency Reserves:

The North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC) set operational requirements for Contingency Reserves and Operating Reserves for NB Power – enforced through the New Brunswick Energy and Utilities Board (NBEUB).

NERC requires that NB Power have Contingency Reserve (Ten Minute Reserve) that is equal to NB Power's Most Severe Single Contingency (MSSC). Typically, the MSSC for NB Power is the Lepreau gross output at 715 MW. If a source loss contingency occurs, NB Power must recover its Area Control Error (ACE) within 15 minutes using Contingency Reserves and then must recover (replenish) it's Contingency Reserves within another 90 minutes (105 minutes in total). There are compliance issues and financial implications with not recovering the ACE for a source loss contingency and not recovering the Contingency Reserve within allotted times.

If Contingency Reserves are depleted simply due to capacity deficiency issues, NERC has an Energy Emergency Alert (EEA) process that would be followed. When declaring an EEA, the entity does not have enough energy to meet firm load, firm export requirements while also having required Contingency Reserves. The EEA process exists to ensure that an entity doesn't overly burden the Eastern Interconnection and neighboring entities.

Not having required Contingency Reserves would mean that for a source loss contingency, or during periods of high load and lack of energy, that the entity could be burdening the interconnection. There are Control Performance Standards (NERC BAL suite of standards) that help ensure an entity doesn't overly burden the Eastern Interconnection. Contingency Reserves are part of these standards and there are several requirements that would be enforceable by the NBEUB (with financial sanctions if non-compliant).

NPCC imposes similar, but slightly more restrictive requirements on NB Power. NPCC requires that NB Power have Ten Minute Reserve that is equal to the First Contingency Loss (same as MSSC described above). NPCC requires that a minimum of 25% of the Ten-Minute Reserve be synchronized. Additionally, NPCC requires that NB Power carry Thirty Minute Reserve equal to half of the Second Contingency Loss (typically Belledune at 466 MW).

NPCC sets requirements for Ten Minute, Ten Minute Synchronized, and Thirty Minute Reserves. If deficient, NPCC has a process and recommendations that should be carried out to recover reserves.

In summary, NERC requires NB Power to carry 715 MW, while NPCC requires 948 MW as Contingency Reserve / Operating Reserve to meet requirements.

Reliability Limits and Impacts to Contingency Reserves

NB Power meets its Contingency Reserve requirements with available capacity from online generation, offline fast start generation, load as reserve, and Reserve Sharing Agreements with neighboring entities.

NB Power has a Reserve Sharing Agreement of 200 MW with ISO-NE but during peak events it is highly probable that the Reserve Sharing would not be available due to constraints with reliability operating limits.

NB Power has a Reserve Sharing Agreement with NSPI for 168 MW of Ten-Minute Reserve and 50 MW of Thirty Minute Reserve but during peak events it is probable that the Reserve Sharing would not be available due to simultaneous issues (similar issues) in NS.

Load as reserve is for 100 MW that can be counted towards NB Power's Ten-Minute Reserve requirement. This is an agreement that is in place with NB Power Distribution. However, load as reserve is not considered when planning the capacity of the system.

This is 100 MW + 200 MW + 168 MW (468 MW) that typically can count towards NB Power's Contingency Reserves (Ten Minute Reserves). However, it is likely to be unavailable during times of significant system stress. Reserve Sharing and Load as Reserve are not counted towards Resource Adequacy Assessments.

Generation Restrictions

Peak events likely occur during extreme cold weather. Wind generation cuts out when temperatures fall below -30 ^{o}C. This impacts the capacity factor which should be considered for wind during peak events and for planning capacity of the system. As part of the Operational Resource Capacity assessment, NBP-SO counts 136 MW from wind generation (NB wind farms + West Cape + Mars Hills).

Operationally, NBP-SO is required to consider forced outage rates on generation. As part of the annual and 18-month resource adequacy assessments, NBP-SO uses a forced outage rate of 200 MW based on historical availability data.

Limitations of imports

During extreme cold temperature driven peak events, import availability can also be severely limited. Imports from Quebec can be restricted due to Quebec's internal transmission and capacity constraints. Imports from Nova Scotia can be restricted due to Nova Scotia internal transmission and capacity constraints. Imports from New England can be restricted due to New Brunswick Power reliability constraints.

In the operational reserve requirement calculations, NBP-SO counts zero availability from each of Quebec, New England and Nova Scotia.

4. Results

Table 1: Resource Adequacy Calculation 2025 to 2030

Load and Resource Balance Calculation							*Operational Requirement Calculation*					
2025	***2026***	***2027***	***2028***	***2029***	***2030***	***Peak Loads***	***2025***	***2026***	***2027***	***2028***	***2029***	***2030***
3223	3224	3225	3234	3242	3250	Net Peak Load Forecast	3223	3224	3225	3234	3242	3250
-110	-110	-110	-110	-110	-110	(Interruptible load forecast)	-110	-110	-110	-110	-110	-110
3113	3114	3115	3124	3132	3140	Total Peak Requirement	3113	3114	3115	3124	3132	3140
649	649	649	650	651	653	20% Reserve margin						
						Largest Contingency Reserve	715	715	715	715	715	715
3762	***3763***	***3764***	***3773***	***3783***	***3793***	***Total In-Province Requirement***	***3828***	***3829***	***3830***	***3839***	***3847***	***3855***
401	410	410	402	402	402	Export load capacity Contracts	371	380	380	372	372	372
4163	***4173***	***4174***	***4175***	***4185***	***4195***	***Total Requirement***	***4199***	***4208***	***4209***	***4211***	***4219***	***4227***
						Resources						
3969	3972	3972	3860	3860	3768	Total Resources Less Wind	3969	3972	3972	3860	3860	3768
162	162	162	162	162	162	Wind	136	136	136	136	136	136
0	0	0	0	0	0	(Unplanned Outages)	-200	-200	-200	-200	-200	-200
4131	***4133***	***4133***	***4022***	***4022***	***3930***	***Total Resources***	***3905***	***3908***	***3908***	***3796***	***3796***	***3704***
-32	***-39***	***-40***	***-153***	***-163***	***-264***	***Net Resource Position***	***-294***	***-301***	***-302***	***-415***	***-423***	***-523***

The planning reserve margin criteria identify a small shortfall today, growing to almost 200 MW in 2028. The operational reserve criteria identify a significant gap of 300 MW today, growing to over 400 MW by 2028. Additional risk factors push these numbers further, as summarized in the following table. While planning for a negative outcome on all of these would be overly conservative, it is extremely likely that the risk of an additional unit out at Mactaquac, driving the minimum requirement in the Planning Reserve Margin criteria up to almost 400 MW.

Table 2: Risk Impacts for Planning Reserve Margin Criteria

	2025	2026	2027	2028	2029	2030
Net Position	-32	-39	-40	-153	-163	-264
Mactaquac Risk	0	0	0	0	-112	-112
Net Position w/ MQ risk	-32	-32	-40	-153	-275	-374
Other Risk Factors						
Lepreau Performance	-60	-60	-60	-60	-60	-60
Wind Availability	-162	-162	-162	-162	-162	-162
No Belledune	0	0	0	0	0	-375
Net Position after all risk factors	-254	-254	-262	-375	-497	-971

Based on the risk analysis, it is recommended that at minimum, we plan for the Mactaquac risk, resulting in a resource need of approximately 200 MW in 2028, and approximately 400 MW in 2030. The upper range of risk factors is approximately 400 MW in 2028 and 1000 MW in 2030.

The operational reserve criteria takes a more conservative lens, so there are some upside risks that should be factored into the analysis, to align the overall risk profiles. A summary of the risk factors on operational reserve are shown below.

Table 3: Risk Impacts for Operational Reserve Margin Criteria

	2025	2026	2027	2028	2029	2030
Net Position	-294	-301	-302	-415	-423	-523
Mactaquac Risk	0	0	0	0	-112	-112
Reserve Sharing Availability of 50%	+234	+234	+234	+234	+234	+234
Net Position w/ MQ risk and some reserve sharing availability	-60	-61	-68	-181	-301	-401
Other Risk Factors						
2nd largest contingency	-233	-233	-233	-233	-233	-162
Wind Availability	-136	-136	-136	-136	-136	-136
No Belledune	0	0	0	0	0	-375
Net Position after all risk factors	-429	-430	-437	-550	-670	1,074

Based on the operational reserve margin risk analysis, it is recommended that at minimum, we plan for the Mactaquac risk and include an upside risk of 50% availability of reserve sharing agreements, resulting in a resource need of approximately 200 MW in 2028, and approximately 400 MW in 2030. The upper range of risk factors inclusive of planning for the second contingency is slightly higher than the planning reserve margin criteria at approximately 600 MW in 2028 and 1100 MW in 2030.

5. **Recommendation**

NB Power needs to be planning now to avoid a significant capacity deficiency in 2030. Both the planning resource adequacy calculation and the operational resource capacity assessment show growing capacity deficiencies in the future. It is recommended that NB Power immediately begin the process of acquiring 400 MW by 2028 and begin in 2024/25 the predevelopment work for an additional 600 MW that could be needed as early as 2030. Adding additional capacity early is extremely low risk, as there are markets where that capacity could be sold today as well as, a significant need in the future for additional simple-cycle turbines identified in the 2023 Integrated Resource Plan. The due diligence and planning for the upper range of units in 2028 is a no-regrets action that will be used in the future. Flexibility in the development for adding additional capacity in the future is also of tremendous value.

Recommendations:

1. Immediately begin process to acquire 400 MW of generation capacity by 2028.
2. Start planning in 2024/25 to add an additional 600 MW as early as 2030.

IR-44 – Attachment 1

Stantec – Review of Long-Term Interconnection Options

Stantec

REVIEW OF LONG-TERM INTERCONNECTION OPTIONS

Technical Report

November 24, 2025

Prepared for:
Maritime Electric

Prepared by:
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Project Number:
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The conclusions in the Report titled Review of Long-Term Interconnection Options are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

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APPENDIX J MARITIME TRANSMISSION SYSTEM NETWORK 1

Executive Summary

Maritime Electric engaged Stantec to conduct a long-term interconnection study in response to rising electricity demand, government electrification mandates, and the aging condition of two of the four submarine cables connecting Prince Edward Island (PEI) to the mainland. The study assessed the performance of the existing intertie with New Brunswick (NB), evaluated future system needs, and identified optimal interconnection options to support PEI's growing load, which is expected to double in the coming years.

The analysis included power flow, reactive power, short-circuit, and dynamic studies using Maritime Electric's PSS®E transmission model and load forecasts. Under moderate-load conditions (≤ 425 MW), the system experienced limited thermal violations. However, at higher loads (~600 MW), significant thermal overloads and voltage violations were observed under both system normal and contingency conditions, indicating the need for substantial system upgrades.

Reactive power assessments showed that up to 400 MVAR of support was required to maintain voltage stability under high-load scenarios (600 MW). Short-circuit and dynamic studies confirmed that the existing system remains within acceptable fault levels and is dynamically stable under current conditions.

Five intertie options were evaluated—four connecting to NB and one to Nova Scotia (NS). Among these, Intertie Option 2, which involves replacing Cables 1 and 2 with new cables using a split routing similar to Cables 3 and 4, was selected for further study due to its balance of technical feasibility, cost, and system performance.

Scenarios with 600 MW and 800 MW imports were analyzed under Intertie Option 2. The system was found capable of reliably supporting 600 MW imports with appropriate upgrades, including new transmission lines, transformer enhancements, and reactive support devices. However, the 800 MW scenarios introduced significant challenges: reactive power requirements exceeded 900 MVAR, and system stability was compromised under certain dispatch conditions.

While the study concludes that a 600 MW import capacity—supported by Intertie Option 2 and targeted system reinforcements—represents the upper limit of reliable imports under the proposed configuration, this does not mean that the Island's total load is limited to 600 MW. As is the case today, where a 300 MW import limit supports loads up to 400 MW through the contribution of on-Island renewable and dispatchable generation, it is expected that with a 600 MW import capability, the PEI system will be able to accommodate loads of up to 800 MW. The additional demand beyond the import limit would be supplied by local renewable and dispatchable generation resources, allowing the system to supply up to 800 MW. Higher import levels may be feasible in the future but would require further analysis and more extensive infrastructure investment.

Acronyms / Abbreviations

AACE	Association for the Advancement of Cost Engineering
EMT	Electromagnetic Transient
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IBR	Inverter Based Resource
IRP	Integrated Resource Plan
NB	New Brunswick
NS	Nova Scotia
PEI	Prince Edward Island
PST	Phase-shifting Transformer
RMS	Root Mean Square

1 Introduction

Maritime Electric operates the transmission system on Prince Edward Island (PEI), which includes the interconnection to the mainland. The system is connected to New Brunswick (NB) via four (4) 138 kV submarine cables - two commissioned in 1977 and two commissioned in 2017. These cables connect to three (3) 138 kV overhead transmission lines in NB: Line L1142 (installed in 1977), line L1143 (originally installed in 1977 and partially replaced in 2017), and line L1244 (installed in 2017).

In response to significant load growth and the aging condition of two of the four submarine cables, Maritime Electric identified the need for a long-term interconnection study.

To support this initiative, Stantec was engaged to conduct a comprehensive assessment of long-term interconnection options.

2 Scope of Work

Stantec's scope of work for this project included the following tasks:

1. Conducting a comprehensive review of the PEI transmission system, including its ability to meet the load forecasts provided by Maritime Electric. This also included consideration of future renewable generation development on the Island.
2. Reviewing the most recent Integrated Resource Plans (IRPs) from neighboring utilities in NB and Nova Scotia (NS) and incorporating relevant findings into the analysis.
3. Developing and Comparing intertie options to determine which configurations best meet the Island's long-term interconnection needs.
4. Assessing the need for additional reactive power support within the PEI system.
5. Analyzing system capacity requirements under the assumption that Cable 1 and Cable 2 are retired at end of life, resulting in an N-1 contingency limit of 180 MW for imports.

3 Methodology

Stantec followed a structured approach to complete the long-term interconnection study, which included the following steps:

1. **System Review**: Assessed the existing PEI transmission system, including load and generation forecasts, and reviewed the current PSS®E model. Initial power flow simulations were conducted to evaluate system performance under current conditions.

2. **Future Planning**: Incorporated Maritime Electric's future transmission plans by preparing PSS®E study cases for the target in-service year of the proposed interconnection. These cases were updated with forecasted load and generation data, as well as planned transmission projects.

3. **Interconnection Alternatives**: Developed and evaluated multiple interconnection alternatives between PEI and the mainland, including:

    a. Replacement of the 1977-era 138 kV submarine cables and associated land-based connections.

    b. High Voltage Direct Current (HVDC) connections from the Eel River converter station in northern New Brunswick to PEI, requiring expansion of the station to enable interconnection.

    c. HVDC connections with new terminals in both NB and PEI.

    d. High Voltage Alternating Current (HVAC) connections (e.g., 230 kV or 345 kV).

    e. Evaluation of optimal connection points, noting that all existing cables currently originate from the same NB substation.

4. **Technical Studies**: Conducted power flow, short-circuit, and dynamic studies for each alternative under normal (N-0) and single contingency (N-1) conditions.

5. **Reactive Power Assessment**: Reviewed Maritime Electric's reactive power standards and assessed the system's reactive power needs for existing and proposed intertie configurations.

6. **Regional Plan Integration**: Reviewed and summarized relevant findings from the IRPs of NB and NS to align the study with regional planning objectives.

7. **Cost Estimation**: Developed high-level, Class 5 budgetary estimates for required transmission upgrades associated with each intertie option, based on the Association for the Advancement of Cost Engineering (AACE) International guidelines for screening-level feasibility assessments.

4 Data and Assumptions

4.1 Data

The following data was utilized in the study:

1. PEI transmission system cases in PSS®E format for current (year 2024) and future years (2027, 2030, and 2033)

2. 2024 ASPEN OneLiner™ data model

3. PEI system load and generation forecast data and PEI transmission project plans
4. Historical cable and system project cost information from Maritime Electric
5. PEI electric system technical standards and reliability criteria including digital copies of:
    a. Maritime Electric's 2022 Capacity Resource Study and the follow-up addendum – Extreme Weather Event Capacity Impact
    b. Maritime Electric's 2020 Integrated Supply Plan document (filed with IRAC in September 2020)
    c. Prince Edward Island Energy Corporation's "2022-23 to 2024-25 Electricity Efficiency and Conservation Plan"
    d. Recommendations made by Synapse Energy Economics Inc. in its review of Maritime Electric's 2020 Integrated System Plan and Distribution Asset Management Plan
6. Digital copies of the Nova Scotia and New Brunswick Integrated Resource Plans, namely:
    a. New Brunswick Power's 2023 Integrated Resource Plan document (filed in July of 2023)
    b. Nova Scotia Power's 2020 Integrated Resource Plan document or an updated 2023 plan
7. Technical information on the existing interconnection and the on-Island transmission system.

4.2 General Assumptions

Stantec made the following general assumptions when performing the work:

1. The system base case may not reflect the most current data. Any outdated information could affect the accuracy and reliability of the study results. Additionally, changes to the PEI System data or connection project forecasts may influence the outcomes of the interconnection analysis.
2. Cost estimates were developed in accordance with the AACE Class 5 classification, which is intended for screening-level or feasibility studies and carries an expected accuracy range of -50% to +100%.

4.3 Load Forecast

The load forecast used in this study reflects Maritime Electric's projections for winter peak demand on PEI through 2033. These forecasts account for anticipated growth driven by electrification initiatives, economic development, and population trends.

Table 1 summarizes the winter peak load forecast ranges used in the study scenarios:

Table 1 Load Forecast	
Study Scenario Year	**Load Forecast Range (MW)**
2024 Winter	350-380[1]
2027 Winter	380-450
2030 Winter	400-600
2033 Winter	400-800

The presented load forecasts were selected in 2024 when this study began. The ranges represent the upper and lower limits of the potential peak loads under low and high electrification scenarios. The range increases for later years due to increase uncertainty. These forecast ranges were applied to develop a variety of study scenarios, including moderate, high-load, and extreme high-load conditions. The upper bound of 800 MW in 2033 reflects an extreme high-growth scenario.

The load forecast data informed the development of power flow, short-circuit, and dynamic study cases, and was used to evaluate the performance of both existing and proposed intertie configurations under future system conditions.

5 Existing Intertie with PEI System

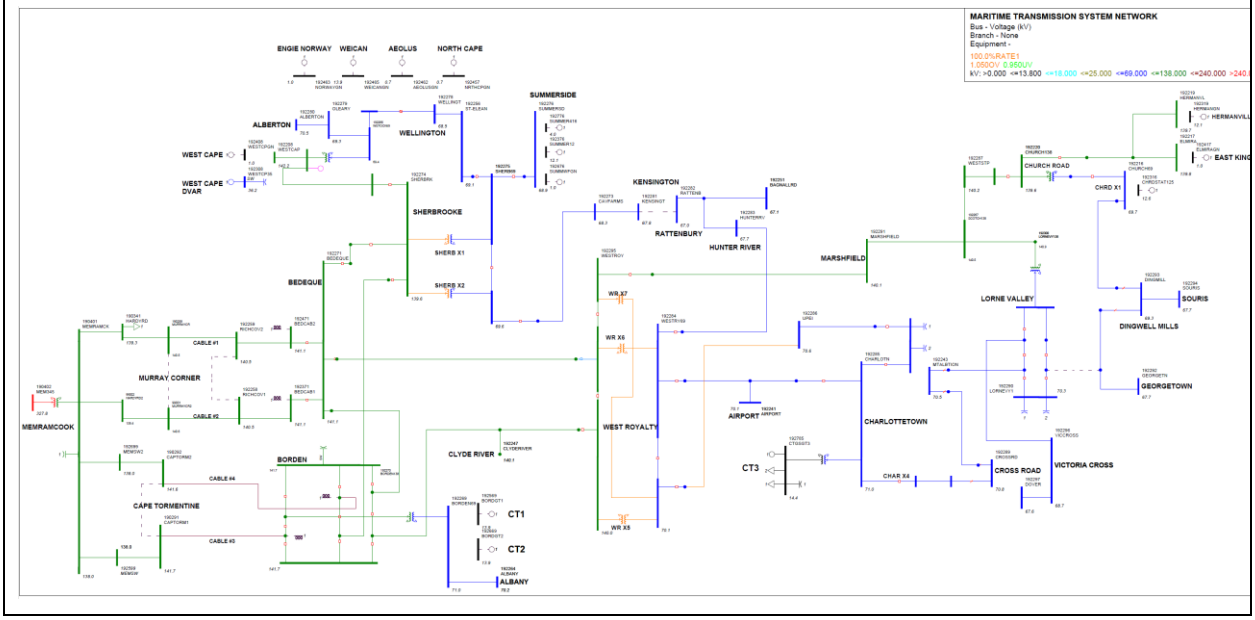
Maritime Electric operates the PEI transmission system that includes the interconnection to the mainland. The system is connected to NB via four (4) 138 kV submarine cables:

1. 138 kV Cable 1 and Cable 2 between Murray Corner, NB and Fernwood, PEI
2. 138 kV Cable 3 and Cable 4 between Cape Tormentine, NB and Borden, PEI

Figure 1 illustrates the PSS®E single line diagram of Maritime transmission system network. A larger version of the single line diagram is presented in Appendix J.

[1] The actual peak load for PEI in 2024 was 342 MW.

Figure 1 Maritime Transmission System Network



5.1 Study Scenarios with Existing Intertie

Stantec performed a power flow study for various study scenarios with the existing intertie between NB and PEI. Table 2 shows the study scenarios used with existing intertie.

Table 2 Study Scenarios for PEI System with Existing Intertie

*Scenario #	Scenario Name	PEI Load (MW)	PEI Generation (MW)	Import (MW)	System Condition
1	2024 90-10 Winter 371 MW	354.6514	0	371	354.65 MW PEI load, no generation dispatch
2	2024 90-10 Winter 300 MW	356.6397	70.7	300	356.6 MW PEI load and dispatchable generations for 300 MW Import
3	2027 90-10 Winter 398 MW	383.8	0	398	383.8 MW PEI load, no generation dispatch
4	2027 90-10 Winter 300 MW	387.1	97.2	300	387.1 MW PEI load, dispatch only dispatchable generation, rest of the from East Kings Wind for 300 MW Import
5	2030 90-10 Winter 422 MW	403.5	0	422	403.5 MW PEI load, no generation dispatch
6	2030 90-10 Winter300 MW	401.9	111	300	401.9 MW PEI load, dispatch only dispatchable generation (existing and new) for 300 MW Import

Table 2 Study Scenarios for PEI System with Existing Intertie					
*Scenario #	Scenario Name	PEI Load (MW)	PEI Generation (MW)	Import (MW)	System Condition
7	2033 90-10 Winter 443 MW	425.2	0	443	425.2 MW PEI load, no generation dispatch
8	2033 90-10 Winter 300 MW	418.9	0	300	418.9 MW PEI load, dispatch only dispatchable generation (existing and new) for 300 MW Import
9	2027 90-10 Winter	385	300		100% wind along with dispatchable generations
10	2030 90-10 Winter	404.5	449	-30.68	100% wind along with dispatchable generations
11	2033 90-10 Winter	422.5	449	-13.22	100% wind along with dispatchable generations
12	2033 90-10 Winter	600.3	245.4	374.49	600 MW PEI load, dispatch only dispatchable generation, rest of the from Tie
13	2033 90-10 Winter	603.1	0	636.51	600 MW PEI load, no generation dispatch
14	2027 90-10 Winter	382.8	203.6	194.95	100% wind and rest from Tie, no dispatchable generations
15	2030 90-10 Winter	403.5	203.6	215.69	100% wind and rest from Tie, no dispatchable generations
16	2033 90-10 Winter	423.7	203.6	236.52	100% wind and rest from Tie, no dispatchable generations
17	2030 90-10 Winter	600.1	245.4	372.63	600 MW PEI load, dispatch only dispatchable generation, rest of the from Tie
18	2030 90-10 Winter	597.3	0		600 MW PEI load, no generation dispatch

Table 2 Study Scenarios for PEI System with Existing Intertie					
*Scenario #	Scenario Name	PEI Load (MW)	PEI Generation (MW)	Import (MW)	System Condition
20	2027 90-10 Winter	175.1	203.6	-17.53	PEI load 175 MW, dispatch 100% wind
21	2030 90-10 Winter	175	203.6	-17.68	PEI load 175 MW, dispatch 100% wind
22	2033 90-10 Winter	175.1	203.6	-17.43	PEI load 175 MW, dispatch 100% wind

**Scenario numbers are not in sequence. The intermittent scenarios are listed in Section 6.3.*

***The difference between PEI Load and the sum of PEI Generation and Import is considered system losses.*

5.2 Power Flow Results

This section summarizes the results of the power flow studies conducted for the scenarios involving the existing intertie between PEI and NB.

The simulations were performed using PSS®E under system normal (N-0) and single contingency (N-1) conditions. The analysis revealed the following key findings:

- Moderate Load Scenarios (≤ 425 MW): In scenarios where PEI system loads were forecasted at or below 425 MW (Scenarios 1 to 11), and dispatchable generation was utilized, only a limited number of thermal overloads were observed. These occurred primarily under N-1 contingency conditions.
- High Load Scenarios (~600 MW): In scenarios with forecasted loads around 600 MW (Scenarios 12 to 18 and 20 to 22), the system experienced a significant number of thermal overloads under both N-0 and N-1 conditions. These overloads indicate that the existing intertie infrastructure is insufficient to reliably support higher load levels without additional system reinforcements.
- Voltage Support Requirements: Across several scenarios, voltage violations were observed. To mitigate these, reactive power support devices were required at multiple locations within the PEI system. These devices were essential to maintain voltage stability and ensure compliance with operational standards.

For detailed power flow results and scenario-specific data, refer to Appendix A.

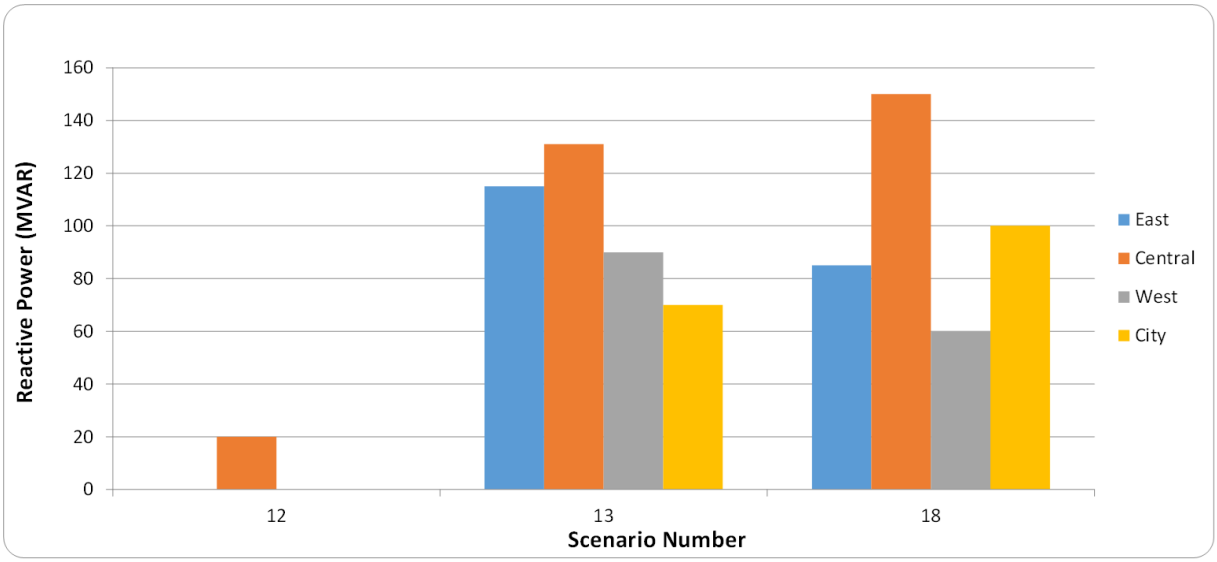
5.3 Reactive Power Assessment

Reactive power assessment study was performed for the scenarios considered in the power flow study. Across several scenarios, voltage violations were observed. To mitigate these, reactive power support

devices were required at multiple locations within the PEI system. These devices were essential to maintain voltage stability and ensure compliance with operational standards.

Figure 2 shows that considerable reactive power support, up to approximately 400 MVARs, were required at various locations within the PEI system to support and stabilize voltages, addressing the voltage range violations.

Figure 2 Reactive Power Support Summary by Study Scenarios and Regions



For detailed device ratings and scenario-specific placements, refer to Appendix B.

5.4 Short-Circuit Study Results

Short-circuit studies were performed using the ASPEN OneLiner™ model provided by Maritime Electric for two selected scenarios: Scenarios 11 and 13. The analysis included calculations for three-phase, line-to-line-ground fault, single line-to-ground, and line-to-line faults at key transmission buses across the system.

The results indicated that fault levels across the 69 kV and 138 kV transmission systems were within acceptable limits, with no significant concerns identified. The only exception was the 138 kV bus at the Memramcook substation in New Brunswick, which is outside the scope of this study.

Detailed results and fault current values are provided in Appendix C.

5.5 Dynamic Study Results

A dynamic stability assessment was conducted using PSS®E for two representative scenarios: Scenarios 11 and 13. These scenarios were selected to evaluate the performance of the PEI system under typical and high-stress operating conditions with the existing intertie to NB.

The analysis focused on system response to a range of contingencies, including faults and generator outages. The results indicated that the PEI system remained stable under all tested conditions, with no evidence of voltage collapse, frequency instability, or oscillatory behavior.

These findings suggest that the existing intertie configuration provides adequate dynamic performance for the current and near-term system conditions.

Detailed dynamic plots and simulation outputs are provided in Appendix D.

6 Proposed Intertie with PEI System

This section outlines the evaluation of long-term interconnection alternatives between PEI and neighboring jurisdictions, with the goal of enhancing system reliability, supporting future load growth, and enabling access to non-carbon-based, economically competitive generation sources. The study considered a range of intertie configurations, including HVAC and HVDC options, as well as varying voltage levels and geographic connection points.

The proposed intertie options were developed in response to several key drivers:

- The aging condition of the 1977-era submarine cables, which are approaching end-of-life.
- Projected increases in electricity demand due to electrification initiatives and economic growth.
- The need for greater import capacity and system flexibility to accommodate renewable energy integration.

Each intertie option was assessed based on technical feasibility, system performance under various load and generation scenarios, and high-level cost estimates. The analysis included power flow, short-circuit, and dynamic studies under system normal (N-0) and single contingency (N-1) conditions.

The following subsections present the details of the proposed intertie configurations, including DC and AC options, study scenarios, technical results, and cost considerations.

6.1 DC Options

HVDC transmission was evaluated as a potential solution for enhancing interconnection capacity between PEI and the mainland. HVDC systems are known for their efficiency in transmitting large volumes of

power over long distances and for their ability to provide system stability and control benefits. However, they also involve higher capital costs, particularly due to the need for converter stations at each terminal.

6.1.1 TECHNICAL AND ECONOMIC CONSIDERATIONS

HVDC systems are typically justified when:

- Transmission distances exceed 80 kilometers (km) for underground/submarine cables or 480 to 640 km for overhead lines.
- Power transfer capacity is sufficiently high to offset the cost of converter stations.
- System separation or asynchronous operation is required.

Cost considerations:

- The cost of converter stations has fallen from $300 million per GW per converter down to a conservatively estimated $200 million per GW per converter.
- Installed cable costs have fallen from over $2 million per GW-km to $0.75 to 1.25 million per GW-km[2].

In the context of PEI, two HVDC configurations were considered:

1. **Option 1**: Construct a new converter station on PEI and connect it to the existing Eel River converter station in northern NB. This would require a minimum transmission distance of 270 km.
2. **Option 2**: Construct two new converter stations - one in PEI and one in NB - and join them. Depending on the location of the stations, the distance could be limited to approximately 25 km.

While technically feasible, both options present significant challenges:

- The Eel River converter station is currently rated at 350 MW and is fully utilized for back-to-back transfers between Hydro-Québec and NB Power. Substantial upgrades would be required to accommodate a new HVDC link to PEI.
- The relatively short distances and moderate power transfer requirements (350 MW – 400 MW) fall below the typical thresholds for HVDC cost-effectiveness.

[2] Buried High-Voltage Direct Current (HVDC) Transmission is Cost Competitive," Nextgen Highways, November 2022. [Online]. Available: https://nextgenhighways.org/wp-content/uploads/2023/01/NGH_Buried-HVDC-Cost-Competitive.pdf.

- PEI and NB are already interconnected via AC infrastructure, so the system isolation benefits of HVDC would not be realized in this case.

6.1.2 BENCHMARKING WITH OTHER PROJECTS

Several global HVDC projects were reviewed for comparison:

- **Neptune Cable**: 500 kV, 660 MW, 100 km submarine/underground cable (New Jersey to Long Island).
- **Cross Sound Cable**: 330 MW, 40 km submarine cable (Connecticut to Long Island).
- **Maritime Link**: 500 MW, 170 km subsea cable (Newfoundland to NS).

These examples demonstrate that short-distance, lower-capacity HVDC projects are possible, but typically serve unique system needs such as asynchronous operation or grid segmentation—conditions not applicable to the PEI-NB system. One of the purposes or benefits of HVDC lines is to provide isolation between the two power system networks which is not possible with AC lines. HVDC technologies can provide extremely rapid stability control, power flow control, and the ability to segment parts of the power system. All of these can enhance the grid's flexibility, reliability, and resilience. However, because PEI and NB power systems are already connected through the AC lines, this isolation purpose would not be achieved by the new HVDC line.

Moreover, electric isolation is not a desired outcome for Prince Edward Island. The PEI system currently relies on the NB system for essential system strength, frequency control, and fault current support. If PEI were electrically isolated from NB, on-Island generation would need to operate continuously—24 hours a day, 365 days a year—to provide these critical services. This would result in a significant and unaffordable increase in operating expenses, as local generation would need to be dispatched at all times regardless of economic or environmental considerations. Therefore, maintaining a strong AC interconnection with NB is essential for both technical reliability and economic sustainability of the PEI power system.

6.1.3 DC OPTION SUMMARY

For both Options 1 and 2, either two new expensive converter stations are required to be built, or one converter station is required to be built new and one existing converter station requires significant updates. This would be very expensive and the transmission line distance and power carrying capacity are considered low as compared to typical HVDC projects. It would also not achieve the purpose of power system isolation which some of the examples of short distance and low power capacity HVDC lines in the world achieve.

Given the high capital costs, limited distance, and lack of system isolation benefits, HVDC is not considered a financially or technically optimal solution for PEI's long-term interconnection needs. The study concludes that AC-based intertie options are more suitable for further evaluation.

6.2 AC Options

AC intertie configurations were also evaluated for enhancing the long-term interconnection between PEI and neighboring jurisdictions. AC options are generally more cost-effective for shorter distances and moderate power transfer levels, and they align with the existing infrastructure and operational practices of the PEI system.

6.2.1 OVERVIEW OF AC INTERTIE OPTIONS

Five AC intertie configurations were assessed in this study. Four of these options connect PEI to NB, while one connects PEI to NS. Table 3 summarizes the configurations.

Table 3 AC Intertie Option Assessed

Intertie Option #	Intertie Option Description
1	Replace Cables 1 and 2 with new cables (Cables 5 and 6), using the same routing and configuration (i.e., one transmission line feeding two cables).
2	Replace Cables 1 and 2 with new cables (Cables 5 and 6), but split the routing similar to Cables 3 and 4 to improve redundancy and reliability (i.e., two lines feeding two cables).
3	Replace the existing 138 kV cables (Cables 1 and 2) with new 230 kV Cables 5 and 6, with new transmission lines from Memramcook to PEI and 345/230 kV transformers at the Memramcook substation.
4	Install 138 kV Cable 5 and 6 Cable between Trenton substation in NS and Dover Road substation on PEI. Upgrade 69 kV line between Dover Road substation and Stratford station to 138 kV.
5	T-tap between 138 kV line Scoudouc substation and near New Castle to 138 kV West Cape Wind Farm.

Key Considerations

- **Option 1** was found to offer limited improvement in intertie capacity and was therefore not selected for further analysis.
- **Option 2** emerged as a strong candidate due to its balance of technical feasibility, cost, and improved redundancy.

- **Option 3** introduces a higher voltage level (230 kV), which could support future load growth and reduce transmission losses, but at a higher capital cost.
- **Option 4** is the only configuration that connects PEI to Nova Scotia, offering potential diversification benefits but also introducing additional complications.
- **Option 5** provides alternative routing and connection points that may be advantageous depending on future system development and regional planning.

Each option was evaluated through detailed power flow, short-circuit, and dynamic studies, as well as high-level cost estimation. The results of these assessments are presented in the following sections.

6.3 Study Scenarios with Proposed Intertie

To evaluate the performance of the proposed intertie configurations, Stantec developed a series of study scenarios representing a range of future system conditions. These scenarios were designed to test the technical feasibility and operational impact of each intertie option under varying load levels, generation dispatch strategies, and import requirements.

Scenario Design

The scenarios focused on winter peak conditions, consistent with Maritime Electric's long-term planning horizon. Each scenario varied by:

- Intertie Option: One of the five proposed AC intertie configurations.
- PEI Load Level: Tested load levels of 600 MW and 800 MW.
- Generation Dispatch: Including cases with full dispatchable generation, no dispatchable generation, and high penetration of inverter-based resources (IBRs).
- Import Levels: Varying as required to serve load under prescribed generation dispatch.

Table 4 lists the scenarios considered.

Table 4 Study Scenarios for PEI System with Proposed Intertie

Scenario #	Scenario Name	PEI Load (MW)	PEI Dispatchable Generation (MW)	Power Import (MW)	Power Flow Scenario Assumptions
12A	2033 90-10 Winter Intertie Option 1	599	245	373	Using PEI's dispatchable generation along with imports from NB to meet the PEI load requirements.

Table 4 Study Scenarios for PEI System with Proposed Intertie					
Scenario #	**Scenario Name**	**PEI Load (MW)**	**PEI Dispatchable Generation (MW)**	**Power Import (MW)**	**Power Flow Scenario Assumptions**
12B	2033 90-10 Winter Intertie Option 2	600	245	374	Using PEI's dispatchable generation along with imports from NB to meet the PEI load requirements.
13A	2033 90-10 Winter Intertie Option 1	604	0	636	Importing power from NB to meet the entire PEI load, with no available dispatchable generation within PEI.
13B	2033 90-10 Winter Intertie Option 2	607	0	629	Importing power from NB to meet the entire PEI load, with no available dispatchable generation within PEI.
13C	2033 90-10 Winter Intertie Option 3	607	0	639	Importing power from NB to meet the entire PEI load, with no available dispatchable generation within PEI.
13D	2033 90-10 Winter Intertie Option 4	617	0	631	Importing power from NB and NS to meet the entire PEI load, with no available dispatchable generation within PEI.
13E	2033 90-10 Winter Intertie Option 5	604	0	637	Importing power from NB to meet the entire PEI load, with no available dispatchable generation within PEI.
18A	2030 90-10 Winter Intertie Option 1	605	0	639	Importing power from NB to meet the entire PEI load, with no available dispatchable generation within PEI.
18B	2030 90-10 Winter Intertie Option 2	601	0	633	Importing power from NB to meet the entire PEI load, with no available dispatchable generation within PEI.
18C	2030 90-10 Winter Intertie Option 3	602	0	633	Importing power from NB to meet the entire PEI load, with no available dispatchable generation within PEI.
18D	2030 90-10 Winter Intertie Option 4	599	0	622	Importing power from NB and NS to meet the entire PEI load, with no available dispatchable generation within PEI.
18E	2030 90-10 Winter Intertie Option 5	600	0	630	Importing power from NB to meet the entire PEI load, with no available dispatchable generation within PEI.
13B_800 MW	2033 90-10 Winter Intertie Option 2	801	0	867	Importing power from NB to meet the entire PEI load, with no available dispatchable generation within PEI.
13D_800 MW	2033 90-10 Winter Intertie Option 4	805	0	850	Importing power from NB and Nova Scotia to meet the entire PEI load, with no available dispatchable generation within PEI.

These scenarios were used to conduct power flow, short-circuit, and dynamic studies under system normal (N-0) and single contingency (N-1) conditions. The results of these studies are presented in the following sections.

6.4 Power Flow Results

This section presents the results of the power flow studies conducted for the proposed intertie scenarios between PEI and neighboring jurisdictions. The simulations were performed under system normal (N-0) and single contingency (N-1) conditions using PSS®E.

Key Findings

- High Load Scenarios with Dispatchable Generation (Scenarios 12A and 12B)

  In these scenarios, PEI system loads were approximately 600 MW, and dispatchable generation was utilized. No thermal overloads were observed under normal (N-0) condition and only a few thermal overloads were observed under N-1 contingency conditions. The system remained largely stable and within acceptable thermal limits.

- High Load Scenarios without Dispatchable Generation (Scenarios 13A & 18A)

  When dispatchable generation was not available, the system experienced a significant number of thermal overloads under both N-0 and N-1 conditions. This indicates that the proposed intertie alone is insufficient to support 600 MW of load without local generation support.

- Extreme High Load Scenarios (800 MW, Scenarios 13B_800 MW and 13D_800 MW)

  These scenarios tested the upper bounds of system import capability. Numerous thermal overloads were observed under both N-0 and N-1 conditions, highlighting the limitations of the proposed intertie options at this load level. These results suggest that importing 800 MW without dispatchable generation would require substantial system reinforcements.

- Voltage Support Requirements

  Across all scenarios, reactive power support was necessary to maintain voltage stability. Devices were required at multiple locations throughout the PEI system to address voltage violations and ensure compliance with operational standards.

For detailed scenario-specific results and thermal loading data, refer to Appendix E.

6.5 Reactive Power Assessment

Reactive power support was evaluated for each of the proposed intertie scenarios to ensure voltage stability and compliance with Maritime Electric's operational standards. The assessment focused on

identifying the locations and sizes of reactive power devices required to maintain acceptable voltage profiles under system normal (N-0) and single contingency (N-1) conditions.

Key Findings

- High Load Scenarios (600 MW)

  In scenarios such as 12A and 12B, where dispatchable generation was available, reactive power requirements were modest. Devices ranging from 20 to 80 MVAR were sufficient to stabilize voltages at key substations, including Borden, West Royalty, and Bedeque.

- Extreme High Load Scenarios (800 MW)

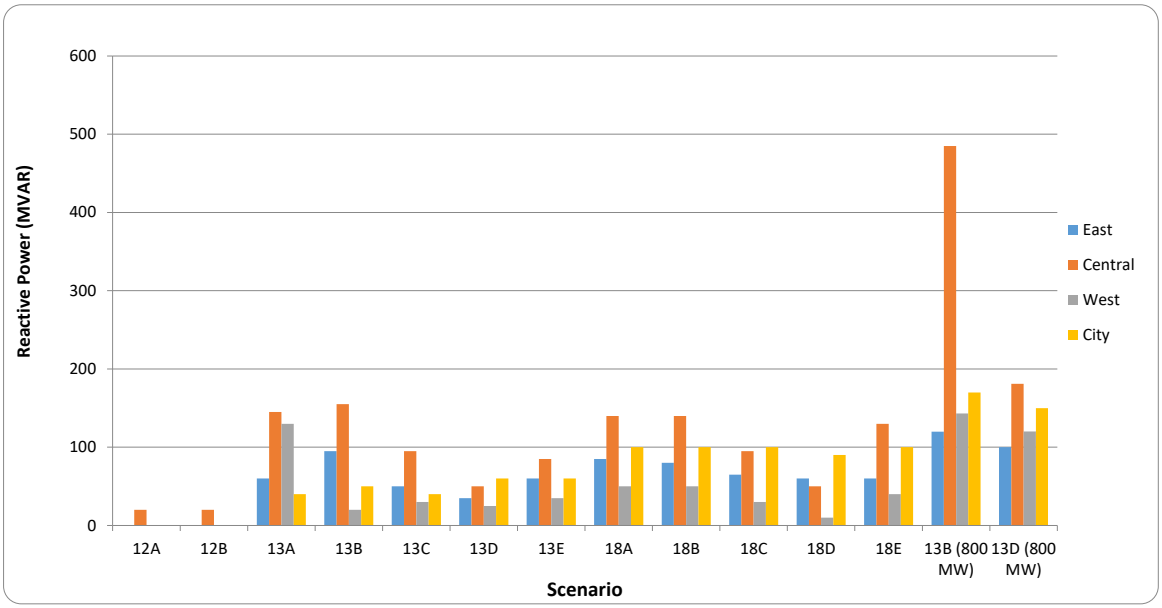
  In scenarios with no dispatchable generation and high import levels (e.g., 13B_800 MW and 13D_800 MW), the reactive power demand increased significantly. In these cases, total reactive support requirements exceeded 900 MVAR, with large Static Var Compensators (SVCs) and capacitor banks needed at multiple substations across the PEI system.

- Geographic Distribution

  Reactive devices were distributed across the island. This widespread deployment highlights the importance of coordinated voltage control strategies, particularly under high-import, low-local-generation conditions.

Figure 3 shows the reactive power support summary by study scenarios and regions.

Figure 3 Reactive Power Support Summary by Study Scenarios and Regions



For detailed device ratings and scenario-specific placements, refer to Appendix F.

6.6 Intertie Options Cost Estimates

Stantec performed order of magnitude cost estimate for various intertie options. Table 5 shows the investment required to meet the transmission upgrade for the proposed intertie options.

Table 5 Order of Magnitude Estimates for Various Intertie Options

Intertie Option #	Intertie Option Description	Transmission Upgrade Cost (CAD in Millions)
1	Replace Cables 1 and 2 with new cables (Cables 5 and 6), using the same routing and configuration (i.e., one transmission line feeding two cables).	Not Estimated
2	Replace Cables 1 and 2 with new cables (Cables 5 and 6), but split the routing similar to Cables 3 and 4 to improve redundancy and reliability (i.e., two lines feeding two cables).	$292.3
3	Replace the existing 138 kV cables (Cables 1 and 2) with new 230 kV Cables 5 and 6, with new transmission lines from Memramcook to PEI.	$448.0
4	Install 138 kV Cable 5 and 6 Cable between Trenton substation in NS and Dover Road substation on PEI. Upgrade 69 kV line between Dover Road substation and Stratford station to 138 kV.	$281.1
5	T-tap between 138 kV line Scoudouc substation and near New Castle to 138 kV West Cape Wind Farm.	$276.7

Option 1 was excluded from further analysis because it does not increase the intertie capacity.

6.6.1 COST ESTIMATE SCOPE AND ASSUMPTIONS

The estimates were prepared in accordance with the AACE Class 5 guidelines, which are appropriate for screening-level or feasibility studies. The expected accuracy range is -50% to +100%.

The general assumptions used for cost estimating for all of the five options include:

- The estimate is based on the AACE Class 5, Expected Accuracy Range -50% to +100%.
- The project in-service-date is assumed to be 2033.
- Each cable is assumed to have a capacity of 180 MW.
- The PEI/NB Interconnection Upgrade Project cost has been used as the baseline estimate, based on Year 2020 dollars. Inflation rates for material and labor costs have been considered.

  - For cable, the annual escalation allowance is assumed to be: (2021: 11%), (2022: 48%), (2023: 23%), (2024:20%), and (2025 to 2033: 3%)
  - For electrical equipment, the annual escalation allowance is assumed to be: (2021: 1%), (2022: 15%), (2023: 14%), (2024: 5%), and (2025 to 2033: 3%).
  - For labor, the annual escalation allowance for 2021 to 2033 is assumed to be 3%.

- Environmental impact costs are not included.
- A contingency allowance is included.
- Salvage costs and/or remediation costs for old cables and infrastructures are not included.

Table 6 presents the high-level scope and intertie option specific assumptions used in the estimate.

Table 6 High-Level Scope and Assumptions

Intertie Option #	High-Level Scope	Assumptions
2	1. New 138 kV AC cables material and installation. 2. A new 50 km, 138 kV transmission line. 3. Upgrade to the Memramcook, NB and Murray Corner, NB substations for the cable tie-line terminations	1. The lengths of the submarine cables are assumed to be 21.7 km. 2. The existing 138 kV transmission line from the Murray Corner, NB substation to the Memramcook, NB substation is assumed to be in-service and a new 50 km, 138 kV transmission line is assumed to be built in parallel. 3. The existing infrastructure and materials of Cable 1 and Cable 2 are not considered for reuse in the estimate.
3	1. New 230 kV AC cables material and installation. 2. Two new 50 km, 230 kV transmission lines 3. Upgrade to the Memramcook, NB and Murray Corner, NB substations for the cable tie-line terminations 4. New 345/230 kV transformation added to the Memramcook, NB substation.	1. The lengths of the submarine cables are assumed to be 21.7 km. 2. Two new 50 km, 230 kV transmission lines are assumed from the Murray Corner, NB substation to the Memramcook, NB substation. 3. The existing infrastructure and materials of Cable 1 and Cable 2 are not considered for reuse in the estimate. 4. A cost factor of 1.6 is assumed for the 230 kV system cost compared to the 138 kV system cost.
4	1. New 138 kV AC cables material and installation. 2. A new 66.5 km 138 kV transmission line from Stratford to Cardigan, then from Cardigan to Dover, and extended to the coastal end. 3. Upgrade to Trenton Generating Station, NS for the cable tie-line termination.	1. The length of the submarine cable is assumed to be 44.2 km. 2. A new 66.5, km 138 kV transmission line is assumed from Stratford to Cardigan, then from Cardigan to Dover, and extended to the coastal end.

Table 6 High-Level Scope and Assumptions		
Intertie Option #	**High-Level Scope**	**Assumptions**
5	1. New 138 kV AC cables material and installation. 2. Construction of new 10 km and 4 km, 138 kV double-circuit transmission lines. 3. Upgrades to the West Cape Wind Farm, PEI for the cable tie-line termination.	1. The lengths of the submarine cables are assumed to be 23.5 km. 2. Two new 138 kV double-circuit transmission lines, one 10 km and other 4 km, are assumed from the transmission line between the Rexton, NB and Bouctouche, NB substations, and West Cape Wind Farm, PEI to the coastal ends. 3. A cost factor of 1.5 is assumed for the 138 kV double-circuit system cost compared to the 138 kV single-circuit system cost.

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6.7 Rationale for Advancing Intertie Option 2

Following a comparative assessment of all five AC intertie configurations, Intertie Option 2 was selected for further study based on its balance of technical feasibility, system performance, and cost-effectiveness. This option proposes replacing the aging Cables 1 and 2 with new cables (Cables 5 and 6), using a split routing approach similar to Cables 3 and 4. This configuration offers several advantages:

- **Improved Redundancy**: The split routing enhances system resilience by reducing the risk of simultaneous outages due to a transmission line trip.
- **Improved Balancing**: As electrical flow is balanced based on transmission line impedances, and not cable properties, providing dedicated transmission lines for each cable allows balanced flow between all four cables.
- **Adequate Capacity**: It supports the projected 600 MW import requirement under high load growth scenarios, aligning with Maritime Electric's 2033 planning horizon even under high electrification scenarios.
- **Cost Efficiency:** With an estimated cost of $292.3 million, Option 2 is more economical than higher-voltage alternatives while still delivering meaningful capacity and reliability improvements.
- **Compatibility:** It integrates well with the existing 138 kV infrastructure, minimizing the need for extensive substation or system-wide upgrades.

Given these benefits, Intertie Option 2 was deemed the most practical and scalable solution for meeting PEI's long-term interconnection needs and was advanced for detailed technical and economic evaluation in Section 7. Additional considerations taken into account in the selection of Intertie Option 2 are listed below:

- The estimated increase in cost for Intertie Option 3 did not justify the increased system benefits for the higher voltage.
- Intertie Option 4 includes a connection to another jurisdiction which could offer additional reliability. However, NS Power is currently faced with removing a large portion of their base-load coal generation from their system and it is currently unknown where it will source the replacement energy and capacity. Also, direct interaction with a second jurisdiction would increase scheduling complexity, necessitate the installation of a phase-shifting transformer (PST)—introducing additional system complexity—and potentially imposing further regulatory compliance requirements. This PST represents a significant capital investment, and its cost was not included in the original estimate.
- Intertie Option 5 offers similar benefits and costs to Option 2. However, since there is no 345 kV transmission source into the Scoudouc substation, this option may not fully meet PEI's needs without a 345 kV transmission expansion in New Brunswick—an upgrade that would depend on NB Power and introduce significant additional costs not included in the current estimate. A review of the NB Power transmission system to determine transfer limitation would outside of the scope of this study.

7 Intertie Options Under Review with PEI System

Intertie Option 2 was selected for further analysis. This configuration was identified as a technically feasible and cost-effective solution that offers improved redundancy and increased import capacity.

7.1 Additional Study Scenarios

To validate the performance of Intertie Option 2 under a range of future system conditions, six additional study scenarios were developed. These scenarios varied by load level, generation dispatch priority, and import strategy. Table 7 summarizes the scenarios.

Table 7 Study Scenarios for PEI System with Intertie Option 2

Additional Scenario #	Scenario Name	PEI Load (MW)	Dispatch Priority 1	Dispatch Priority 2	Dispatch Priority 3*
1	2033 90-10 Winter High Import	600	Import	IBRs	Thermal Resources
2	-	600	Thermal Resources*	Import	IBRs
3	2033 90-10 Winter High IBR	600	IBRs	Import	Thermal Resources
4	2033 90-10 Winter High Import	800	Import	IBRs	Thermal resources
5	-	800	Thermal Resources*	Import	IBRs

Table 7 Study Scenarios for PEI System with Intertie Option 2					
Additional Scenario #	**Scenario Name**	**PEI Load (MW)**	**Dispatch Priority 1**	**Dispatch Priority 2**	**Dispatch Priority 3***
6	2033 90-10 Winter High IBR	800	IBRs	Import	Thermal Resources

**Thermal Resource Priority and Dispatch Priority 3 were not studied.*

Additional Scenarios 1, 3, 4, and 6 were considered for further analysis of the power flow, reactive power assessment, and dynamic studies.

It is noted that Additional Scenarios 2 and 5 prioritized thermal resource dispatch, which inherently strengthens system stability and mitigates many of the thermal and voltage issues observed during periods of high import or high renewable generation. However, because these scenarios represent best-case operating conditions, they do not sufficiently challenge the system or reveal potential vulnerabilities. To better assess system performance under more demanding but realistic future conditions, Maritime Electric recommended focusing on scenarios that prioritize power imports through the interties, supplemented by IBRs. As a result, Scenarios 2 and 5 were excluded from further study.

7.2 Power Flow Results

This section presents the findings from the power flow studies conducted for the additional study scenarios involving Intertie Option 2 and presented in the previous section. The power flow studies were performed under system normal N-0 and single contingency N-1 conditions.

Various thermal overloads were observed across multiple scenarios under N-0 and N-1 conditions. In Additional Scenario 1, where the PEI system was modeled with a 600 MW load and no local generation dispatch, 638 MW of imported power was required. Under these conditions, five thermal overloads were identified in the N-0 case, with an additional ten overloads appearing under N-1 contingencies.

In Additional Scenario 3, the system included a 600 MW load supported by 351 MW of IBR generation. The remaining 276 MW was imported. This scenario resulted in three thermal overloads under N-0 conditions and six additional overloads under N-1. Additional Scenario 4 assumed an 800 MW load with no local generation dispatch, requiring 867 MW of imported power. This scenario produced the highest number of thermal violations, with sixteen overloads under N-0 and twelve more under N-1 conditions.

In Additional Scenario 6, the PEI system operated with an 800 MW load and 471 MW of IBR generation, requiring 372 MW of imports. Seven thermal overloads were observed under N-0, with four additional overloads under N-1.

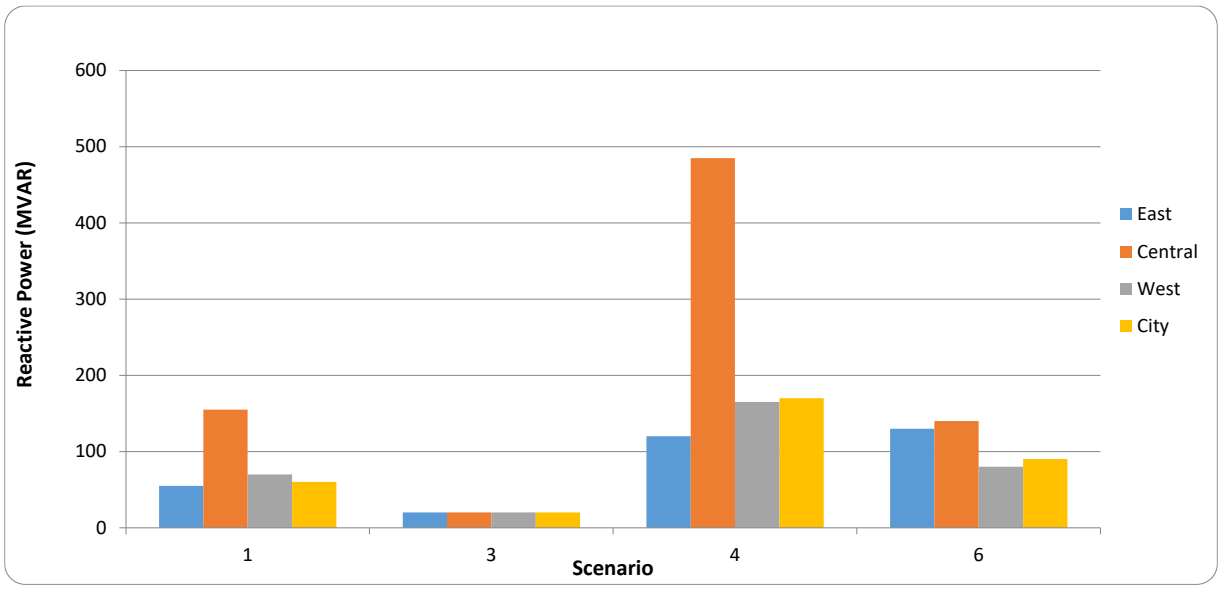
Across all scenarios, voltage range violations were also identified. To mitigate these, several reactive support devices were required at various locations within the PEI system to stabilize voltages and maintain acceptable operating conditions.

For detailed power flow results and scenario-specific data, refer to Appendix G.

7.3 Reactive Power Assessment

Similar to Section 6.5, to ensure voltage stability and compliance with Maritime Electric's operational standards reactive power support was required throughout the system for all additional scenarios assessed. Figure 4 shows the reactive power devices added in the study scenarios with Intertie Option 2.

Figure 4 Reactive Power Support Summary by Study Scenarios and Regions



The reactive power assessment in Section 7.3 revealed that the amount of reactive support required varied significantly depending on the dispatch strategy. Scenarios that prioritized high imports required substantially more reactive power compensation than those where IBRs were given priority.

At the 800 MW load level, the system required over 900 MVAR of reactive support in the high import scenario. This is a remarkable amount for the PEI system and represents almost three times the level of support needed for only a one-third increase in load. This disproportionate scaling suggests that the maximum load that can be reliably served without dispatching significant on-island generation may be close to 600 MW.

Notably, the reactive support requirements in Section 7.3 align with the voltage violation patterns observed in Section 6.5, reinforcing the need for system-wide reinforcement. The combination of capacitor banks and synchronous condensers that will be required to achieve this level of reactive power support is expected to significantly improve voltage profiles and enhance system resilience under both system normal and contingency conditions.

For detailed device ratings and scenario-specific placements, refer to Appendix H.

7.4 Dynamic Study Results

A dynamic assessment was performed for Additional Scenarios 1, 3, 4, and 6 to evaluate the PEI system's stability under various load, import and generation conditions.

Additional Scenarios 1, 3, and 4 demonstrated stable system behavior under all tested contingencies. These scenarios included a mix of dispatchable generation and IBRs, with imports ranging from high to extreme high. The system maintained acceptable voltage and frequency responses, and no signs of voltage collapse or oscillatory instability were observed.

Additional Scenario 6, however, revealed dynamic instability. This scenario involved an 800 MW load with a high proportion of IBRs and limited dispatchable generation. The system exhibited signs of instability following disturbances, indicating that under such conditions, the PEI system may not be dynamically secure without additional control measures or system reinforcements.

These results highlight the importance of dispatch strategy in maintaining dynamic stability. Scenarios with a balanced mix of imports and local generation—particularly dispatchable resources—tend to perform better under dynamic stress. The findings also suggest that while the system can accommodate high imports under certain conditions, there is a threshold beyond which stability may be compromised, especially when relying heavily on IBRs.

For detailed simulation plots and contingency responses, refer to Appendix I.

8 Summary of Analysis

Maritime Electric commissioned this long-term interconnection study in response to accelerating electrification mandates, rapid load growth, and the aging condition of two of the four submarine cables connecting PEI to the mainland. The study evaluated the performance of the existing intertie with NB, assessed future system needs, and identified optimal interconnection configurations to support PEI's evolving energy landscape.

The analysis began with a review of the existing intertie, incorporating load forecasts, generation scenarios, and the current PSS®E transmission model. Power flow studies revealed that under moderate load conditions (≤ 425 MW), the system experienced only limited thermal violations, primarily under N-1 contingencies. However, at higher load levels (~600 MW), the system exhibited widespread thermal overloads under both system normal (N-0) and contingency (N-1) conditions, indicating that the existing infrastructure is insufficient to support future demand without significant upgrades.

Reactive power assessments showed that up to 400 MVAR of support was required to maintain voltage stability under high-load scenarios (~600 MW). These findings were consistent with observed voltage violations and underscored the need for widespread deployment of reactive compensation devices.

Short-circuit and dynamic studies confirmed that the existing system remains within acceptable fault level limits and is dynamically stable under current and near-term conditions.

To address future needs, the study evaluated five intertie options—four connecting to NB and one to NS—including both HVAC and HVDC configurations. HVDC options were deemed technically feasible but economically unjustifiable due to high capital costs, short transmission distances, and lack of system isolation benefits. AC options, particularly Intertie Option 2 (Cables 1 and 2 replaced with similar cables to 3 and 4 and with a similar separate transmission line configuration), emerged as the most practical solution, offering improved redundancy, sufficient import capacity (up to 600 MW), and compatibility with existing infrastructure at a reasonable cost.

The study also explored additional scenarios under Intertie Option 2, including high-import and high-IBR configurations at both 600 MW and 800 MW load levels. These scenarios confirmed that while the system can reliably support 600 MW imports with appropriate upgrades, the 800 MW scenarios introduced significant thermal and voltage challenges. Reactive power requirements exceeded 900 MVAR in some cases, and dynamic instability was observed in scenarios with high IBR penetration and limited dispatchable generation.

Overall, the study concludes that Intertie Option 2, combined with targeted system reinforcements and reactive support, provides a technically sound and economically viable path forward for PEI’s long-term interconnection strategy.

9 Recommendations and Future Direction

Stantec finds that a 600 MW import capacity from NB, can be accommodated by the PEI system with significant upgrades to both the transmission network and intertie infrastructure. Intertie Option 2 was selected for further study, but Intertie Option 5 has comparable costs and an alternate connection point to the NB Power system. If Scoudouc substation is upgraded in the future this option should be considered. The development of additional capacity resources, like the wind west project, in NS could also impact the future viability of Option 4 (i.e., interconnect with NS). These configurations could enhance redundancy and enable the system to reliably serve 600 MW in the future.

The initial intertie expansion assessment considered a range of options, including variations in the number of interties and different AC voltage levels. Among these, a 230 kV intertie option was evaluated. While not selected for immediate implementation, this higher-voltage alternative offers long-term benefits. As Maritime Electric loads near 700 MW or more, a 230 kV intertie could reduce transmission losses and facilitate future upgrades to 230 kV circuits within the PEI system. This option should be revisited as part of future planning, when minimum loads are higher to ensure scalability and efficiency.

It is important to note that the dynamic analysis conducted in this study was not exhaustive. The simulations focused on steady-state dynamic responses under various loading scenarios. Some scenarios—particularly those with high IBR penetration and limited dispatchable generation—exhibited stability concerns. These limitations stem in part from the use of root-mean-square (RMS) simulation tools such as PSS®E, which may not fully capture fast-acting dynamic phenomena.

To address this, future studies should incorporate electromagnetic transient (EMT) simulations using tools like PSCAD. EMT analysis will provide a more accurate representation of system behavior under fault conditions and help assess the impact of IBRs on protection schemes and overall system stability.

APPENDICES

Appendix A Power Flow Results for PEI Existing Intertie Scenarios

A.1 Power Flow Results

The tables below present the power flow results for PEI current intertie scenarios.

A.1.1 SCENARIO 1

Table 8 shows the thermal criteria violations identified in Scenario 1.

Table 8 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 1

Contingency (System Element Lost)	Violation Location Details	Thermal Ratings (MVA)		Results	
		Normal Rating	Emergency Rating	Power Flow (MVA)	% Loading
System Normal	69 kV Line (Sherbrook - Summerside)	32	32	38.14	119.18
System Normal	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	62.92	125.84
System Normal	T1 (Sherbrooke 138/69 kV Transformer T1)	50	50	62.92	125.84
CABLE 1 (Murray Corner - Richcove/Fernwood)	69 kV Line (Sherbrook - Summerside)	32	32	40.41	126.27
CABLE 1 (Murray Corner - Richcove/Fernwood)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	61.53	123.06
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	131.71	118.65
CABLE 1 (Murray Corner - Richcove/Fernwood)	T1 (Sherbrooke 138/69 kV Transformer T1)	50	50	61.53	123.06
CABLE 2 (Murray Corner - Richcove/Fernwood)	69 kV Line (Sherbrook - Summerside)	32	32	40.41	126.27
CABLE 2 (Murray Corner - Richcove/Fernwood)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	61.53	123.06

Table 8 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 1					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	131.71	118.65
CABLE 2 (Murray Corner - Richcove/Fernwood)	T1 (Sherbrooke 138/69 kV Transformer T1)	50	50	61.53	123.06
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	97.65	130.2
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	50	50	65.43	130.86
T3 (Westroy 138/69 kV Transformer T3)	69 kV Line (Sherbrook - Summerside)	32	32	38.32	119.74
T3 (Westroy 138/69 kV Transformer T3)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	62.73	125.46
T3 (Westroy 138/69 kV Transformer T3)	T1 (Sherbrooke 138/69 kV Transformer T1)	50	50	62.73	125.46
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	97.65	130.2
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.43	130.86
T2 (Westroy 138/69 kV Transformer T2)	69 kV Line (Sherbrook - Summerside)	32	32	38.32	119.74
T2 (Westroy 138/69 kV Transformer T2)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	62.73	125.46
T2 (Westroy 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	50	50	62.73	125.46
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	79.57	159.13
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	50	50	79.57	159.13
T1 (Westroy 138/69 kV Transformer T1)	69 kV Line (Sherbrook - Summerside)	32	32	38.55	120.48
T1 (Westroy 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	62.51	125.01

Table 8 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 1					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Westroy 138/69 kV Transformer T1)	T1 (Sherbrooke 138/69 kV Transformer T1)	50	50	62.51	125.01
T1 (Sherbrooke 138/69 kV Transformer T1)	69 kV Line (Sherbrook - Summerside)	32	32	40.79	127.45
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	131.5	263
T2 (Sherbrooke 138/69 kV Transformer T2)	69 kV Line (Sherbrook - Summerside)	32	32	40.79	127.45
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	50	50	131.5	263
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	81.98	102.48
T13 (Charlottetown North - UPEI)	69 kV Line (Sherbrook - Summerside)	32	32	38.23	119.45
T13 (Charlottetown North - UPEI)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	62.82	125.65
T13 (Charlottetown North - UPEI)	T1 (Sherbrooke 138/69 kV Transformer T1)	50	50	62.82	125.65
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	83.77	104.71
T15 (Charlottetown North - T15 Tap)	69 kV Line (Sherbrook - Summerside)	32	32	38.16	119.25
T15 (Charlottetown North - T15 Tap)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	62.89	125.79
T15 (Charlottetown North - T15 Tap)	T1 (Sherbrooke 138/69 kV Transformer T1)	50	50	62.89	125.79
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	83.28	104.1
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	94.18	117.72

Table 8 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 1					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (T15 Tap - West Royalty)	69 kV Line (Sherbrook - Summerside)	32	32	38.21	119.41
T15 (T15 Tap - West Royalty)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	62.84	125.68
T15 (T15 Tap - West Royalty)	T1 (Sherbrooke 138/69 kV Transformer T1)	50	50	62.84	125.68

A.1.2 SCENARIO 2

Table 9 shows the thermal criteria violations identified in Scenario 2.

Table 9 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 2					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.77	126.36
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	50	50	63.5	127
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.77	126.36
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.5	127
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	77.48	154.97
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	50	50	77.48	154.97

Table 9 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 2					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	98.66	197.31
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	50	50	98.66	197.31
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	81.72	102.15
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	81.19	101.49
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	92	115
Y102/Y104 (West Royalty - Marshfield)	T2 (Crossroad - Charlottetown)	80	80	91.25	114.06
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	87.72	116.96
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	58.78	117.56
Y102/Y104 (West Royalty - Marshfield)	T13 (West Royalty Tap - UPEI)	80	80	84.25	105.32
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	50	50	58.78	117.56

A.1.3 SCENARIO 3

Table 10 shows the thermal criteria violations identified in Scenario 3.

Table 10 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 3					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	145.08	130.71
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	145.08	130.71
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.57	123.43
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	50	50	62.03	124.05
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.57	123.43
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.03	124.05
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	74.83	149.65
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	50	50	74.83	149.65
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	86.66	173.32
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	91.86	122.49
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	81.13	101.42

A.1.4 SCENARIO 4

Table 11 shows the thermal criteria violations identified in Scenario 4.

Table 11 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	54.06	108.13
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	50	50	54.06	108.13
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	72.88	145.76
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	78.07	104.1
Y102/Y104 (West Royalty - Marshfield)	T2 (Crossroad - Charlottetown)	80	80	103.34	129.18
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	76.15	101.53
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	51.03	102.05
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	50	50	51.03	102.05

A.1.5 SCENARIO 5

Table 12 shows the thermal criteria violations identified in Scenario 5.

Table 12 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 5					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	146.94	132.38
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	146.94	132.38
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	82.32	109.77
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	75	82.32	109.77
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	96.8	129.07
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	64.86	129.72
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	64.86	129.72
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	75	96.8	129.07
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	86.18	172.36
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	91.55	122.07
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	81.1	101.37

A.1.6 SCENARIO 6

Table 13 shows the thermal criteria violations identified in Scenario 6.

Table 13 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 6

Contingency (System Element Lost)	Violation Location Details	Thermal Ratings (MVA)		Results	
		Normal Rating	Emergency Rating	Power Flow (MVA)	% Loading
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	80.8	161.61
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	85.99	114.66

A.1.7 SCENARIO 7

Table 14 shows the thermal criteria violations identified in Scenario 7.

Table 14 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 7

Contingency (System Element Lost)	Violation Location Details	Thermal Ratings (MVA)		Results	
		Normal Rating	Emergency Rating	Power Flow (MVA)	% Loading
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	157.12	141.55
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	157.12	141.55
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	83.08	110.77
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	75	83.08	110.77

Table 14 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 7					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	97.54	130.06
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.36	130.72
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.36	130.72
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	75	97.54	130.06
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	95.74	191.49
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	101.42	135.23
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	81.01	101.26

A.1.8 SCENARIO 8

Table 15 shows the thermal criteria violations identified in Scenario 8.

Table 15 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 8					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	84.06	168.11

Table 15 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 8					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	89.46	119.28

A.1.9 SCENARIO 9

Table 16 shows the thermal criteria violations identified in Scenario 9.

Table 16 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 9					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	51.62	103.25
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	50	50	51.62	103.25

A.1.10 SCENARIO 10

There were no thermal criteria violations under N-0 and N-1 conditions for Scenario 10.

A.1.11 SCENARIO 11

Table 17 shows the thermal criteria violations identified in Scenario 11.

Table 17 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 11					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	20	50.95	101.9

A.1.12 SCENARIO 12

Table 18 shows the thermal criteria violations identified in Scenario 12.

Table 18 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 12					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	129.04	116.25
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	129.04	116.25
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	50.07	100.14
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	50.07	100.14
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	100.11	200.23
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	106.43	141.91

A.1.13 SCENARIO 13

Table 19 shows the thermal criteria violations identified in Scenario 13.

Table 19 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13

Contingency (System Element Lost)	Violation Location Details	Thermal Ratings (MVA)		Results	
		Normal Rating	Emergency Rating	Power Flow (MVA)	% Loading
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.31	125.74
System Normal	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.19	126.38
System Normal	T13 (West Royalty Tap - UPEI)	80	80	80.64	100.8
System Normal	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.31	125.74
System Normal	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	123.72	111.46
System Normal	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	123.72	111.46
System Normal	Cable 3 (Cape Tormentine - Borden)	204	204	216.97	106.36
System Normal	Cable 4 (Cape Tormentine - Borden)	204	204	219.41	107.56
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	122.46	163.28
T3 (Westroy 138/69 kV Transformer T3)	T13 (West Royalty Tap - UPEI)	80	80	80.35	100.43
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	50	122.46	163.28
T3 (Westroy 138/69 kV Transformer T3)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	123.22	111.01
T3 (Westroy 138/69 kV Transformer T3)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	123.22	111.01

Table 19 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T3 (Westroy 138/69 kV Transformer T3)	Cable 3 (Cape Tormentine - Borden)	204	204	216.27	106.02
T3 (Westroy 138/69 kV Transformer T3)	Cable 4 (Cape Tormentine - Borden)	204	204	218.71	107.21
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	143.7	191.6
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96.29	192.57
T2 (Westroy 138/69 kV Transformer T2)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	123.21	111
T2 (Westroy 138/69 kV Transformer T2)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	123.21	111
T2 (Westroy 138/69 kV Transformer T2)	Cable 3 (Cape Tormentine - Borden)	204	204	216.29	106.02
T2 (Westroy 138/69 kV Transformer T2)	Cable 4 (Cape Tormentine - Borden)	204	204	218.73	107.22
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96.29	192.57
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	143.7	191.6
T1 (Westroy 138/69 kV Transformer T1)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	123.21	111
T1 (Westroy 138/69 kV Transformer T1)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	123.21	111

Table 19 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Westroy 138/69 kV Transformer T1)	Cable 3 (Cape Tormentine - Borden)	204	204	216.29	106.02
T1 (Westroy 138/69 kV Transformer T1)	Cable 4 (Cape Tormentine - Borden)	204	204	218.73	107.22
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.09	125.45
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.04	126.09
T1 (Sherbrooke 138/69 kV Transformer T1)	T13 (West Royalty Tap - UPEI)	80	80	84.03	105.04
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.09	125.45
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	105.86	211.72
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	122.81	110.64
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	122.81	110.64
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 3 (Cape Tormentine - Borden)	204	204	215.67	105.72
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 4 (Cape Tormentine - Borden)	204	204	218.1	106.91
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.15	125.53

Table 19 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.09	126.17
T2 (Sherbrooke 138/69 kV Transformer T2)	T13 (West Royalty Tap - UPEI)	80	80	82.85	103.57
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.15	125.53
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	123.1	110.9
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	123.1	110.9
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	112.88	150.51
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 3 (Cape Tormentine - Borden)	204	204	216.09	105.93
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 4 (Cape Tormentine - Borden)	204	204	218.52	107.12
T2 (Crossroad - Charlottetown)	T1 (Westroy 138/69 kV Transformer T1)	75	75	83.83	111.77
T2 (Crossroad - Charlottetown)	T3 (Westroy 138/69 kV Transformer T3)	50	50	56.17	112.34
T2 (Crossroad - Charlottetown)	T2 (Westroy 138/69 kV Transformer T2)	75	50	83.83	111.77
T2 (Crossroad - Charlottetown)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	122.67	110.51
T2 (Crossroad - Charlottetown)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	122.67	110.51

Table 19 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	85.42	113.89
T2 (Crossroad - Charlottetown)	Cable 3 (Cape Tormentine - Borden)	204	204	215.26	105.52
T2 (Crossroad - Charlottetown)	Cable 4 (Cape Tormentine - Borden)	204	204	217.68	106.71
T13 (Charlottetown North - UPEI)	T15 (Charlottetown - T15 Tap)	80	80	105.66	132.08
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	90.55	120.73
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	60.67	121.34
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	119.03	148.79
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	50	90.55	120.73
T13 (Charlottetown North - UPEI)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	123.27	111.06
T13 (Charlottetown North - UPEI)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	123.27	111.06
T13 (Charlottetown North - UPEI)	Cable 3 (Cape Tormentine - Borden)	204	204	216.39	106.07
T13 (Charlottetown North - UPEI)	Cable 4 (Cape Tormentine - Borden)	204	204	218.83	107.27
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	111.57	139.46
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.59	123.45
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.04	124.08
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	123.71	154.63

Table 19 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	50	92.59	123.45
T15 (Charlottetown North - T15 Tap)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	123.32	111.1
T15 (Charlottetown North - T15 Tap)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	123.32	111.1
T15 (Charlottetown North - T15 Tap)	Cable 3 (Cape Tormentine - Borden)	204	204	216.43	106.09
T15 (Charlottetown North - T15 Tap)	Cable 4 (Cape Tormentine - Borden)	204	204	218.87	107.29
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	124.51	155.64
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.27	123.02
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	61.82	123.65
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	138.17	172.71
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	50	92.27	123.02
T15 (T15 Tap - West Royalty)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	123.51	111.27
T15 (T15 Tap - West Royalty)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	123.51	111.27
T15 (T15 Tap - West Royalty)	Cable 3 (Cape Tormentine - Borden)	204	204	216.77	106.26
T15 (T15 Tap - West Royalty)	Cable 4 (Cape Tormentine - Borden)	204	204	219.21	107.46
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	97.32	129.76

Table 19 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.21	130.42
Y102/Y104 (West Royalty - Marshfield)	T13 (West Royalty Tap - UPEI)	80	80	86.84	108.55
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	50	97.32	129.76
Y102/Y104 (West Royalty - Marshfield)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	123.83	111.56
Y102/Y104 (West Royalty - Marshfield)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	123.83	111.56
Y102/Y104 (West Royalty - Marshfield)	Cable 3 (Cape Tormentine - Borden)	204	204	216.41	106.08
Y102/Y104 (West Royalty - Marshfield)	Cable 4 (Cape Tormentine - Borden)	204	204	218.85	107.28

A.1.14 SCENARIO 14

Table 20 shows the thermal criteria violations identified in Scenario 14.

Table 20 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 14					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	88.12	117.5
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	50	50	59.05	118.1
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	88.12	117.5
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	59.05	118.1
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	71.62	143.23
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	50	50	71.62	143.23
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	60.18	120.36

A.1.15 SCENARIO 15

Table 21 shows the thermal criteria violations identified in Scenario 15.

Table 21 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 15					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	64.38	128.76

A.1.16 SCENARIO 16

Table 22 shows the thermal criteria violations identified in Scenario 16.

Table 22 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 16					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	80.41	107.22
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	75	80.41	107.22
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.49	125.99
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.31	126.63
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.31	126.63
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	75	94.49	125.99
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	68.09	136.19

A.1.17 SCENARIO 17

Table 23 shows the thermal criteria violations identified in Scenario 17.

Table 23 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 17

Contingency (System Element Lost)	Violation Location Details	Thermal Ratings (MVA)		Results	
		Normal Rating	Emergency Rating	Power Flow (MVA)	% Loading
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	126.19	113.68
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	126.19	113.68
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	75.62	100.83
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	50.67	101.34
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	50.67	101.34
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	75.62	100.83
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	98.79	197.59
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	104.94	139.92

A.1.18 SCENARIO 18

Table 24 shows the thermal criteria violations identified in Scenario 18.

Table 24 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
SYSTEM NORMAL	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.36	125.82
SYSTEM NORMAL	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.23	126.46
SYSTEM NORMAL	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.36	125.82
SYSTEM NORMAL	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	125.98	113.49
SYSTEM NORMAL	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	125.98	113.49
SYSTEM NORMAL	Cable 3 (Cape Tormentine - Borden)	204	204	217.65	106.69
SYSTEM NORMAL	Cable 4 (Cape Tormentine - Borden)	204	204	220.11	107.9
CABLE 1 (Murray Corner - Richcove/Fernwood)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.57	124.77
CABLE 1 (Murray Corner - Richcove/Fernwood)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.7	125.4
CABLE 1 (Murray Corner - Richcove/Fernwood)	T13 (West Royalty Tap - UPEI)	80	80	83.62	104.52
CABLE 1 (Murray Corner - Richcove/Fernwood)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.57	124.77
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	234.29	211.08
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 3 (Cape Tormentine - Borden)	204	204	232.31	113.88
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 4 (Cape Tormentine - Borden)	204	204	234.92	115.16

Table 24 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 2 (Murray Corner - Richcove/Fernwood)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.57	124.77
CABLE 2 (Murray Corner - Richcove/Fernwood)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.7	125.4
CABLE 2 (Murray Corner - Richcove/Fernwood)	T13 (West Royalty Tap - UPEI)	80	80	83.62	104.52
CABLE 2 (Murray Corner - Richcove/Fernwood)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.57	124.77
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	234.29	211.08
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 3 (Cape Tormentine - Borden)	204	204	232.31	113.88
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 4 (Cape Tormentine - Borden)	204	204	234.92	115.16
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	122.5	163.33
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	50	122.5	163.33
T3 (Westroy 138/69 kV Transformer T3)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	125.87	113.4
T3 (Westroy 138/69 kV Transformer T3)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	125.87	113.4
T3 (Westroy 138/69 kV Transformer T3)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	77.53	103.38
T3 (Westroy 138/69 kV Transformer T3)	Cable 3 (Cape Tormentine - Borden)	204	204	217.54	106.64
T3 (Westroy 138/69 kV Transformer T3)	Cable 4 (Cape Tormentine - Borden)	204	204	219.99	107.84

Table 24 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	143.57	191.43
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96.2	192.4
T2 (Westroy 138/69 kV Transformer T2)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	125.84	113.37
T2 (Westroy 138/69 kV Transformer T2)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	125.84	113.37
T2 (Westroy 138/69 kV Transformer T2)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	81.86	109.14
T2 (Westroy 138/69 kV Transformer T2)	Cable 3 (Cape Tormentine - Borden)	204	204	217.54	106.64
T2 (Westroy 138/69 kV Transformer T2)	Cable 4 (Cape Tormentine - Borden)	204	204	219.99	107.84
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96.2	192.4
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	143.57	191.43
T1 (Westroy 138/69 kV Transformer T1)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	125.84	113.37
T1 (Westroy 138/69 kV Transformer T1)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	125.84	113.37
T1 (Westroy 138/69 kV Transformer T1)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	81.86	109.14
T1 (Westroy 138/69 kV Transformer T1)	Cable 3 (Cape Tormentine - Borden)	204	204	217.54	106.64
T1 (Westroy 138/69 kV Transformer T1)	Cable 4 (Cape Tormentine - Borden)	204	204	219.99	107.84
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.1	125.46

Table 24 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.05	126.1
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.1	125.46
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	103.99	207.98
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	125.56	113.12
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	125.56	113.12
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 3 (Cape Tormentine - Borden)	204	204	217.16	106.45
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 4 (Cape Tormentine - Borden)	204	204	219.61	107.65
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.22	125.63
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.13	126.27
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.22	125.63
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	125.75	113.29
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	125.75	113.29

Table 24 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	111.2	148.27
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 3 (Cape Tormentine - Borden)	204	204	217.38	106.56
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 4 (Cape Tormentine - Borden)	204	204	219.83	107.76
T2 (Crossroad - Charlottetown)	T1 (Westroy 138/69 kV Transformer T1)	75	75	82.11	109.48
T2 (Crossroad - Charlottetown)	T3 (Westroy 138/69 kV Transformer T3)	50	50	55.02	110.03
T2 (Crossroad - Charlottetown)	T2 (Westroy 138/69 kV Transformer T2)	75	50	82.11	109.48
T2 (Crossroad - Charlottetown)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	126.84	114.27
T2 (Crossroad - Charlottetown)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	126.84	114.27
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	108.04	144.06
T2 (Crossroad - Charlottetown)	Cable 3 (Cape Tormentine - Borden)	204	204	218.94	107.32
T2 (Crossroad - Charlottetown)	Cable 4 (Cape Tormentine - Borden)	204	204	221.41	108.53
T13 (Charlottetown North - UPEI)	T15 (Charlottetown - T15 Tap)	80	80	91.8	114.76
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	91.42	121.9
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	61.26	122.52
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	107.95	134.93

Table 24 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	50	91.42	121.9
T13 (Charlottetown North - UPEI)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	126.04	113.55
T13 (Charlottetown North - UPEI)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	126.04	113.55
T13 (Charlottetown North - UPEI)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	79.05	105.4
T13 (Charlottetown North - UPEI)	Cable 3 (Cape Tormentine - Borden)	204	204	217.83	106.78
T13 (Charlottetown North - UPEI)	Cable 4 (Cape Tormentine - Borden)	204	204	220.29	107.98
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	95.78	119.72
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93	124
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.31	124.63
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	111.44	139.29
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93	124
T15 (Charlottetown North - T15 Tap)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	126.04	113.55
T15 (Charlottetown North - T15 Tap)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	126.04	113.55
T15 (Charlottetown North - T15 Tap)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	75.07	100.1
T15 (Charlottetown North - T15 Tap)	Cable 3 (Cape Tormentine - Borden)	204	204	217.78	106.76
T15 (Charlottetown North - T15 Tap)	Cable 4 (Cape Tormentine - Borden)	204	204	220.24	107.96

Table 24 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	111.24	139.05
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.59	123.45
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.04	124.08
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	127.89	159.87
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	50	92.59	123.45
T15 (T15 Tap - West Royalty)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	126.2	113.7
T15 (T15 Tap - West Royalty)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	126.2	113.7
T15 (T15 Tap - West Royalty)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	76.49	101.98
T15 (T15 Tap - West Royalty)	Cable 3 (Cape Tormentine - Borden)	204	204	218.07	106.9
T15 (T15 Tap - West Royalty)	Cable 4 (Cape Tormentine - Borden)	204	204	220.53	108.1
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	97.5	130.01
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.33	130.67
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	50	97.5	130.01
Y102/Y104 (West Royalty - Marshfield)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	126.33	113.81
Y102/Y104 (West Royalty - Marshfield)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	126.33	113.81
Y102/Y104 (West Royalty - Marshfield)	Cable 3 (Cape Tormentine - Borden)	204	204	217.57	106.65

Table 24 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
Y102/Y104 (West Royalty - Marshfield)	Cable 4 (Cape Tormentine - Borden)	204	204	220.03	107.86

A.1.19 SCENARIO 20

There were no thermal criteria violations under N-0 and N-1 conditions for Scenario 20.

A.1.20 SCENARIO 21

There were no thermal criteria violations under N-0 and N-1 conditions for Scenario 21.

A.1.21 SCENARIO 22

There were no thermal criteria violations under N-0 and N-1 conditions for Scenario 22.

Appendix B Reactive Power Support Devices for PEI Existing Intertie System

Table 25 shows the reactive power devices added in the study scenarios with existing intertie system.

Table 25 Reactive Power Support Summary by Study Scenarios, Locations, and Regions

Scenario #	Location where Reactive Power Device Added	Reactive Power Device Size (MVAR)	Area
12	Borden	20	Central
13	West Royalty	20	City
	Borden (SVC)	81	Central
	Bedeque	50	Central
	Sherbrooke	40	West
	Sherbrooke (SVC)	40	West
	Alberton	10	West
	Charlottetown	50	City
	Cross Roads	20	East
	Dingwell Mills	20	East
	Victoria Cross	20	East
	Victoria Cross	20	East
	Dingwell Mills	15	East
	Victoria Cross	20	East
18	West Royalty	50	City
	Borden	20	Central
	Church Road	10	East
	Clyde River Tap	30	Central
	Borden	60	Central
	Bedeque	40	Central
	Sherbrooke	20	West
	Sherbrooke	20	West
	Alberton	20	West
	West Royalty	20	City
	Charlottetown	30	City
	Cross Roads	30	East
	Dingwell Mills	20	East
	Victoria Cross	25	East

Appendix C Short Circuit Current Results for PEI Existing Intertie System

C.1 Short-Circuit Current Results

Short-circuit studies were performed using the ASPEN model provided by Maritime Electric. Table 26 shows the short-circuit fault level for Scenario 11.

Table 26 Short-circuit Fault Levels for Scenario 11

PSSE®E Bus #	Bus Name	Voltage Level (kV)	3-Phase Fault Current (Amps)	Line-to-Line-Ground Fault Current (Amps)	Single Line-to-Ground Fault Current (Amps)	Line-to-Line Fault Current (Amps)
2256	Aeolus	69	1584	1536	1354	1356
2799	Airport	24.94	4013	4159	4256	3481
2699	Airport	69	6285	5964	5286	5486
2267	Albany	69	3444	3339	3135	2983
2280	Alberton	69	1845	1700	1321	1584
2286	Bagnall Rd	69	3671	3323	2194	3186
-	Bagnall Rd Tap	69	4367	3965	2727	3792
2271	Bedeque	138	7992	7574	6783	6943
-	Bonshaw	24.94	4900	4591	4053	4252
2269	Borden	69	4675	5262	5481	4051
2270	Borden	138	8667	8294	7617	7529
-	Ch_town_43	69	7468	7658	7676	6550
228502	Ch_townP000	69	7474	7668	7689	6555
2285	Ch_townPlant	69	7474	7668	7689	6555
-	Christ.Cross	69	1776	1722	1532	1518
2299	Church Road	69	3610	4136	4231	3132
2199	Church Road	138	2435	2543	2513	2113
2498	Clyde River	24.94	4293	4478	4570	3720
2298	Clyde River	138	4257	3962	3318	3700
2289	Cross Roads	69	5930	5574	4827	5183
2297	Dover	69	1364	1250	785	1182
2398	Elmira	34.5	4675	5021	5150	4050
2198	Elmira	138	1884	1934	1879	1634

Table 26 Short-circuit Fault Levels for Scenario 11						
PSSE®E Bus #	**Bus Name**	**Voltage Level (kV)**	**3-Phase Fault Current (Amps)**	**Line-to-Line-Ground Fault Current (Amps)**	**Single Line-to-Ground Fault Current (Amps)**	**Line-to-Line Fault Current (Amps)**
2292	Georgetown	69	2560	2297	1477	2221
2	Georgetown_Dingw	69	3486	3131	2158	3026
2113	Hermanville	138	1996	2098	2074	1731
2290	Lorne Valley	69	3683	3290	2184	3198
-	LornevyC3-C4	69	3680	3288	2182	3196
-	Marshfield	138	4128	3917	3462	3589
2268	McCain	69	4363	4627	4777	3780
-	Memramcook	138	31492	34614	36135	27496
-	MiltonBrack	24.94	6815	7503	7828	5919
258	MurrayCorner	138	6993	6620	5304	6071
2257	North Cape	69	1494	1394	1134	1280
2258	Norway	69	1677	1652	1492	1434
-	Norway Coll	34.5	2013	2177	2259	1734
2282	Rattenbury	69	4321	3922	2703	3749
-	Reactors	138	7992	7573	6783	6943
2259	Richmond Cove	138	6673	6254	5051	5793
2288	Scotchfort	69	1793	1636	1035	1554
-	Sherbro_Welling	138	5581	5292	4670	4842
2275	Sherbrooke	69	7366	7773	7787	6384
2274	Sherbrooke	138	6486	6312	5865	5630
2294	Souris	69	1965	1790	1282	1703
5001	St.Eleanors_GND	69	5576	5240	4512	4828
192476	Summerside345	34.5	8023	10284	10441	6951
2276	Summerside	69	6137	5756	4996	5318
192576	SummersideWF	34.5	3116	4612	4335	2699
2210	Tignish	69	1778	1701	1485	1521
1901471	Tormentine	138	7711	7590	6831	6696
1901472	Tormentine1	138	7691	7573	6820	6678
2700	UPEI	69	7437	7415	7257	6507
2396	VictoriaCros	24.94	1662	1854	1905	1440
2296	VictoriaCros	69	2164	1967	1254	1877

Table 26 Short-circuit Fault Levels for Scenario 11						
PSSE®E Bus #	**Bus Name**	**Voltage Level (kV)**	**3-Phase Fault Current (Amps)**	**Line-to-Line-Ground Fault Current (Amps)**	**Single Line-to-Ground Fault Current (Amps)**	**Line-to-Line Fault Current (Amps)**
-	W.St Peters_40	138	2981	2788	2356	2589
2255	Weican	69	1750	1722	1557	1495
2278	Wellington	69	3372	3060	2167	2914
-	Wellington	138	3910	3627	2999	3391
2112	West Cape	138	2026	2196	2256	1755
2584	West Royalty	24.94	6856	7610	7940	5954
2284	West Royalty	69	8283	8973	9196	7241
2295	West Royalty	138	5360	5486	5393	4666
-	West Cape35	34.5	6442	8917	8801	5581
22841	West Royalty	69	8283	8973	9196	7241
-	WestRoyalty2	138	5330	5457	5370	4640
-	WestRoyalty3	138	5373	5502	5411	4678
-	WR_HR_SW176	69	8223	8899	9116	7188
125	Y102WR	138	5277	5402	5316	4594
-	Y105SHERB-730	138	6478	6301	5849	5623
-	Y107BED-517	138	7975	7557	6769	6927
-	Y107BOR-304	138	8585	8219	7553	7457
-	Y111BED-542	138	7895	7488	6719	6858
-	Y111BED-700	138	7879	7474	6705	6844
-	Y111YR-117	138	5355	5478	5382	4661
-	Y113SBOR-301	138	8529	8169	7514	7409
-	Y113SHERB-700	138	6458	6283	5835	5605
-	Y115SHERB	138	6400	6229	5796	5554

Table 27 shows the short-circuit fault levels for Scenario 13.

Table 27 Short-circuit Fault Levels for Scenario 13						
PSS®E Bus #	**Bus Name**	**Voltage Level (kV)**	**3-Phase Fault Current (Amps)**	**Line-to-Line-Ground Fault Current (Amps)**	**Single Line-to-Ground Fault Current (Amps)**	**Line-to-Line Fault Current (Amps)**
2256	Aeolus	69	833	928	911	721
2799	Airport	24.94	3815	4064	4180	3305
2699	Airport	69	4332	4391	4309	3754
2267	Albany	69	2691	2733	2734	2331
2280	Alberton	69	1095	1103	1022	948
2286	Bagnall Rd	69	3134	2874	2136	2715
-	Bagnall Rd_Tap	69	3588	3315	2595	3109
2271	Bedeque	138	5938	5871	5761	5151
-	Bonshaw	24.94	4572	4354	4011	3960
2269	Borden	69	3340	4110	4218	2894
2270	Borden	138	6397	6414	6395	5550
-	Ch_town_43	69	4440	5172	5286	3848
228502	Ch_townP000	69	4442	5178	5292	3850
2285	Ch_townPlant	69	4442	5178	5292	3850
-	Christ.Cross	69	906	1020	1006	785
2299	Church Road	69	2577	3248	3263	2232
2199	Church Road	138	1577	1840	1859	1367
2498	Clyde River	24.94	4232	4488	4591	3666
2298	Clyde River	138	3234	3146	2910	2803
2289	Cross Roads	69	3820	3880	3796	3310
2297	Dover	69	1179	1096	777	1021
2398	Elmira	34.5	2821	3454	3521	2443
2198	Elmira	138	1223	1400	1408	1059
2292	Georgetown	69	1906	1766	1364	1651
2	Georgetown_Dingw	69	2333	2204	1865	2021
2113	Hermanville	138	1287	1516	1527	1115
2290	Lorne Valley	69	2368	2230	1866	2052
-	LornevyC3-C4	69	2367	2229	1864	2051
-	Marshfield	138	2899	2940	2854	2513
2268	McCain	69	3185	3639	3809	2759
-	Memramcook	138	29628	33066	34578	25874

Table 27 Short-circuit Fault Levels for Scenario 13						
PSS®E Bus #	**Bus Name**	**Voltage Level (kV)**	**3-Phase Fault Current (Amps)**	**Line-to-Line-Ground Fault Current (Amps)**	**Single Line-to-Ground Fault Current (Amps)**	**Line-to-Line Fault Current (Amps)**
-	MiltonBrack	24.94	6061	6983	7239	5251
258	MurrayCorner	138	5660	5490	4822	4909
2257	North Cape	69	807	846	810	699
2258	Norway	69	859	984	969	744
-	Norway Coll	34.5	1151	1409	1440	997
2282	Rattenbury	69	3590	3314	2588	3110
-	Reactors	138	5938	5871	5761	5151
2259	Richmond Cove	138	5353	5128	4571	4643
2288	Scotchfort	69	1456	1355	996	1261
-	Sherbro_Welling	138	4264	4253	4063	3697
2275	Sherbrooke	69	5224	6020	6144	4527
2274	Sherbrooke	138	4797	4975	4921	4160
2294	Souris	69	1641	1532	1228	1422
5001	St.Eleanors_GND	69	4174	4123	3929	3617
192476	Summerside345	34.5	6381	8716	8612	5529
2276	Summerside	69	4383	4382	4233	3798
192576	Summerside WF	34.5	2714	4138	3833	2351
2210	Tignish	69	930	1022	1004	805
1901471	Tormentine	138	6080	6196	5976	5275
1901472	Tormentine1	138	6065	6185	5967	5262
2700	UPEI	69	4685	5197	5323	4060
2396	VictoriaCros	24.94	1627	1864	1910	1409
2296	VictoriaCros	69	1670	1556	1178	1446
-	W.St Peters_40	138	2109	2096	1981	1828
2255	Weican	69	884	1017	1003	766
2278	Wellington	69	2597	2430	1991	2250
-	Wellington	138	3149	3027	2732	2730
2112	West Cape	138	1600	1859	1907	1386
2584	West Royalty	24.94	6091	7078	7329	5277
2284	West Royalty	69	5243	6380	6492	4544
2295	West Royalty	138	3622	4073	4132	3140

Table 27 Short-circuit Fault Levels for Scenario 13						
PSS®E Bus #	**Bus Name**	**Voltage Level (kV)**	**3-Phase Fault Current (Amps)**	**Line-to-Line-Ground Fault Current (Amps)**	**Single Line-to-Ground Fault Current (Amps)**	**Line-to-Line Fault Current (Amps)**
-	West Cape35	34.5	4618	6804	6500	4000
22841	West Royalty	69	5243	6380	6492	4544
-	WestRoyalty2	138	3596	4048	4108	3118
-	WestRoyalty3	138	3624	4079	4138	3141
-	WR_HR_SW176	69	5223	6344	6457	4527
125	Y102WR	138	3568	4014	4073	3093
-	Y105SHERB-730	138	4801	4974	4916	4163
-	Y107BED-517	138	5934	5865	5754	5147
-	Y107BOR-304	138	6349	6368	6349	5509
-	Y111BED-542	138	5878	5815	5712	5099
-	Y111BED-700	138	5867	5803	5701	5090
-	Y111YR-117	138	3623	4071	4129	3141
-	Y113SBOR-301	138	6317	6336	6320	5480
-	Y113SHERB-700	138	4789	4963	4905	4153
-	Y115SHERB	138	4748	4924	4872	4118

Appendix D Dynamic Results for PEI Existing Intertie System

D.1 Dynamic Study Results

Stantec performed dynamic study for the selected scenarios.

D.1.1 STUDIED CONTINGENCIES

Table 28 shows the list of contingencies used in dynamic study.

Table 28 Contingency Used in Dynamic Study

#	Contingency Type	Contingency Description
1	138 kV Cable	Cable 2
2	138 kV Cable	Cable 3
3	138 kV Transmission Line	Bedeque - West Royalty
4	138 kV Transmission Line	Bedeque - Scotchfort
5	138 kV Transmission Line	Scotchfort – Lorne Valley
6	138 kV Transmission Line	West Royalty – Marshfield
7	138 kV Transmission Line	Charlottetown plant - Crossroad T2
8	138 kV Transmission Line	WSTOCK138 138.00 - Y115SHERB 138.00
9	Generator	CT2
10	Generator	CT3
11	Generator	West Cape Wind
12	Generator	Hermanville Wind
13	138 kV Transmission	Connection Option for each intertie alternative

The dynamic study results are presented in the following sections for Scenarios 11 and 13.

D.1.2 SCENARIO 11

Figure 5 - Figure 8 show the dynamic plots for the contingency of 138 kV transmission line between West Royalty and Marshfield.

Figure 5 138 kV Branch Active Power Flows

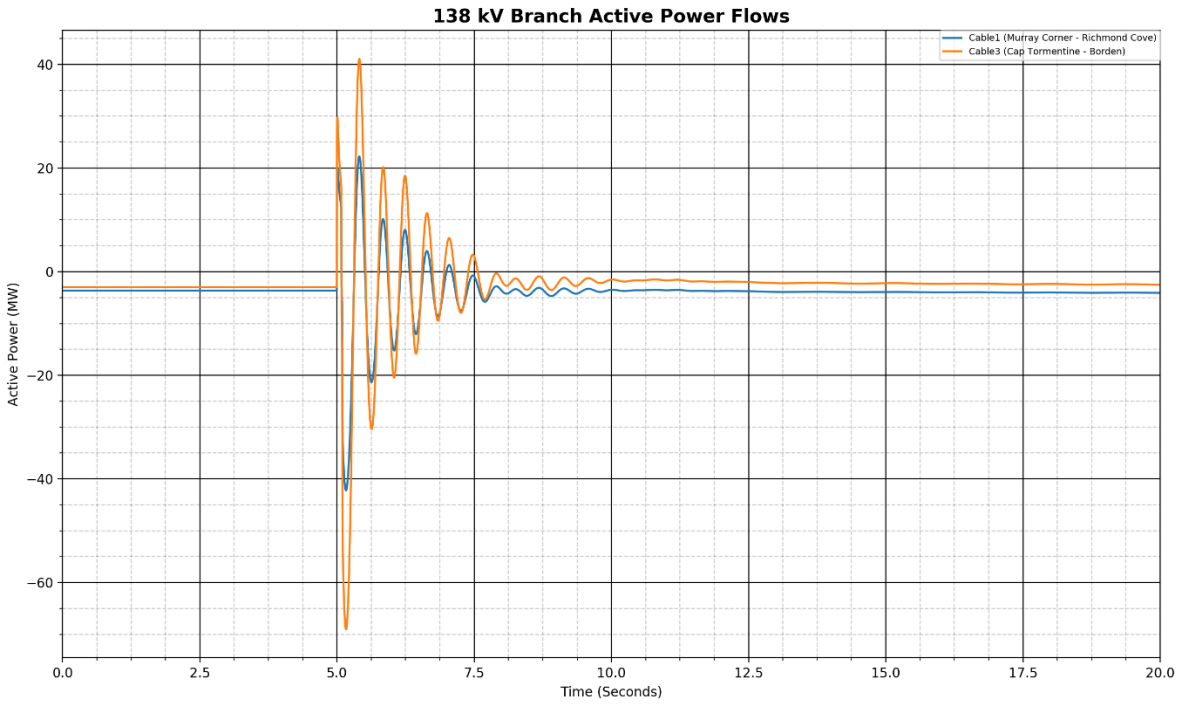


Figure 6 138 kV Branch Reactive Power Flows

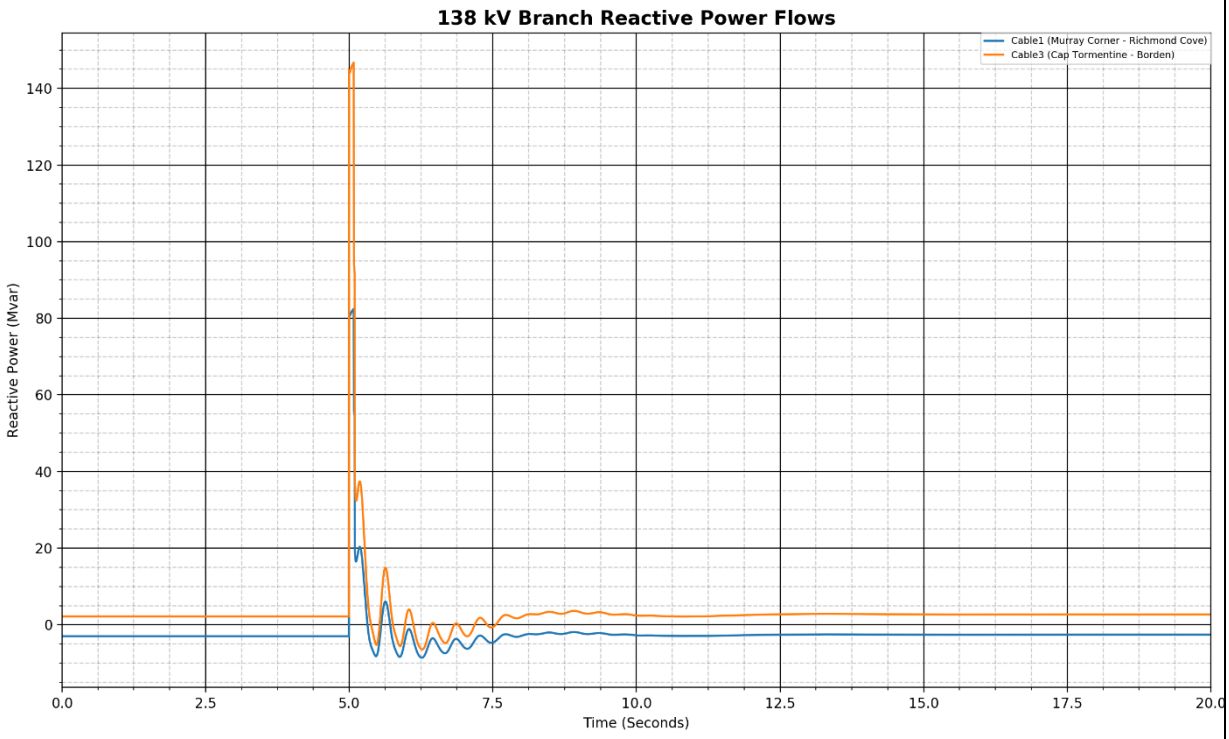


Figure 7 138 kV Frequencies

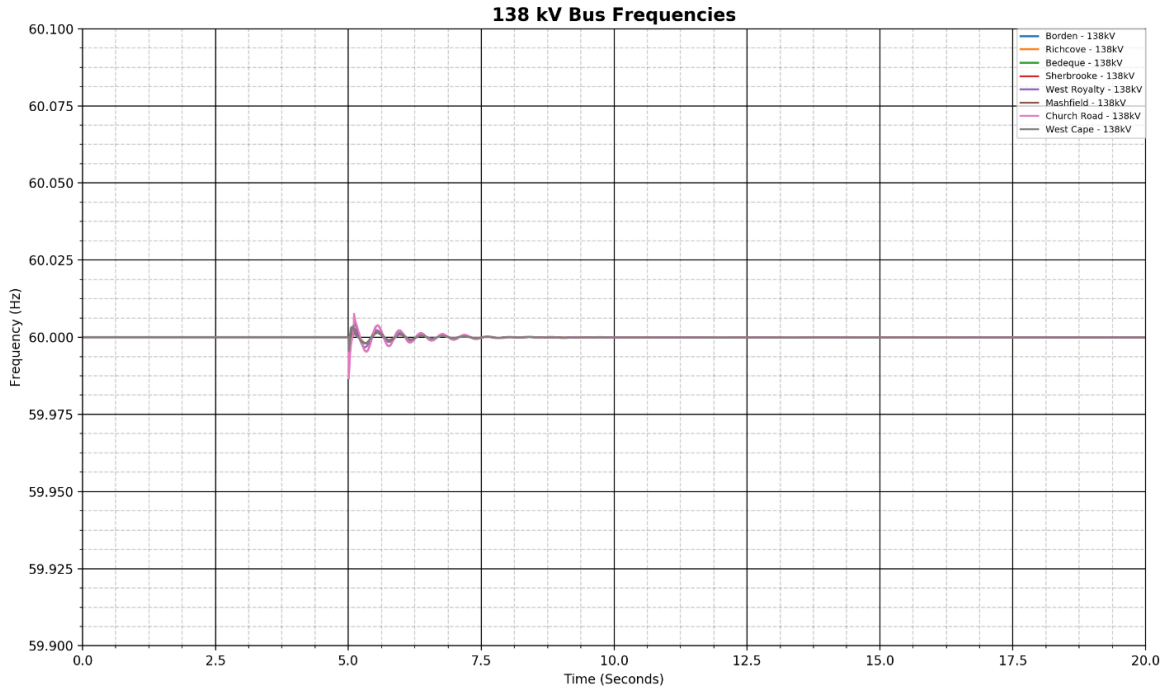
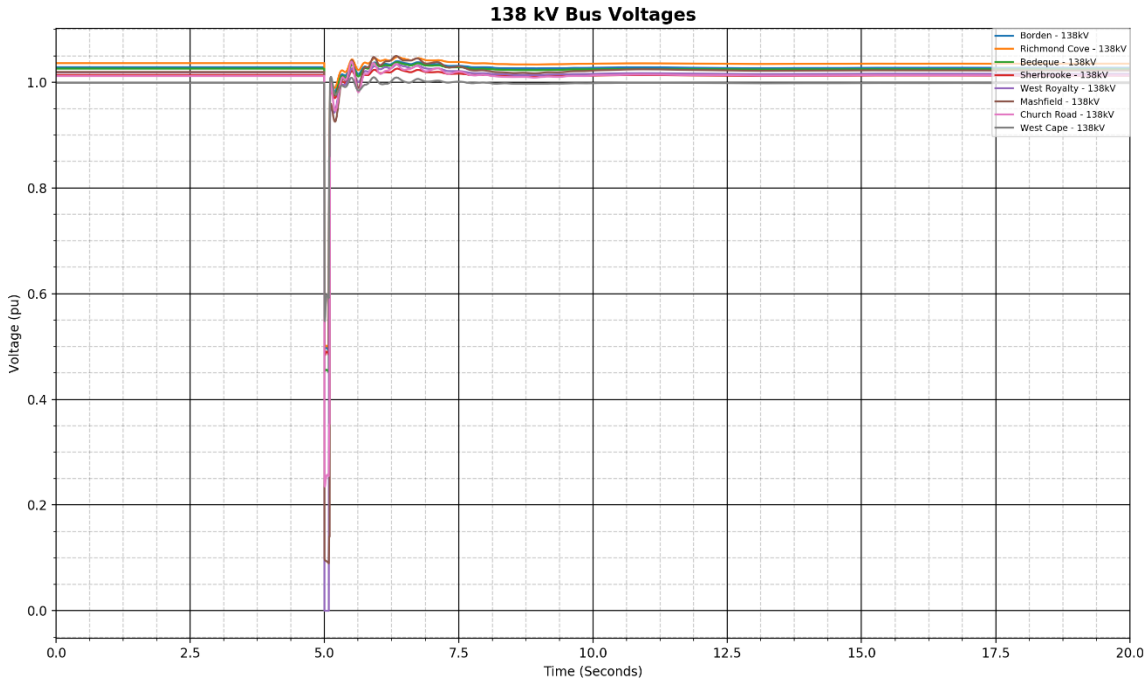


Figure 8 138 kV Bus Voltges



D.1.3 SCENARIO 13

Figure 9 - Figure 12 show the dynamic plots for the contingency of Cable 2.

Figure 9 138 kV Branch Active Power Flows

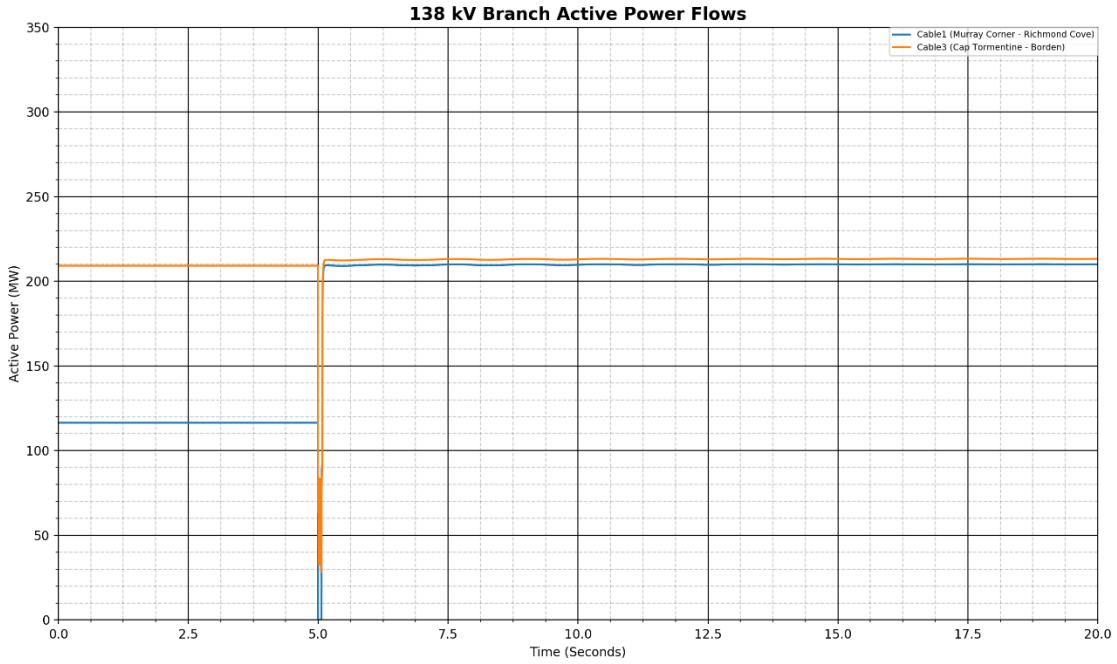


Figure 10 138 kV Branch Reactive Power Flows

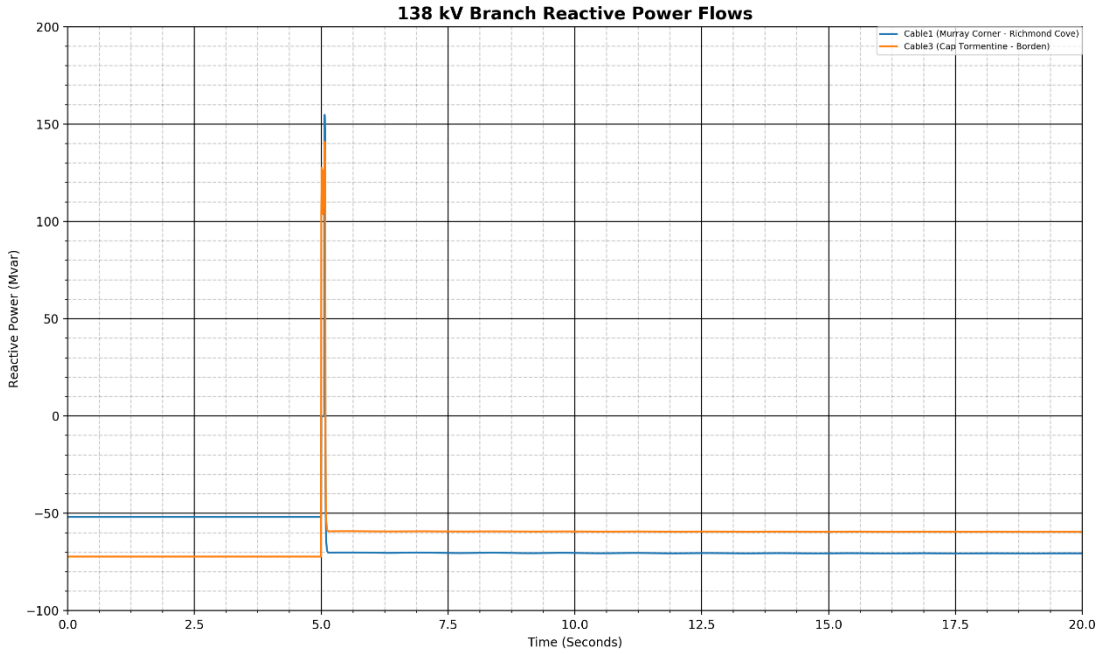


Figure 11 138 kV Frequencies

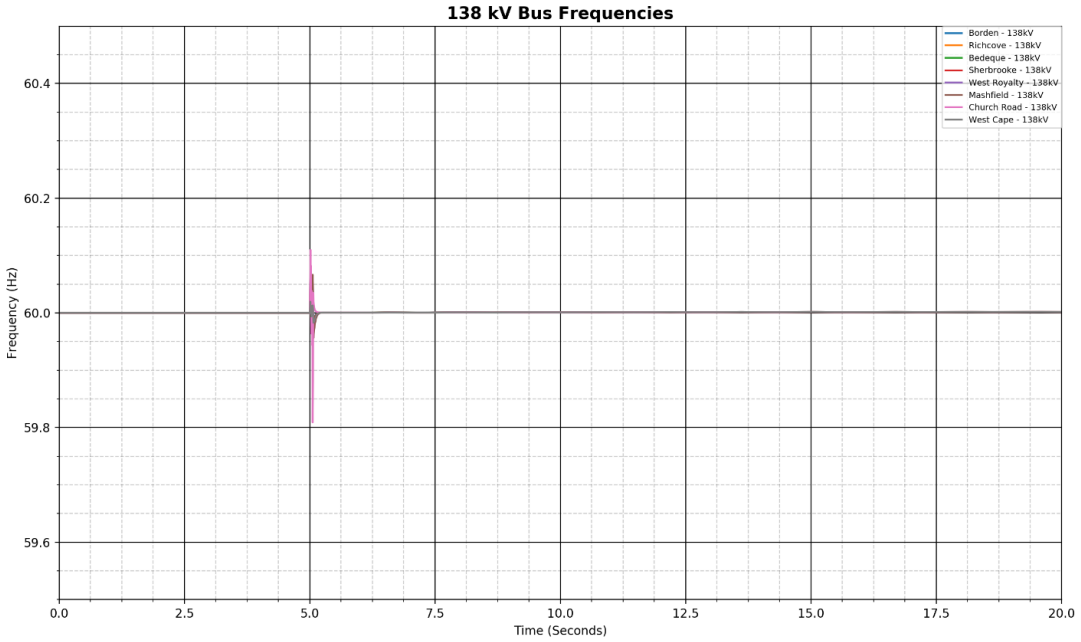
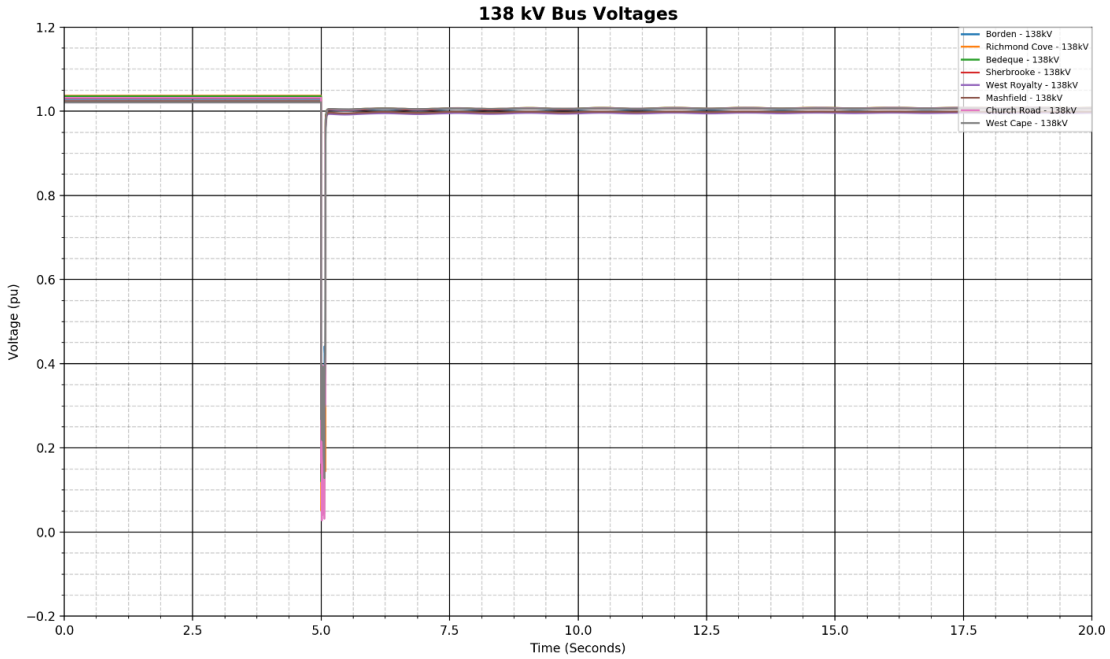


Figure 12 138 kV Bus Voltages



Appendix E Power Flow Results for PEI Proposed Intertie Scenarios

E.1 Power Flow Results

The tables below present the power flow results for PEI proposed intertie scenarios.

E.1.1 SCENARIO 12 ALTERNATIVE 1

Table 29 shows the thermal criteria violations identified in Scenario 12 Alternative 1.

Table 29 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 12 Alternative 1

Contingency (System Element Lost)	Violation Location Details	Thermal Ratings (MVA)		Results	
		Normal Rating	Emergency Rating	Power Flow (MVA)	% Loading
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	99.67	199.34
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	105.94	141.26

E.1.2 SCENARIO 12 ALTERNATIVE 2

Table 30 shows the thermal criteria violations identified in Scenario 12 Alternative 2.

Table 30 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 12 Alternate 2

Contingency (System Element Lost)	Violation Location Details	Thermal Ratings (MVA)		Results	
		Normal Rating	Emergency Rating	Power Flow (MVA)	% Loading
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	99.99	199.98
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	106.28	141.71

E.1.3 SCENARIO 13C

Table 31 shows the thermal criteria violations identified in Scenario 13C.

Table 31 hermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13C

Contingency (System Element Lost)	Violation Location Details	Thermal Ratings (MVA)		Results	
		Normal Rating	Emergency Rating	Power Flow (MVA)	% Loading
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	95.11	126.81
System Normal	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.73	127.46
System Normal	T2 (Westroy 138/69 kV Transformer T2)	75	50	119.85	159.8
System Normal	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.86	105.73
System Normal	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	78.89	105.19
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	122.74	163.66
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	50	142.69	190.26
T3 (Westroy 138/69 kV Transformer T3)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.61	105.22
T3 (Westroy 138/69 kV Transformer T3)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	78.51	104.68
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	143.66	191.55
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96.26	192.52
T2 (Westroy 138/69 kV Transformer T2)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	53.01	106.03

Table 31 hermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13C					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Westroy 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	79.12	105.49
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96	192
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	161.13	214.84
T1 (Westroy 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.41	104.82
T1 (Westroy 138/69 kV Transformer T1)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	78.22	104.29
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	95.18	126.9
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.77	127.55
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	115.96	154.62
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	119.3	238.6
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	95.13	126.84
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.74	127.49
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	50	118.26	157.68

Table 31 hermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13C					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	125.3	167.06
T2 (Crossroad - Charlottetown)	T1 (Westroy 138/69 kV Transformer T1)	75	75	84.68	112.9
T2 (Crossroad - Charlottetown)	T3 (Westroy 138/69 kV Transformer T3)	50	50	56.74	113.48
T2 (Crossroad - Charlottetown)	T2 (Westroy 138/69 kV Transformer T2)	75	50	105.1	140.14
T2 (Crossroad - Charlottetown)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.55	105.11
T2 (Crossroad - Charlottetown)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	78.43	104.57
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	86.46	115.29
T13 (Charlottetown North - UPEI)	T15 (Charlottetown - T15 Tap)	80	80	91.11	113.89
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	91.67	122.22
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	61.42	122.84
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	107.36	134.2
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	50	117.39	156.53
T13 (Charlottetown North - UPEI)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.66	105.32
T13 (Charlottetown North - UPEI)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	78.59	104.79
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	93.86	117.32
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.67	124.89

Table 31 hermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13C					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.76	125.52
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	109.68	137.09
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	50	118.75	158.34
T15 (Charlottetown North - T15 Tap)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.81	105.61
T15 (Charlottetown North - T15 Tap)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	78.81	105.08
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	110.1	137.63
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.35	124.47
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.55	125.11
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	126.84	158.55
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	50	118.07	157.43
T15 (T15 Tap - West Royalty)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.77	105.53
T15 (T15 Tap - West Royalty)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	78.75	105
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	97.67	130.22
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.44	130.88
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	50	121.74	162.32

Table 31 hermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13C					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
Y102/Y104 (West Royalty - Marshfield)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.85	105.71
Y102/Y104 (West Royalty - Marshfield)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	78.88	105.17

E.1.4 SCENARIO 13D

Table 32 shows the thermal criteria violations identified in Scenario 13D.

Table 32 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13D					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T2 (Crossroad - Charlottetown)	80	80	88.28	110.35
System Normal	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	53.3	106.59
System Normal	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	79.54	106.05
System Normal	L1 (New Landing Point - Dover)	204	204	213.22	104.52
CABLE 1 (Murray Corner - Richcove/Fernwood)	T2 (Crossroad - Charlottetown)	80	80	90.16	112.7
CABLE 1 (Murray Corner - Richcove/Fernwood)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.5	104.99
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	139.82	125.97

Table 32 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13D					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 1 (Murray Corner - Richcove/Fernwood)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	78.35	104.46
CABLE 1 (Murray Corner - Richcove/Fernwood)	T10 (Victoria Cross - Dover)	204	204	206.4	101.18
CABLE 1 (Murray Corner - Richcove/Fernwood)	L1 (New Landing Point - Dover)	204	204	216.01	105.89
CABLE 2 (Murray Corner - Richcove/Fernwood)	T2 (Crossroad - Charlottetown)	80	80	90.16	112.7
CABLE 2 (Murray Corner - Richcove/Fernwood)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.5	104.99
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	139.82	125.97
CABLE 2 (Murray Corner - Richcove/Fernwood)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	78.35	104.46
CABLE 2 (Murray Corner - Richcove/Fernwood)	T10 (Victoria Cross - Dover)	204	204	206.4	101.18
CABLE 2 (Murray Corner - Richcove/Fernwood)	L1 (New Landing Point - Dover)	204	204	216.01	105.89
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T2 (Crossroad - Charlottetown)	80	80	99.98	124.97
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.23	104.47
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	77.95	103.94

Table 32 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13D					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T10 (Victoria Cross - Dover)	204	204	226.54	111.05
CABLE 3 (Cape Tormrntine - Borden-Carleton)	L1 (New Landing Point - Dover)	204	204	236.27	115.82
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T2 (Crossroad - Charlottetown)	80	80	100.16	125.2
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	52.23	104.45
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	77.94	103.92
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T10 (Victoria Cross - Dover)	204	204	226.91	111.23
CABLE 4 (Cape Tormrntine - Borden-Carleton)	L1 (New Landing Point - Dover)	204	204	236.64	116
T3 (Westroy 138/69 kV Transformer T3)	T2 (Crossroad - Charlottetown)	80	80	92.9	116.13
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	78.63	104.84
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	50	78.63	104.84
T3 (Westroy 138/69 kV Transformer T3)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	53.32	106.63
T3 (Westroy 138/69 kV Transformer T3)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	79.57	106.09
T3 (Westroy 138/69 kV Transformer T3)	T10 (Victoria Cross - Dover)	204	204	205.72	100.84
T3 (Westroy 138/69 kV Transformer T3)	L1 (New Landing Point - Dover)	204	204	215.23	105.5

Table 32 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13D					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Westroy 138/69 kV Transformer T2)	T2 (Crossroad - Charlottetown)	80	80	96.47	120.59
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	91.82	122.43
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	61.52	123.05
T2 (Westroy 138/69 kV Transformer T2)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	53.32	106.63
T2 (Westroy 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	79.57	106.09
T2 (Westroy 138/69 kV Transformer T2)	T10 (Victoria Cross - Dover)	204	204	207.18	101.56
T2 (Westroy 138/69 kV Transformer T2)	L1 (New Landing Point - Dover)	204	204	216.71	106.23
T1 (Westroy 138/69 kV Transformer T1)	T2 (Crossroad - Charlottetown)	80	80	96.47	120.59
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	61.52	123.05
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	91.82	122.43
T1 (Westroy 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	53.32	106.63
T1 (Westroy 138/69 kV Transformer T1)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	79.57	106.09
T1 (Westroy 138/69 kV Transformer T1)	T10 (Victoria Cross - Dover)	204	204	207.18	101.56
T1 (Westroy 138/69 kV Transformer T1)	L1 (New Landing Point - Dover)	204	204	216.71	106.23
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Crossroad - Charlottetown)	80	80	88.14	110.18

Table 32 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13D					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	119.56	239.13
T1 (Sherbrooke 138/69 kV Transformer T1)	L1 (New Landing Point - Dover)	204	204	212.72	104.27
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Crossroad - Charlottetown)	80	80	88.22	110.27
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	126.31	168.41
T2 (Sherbrooke 138/69 kV Transformer T2)	L1 (New Landing Point - Dover)	204	204	212.99	104.41
T2 (Crossroad - Charlottetown)	T1 (Westroy 138/69 kV Transformer T1)	75	75	84.94	113.25
T2 (Crossroad - Charlottetown)	T3 (Westroy 138/69 kV Transformer T3)	50	50	56.91	113.83
T2 (Crossroad - Charlottetown)	T2 (Westroy 138/69 kV Transformer T2)	75	50	84.94	113.25
T2 (Crossroad - Charlottetown)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	53.02	106.04
T2 (Crossroad - Charlottetown)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	79.13	105.5
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	100.43	133.91
T13 (Charlottetown North - UPEI)	T2 (Crossroad - Charlottetown)	80	80	88.34	110.43
T13 (Charlottetown North - UPEI)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	53.24	106.48
T13 (Charlottetown North - UPEI)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	79.46	105.94

Table 32 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13D					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T13 (Charlottetown North - UPEI)	L1 (New Landing Point - Dover)	204	204	212.91	104.37
T15 (Charlottetown North - T15 Tap)	T2 (Crossroad - Charlottetown)	80	80	88.63	110.79
T15 (Charlottetown North - T15 Tap)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	53.28	106.56
T15 (Charlottetown North - T15 Tap)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	79.51	106.02
T15 (Charlottetown North - T15 Tap)	L1 (New Landing Point - Dover)	204	204	213.27	104.54
T15 (T15 Tap - West Royalty)	T2 (Crossroad - Charlottetown)	80	80	90.37	112.97
T15 (T15 Tap - West Royalty)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	53.31	106.62
T15 (T15 Tap - West Royalty)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	79.56	106.08
T15 (T15 Tap - West Royalty)	T10 (Victoria Cross - Dover)	204	204	204.67	100.33
T15 (T15 Tap - West Royalty)	L1 (New Landing Point - Dover)	204	204	214.16	104.98
Y102/Y104 (West Royalty - Marshfield)	T2 (Crossroad - Charlottetown)	80	80	93.26	116.57
Y102/Y104 (West Royalty - Marshfield)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	53.18	106.37
Y102/Y104 (West Royalty - Marshfield)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	79.37	105.83
Y102/Y104 (West Royalty - Marshfield)	L1 (New Landing Point - Dover)	204	204	210.56	103.21

E.1.5 SCENARIO 13E

Table 33 shows the thermal criteria violations identified in Scenario 13E.

Table 33 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13E					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.37	125.82
System Normal	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.23	126.46
System Normal	T13 (West Royalty Tap - UPEI)	80	80	82.66	103.32
System Normal	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.37	125.82
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	122.61	163.48
T3 (Westroy 138/69 kV Transformer T3)	T13 (West Royalty Tap - UPEI)	80	80	81.74	102.18
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	50	122.61	163.48
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	143.83	191.77
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96.37	192.74
T2 (Westroy 138/69 kV Transformer T2)	T13 (West Royalty Tap - UPEI)	80	80	81.44	101.8
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96.37	192.74
T1 (Westroy 138/69 kV Transformer T1)	T13 (West Royalty Tap - UPEI)	80	80	81.44	101.8
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	143.83	191.77

Table 33 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13E					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.23	125.64
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.14	126.28
T1 (Sherbrooke 138/69 kV Transformer T1)	T13 (West Royalty Tap - UPEI)	80	80	85.47	106.83
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.23	125.64
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	106	211.99
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Woodstock Transformer T1)	75	75	80.5	107.33
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.31	125.74
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.19	126.38
T2 (Sherbrooke 138/69 kV Transformer T2)	T13 (West Royalty Tap - UPEI)	80	80	83.82	104.77
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.31	125.74
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	111.05	148.07
T2 (Crossroad - Charlottetown)	T1 (Westroy 138/69 kV Transformer T1)	75	75	84.04	112.05

Table 33 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13E					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Crossroad - Charlottetown)	T3 (Westroy 138/69 kV Transformer T3)	50	50	56.31	112.62
T2 (Crossroad - Charlottetown)	T2 (Westroy 138/69 kV Transformer T2)	75	50	84.04	112.05
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	88.58	118.11
T13 (Charlottetown North - UPEI)	T15 (Charlottetown - T15 Tap)	80	80	108.85	136.06
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	90.36	120.48
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	60.55	121.09
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	121.63	152.04
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	50	90.36	120.48
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	113.87	142.33
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.63	123.5
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.06	124.13
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	125.5	156.88
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	50	92.63	123.5
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	126.51	158.14
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.3	123.07
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	61.85	123.7

Table 33 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 13E					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	139.74	174.67
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	50	92.3	123.07
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	97.52	130.02
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.34	130.69
Y102/Y104 (West Royalty - Marshfield)	T13 (West Royalty Tap - UPEI)	80	80	88.68	110.84
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	50	97.52	130.02

E.1.6 SCENARIO 18A

Table 34 shows the thermal criteria violations identified in Scenario 18A.

Table 34 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18A					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	95.18	126.9
System Normal	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.77	127.55
System Normal	T2 (Westroy 138/69 kV Transformer T2)	75	50	95.18	126.9
System Normal	Cable 3 (Cape Tormentine - Borden)	204	204	217.03	106.39

Table 34 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18A					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	Cable 4 (Cape Tormentine - Borden)	204	204	219.48	107.59
CABLE 1 (Murray Corner - Richcove/Fernwood)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.57	126.09
CABLE 1 (Murray Corner - Richcove/Fernwood)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.37	126.73
CABLE 1 (Murray Corner - Richcove/Fernwood)	T13 (West Royalty Tap - UPEI)	80	80	81.07	101.34
CABLE 1 (Murray Corner - Richcove/Fernwood)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.57	126.09
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 2 (Murray Corner - Richcove/Fernwood)	204	111	226.42	110.99
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 3 (Cape Tormentine - Borden)	204	204	229.26	112.38
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 4 (Cape Tormentine - Borden)	204	204	231.84	113.65
CABLE 2 (Murray Corner - Richcove/Fernwood)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.57	126.09
CABLE 2 (Murray Corner - Richcove/Fernwood)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.37	126.74

Table 34 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18A					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 2 (Murray Corner - Richcove/Fernwood)	T13 (West Royalty Tap - UPEI)	80	80	81.03	101.29
CABLE 2 (Murray Corner - Richcove/Fernwood)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.57	126.09
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	111	227.01	111.28
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 3 (Cape Tormentine - Borden)	204	204	228.91	112.21
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 4 (Cape Tormentine - Borden)	204	204	231.48	113.47
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	123.57	164.76
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	50	123.57	164.76
T3 (Westroy 138/69 kV Transformer T3)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	80.63	107.5
T3 (Westroy 138/69 kV Transformer T3)	Cable 3 (Cape Tormentine - Borden)	204	204	216.77	106.26
T3 (Westroy 138/69 kV Transformer T3)	Cable 4 (Cape Tormentine - Borden)	204	204	219.21	107.46

Table 34 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18A					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	144.85	193.13
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	97.06	194.12
T2 (Westroy 138/69 kV Transformer T2)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	85.02	113.36
T2 (Westroy 138/69 kV Transformer T2)	Cable 3 (Cape Tormentine - Borden)	204	204	216.63	106.19
T2 (Westroy 138/69 kV Transformer T2)	Cable 4 (Cape Tormentine - Borden)	204	204	219.07	107.39
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	97.06	194.12
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	144.85	193.13
T1 (Westroy 138/69 kV Transformer T1)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	85.02	113.36
T1 (Westroy 138/69 kV Transformer T1)	Cable 3 (Cape Tormentine - Borden)	204	204	216.63	106.19
T1 (Westroy 138/69 kV Transformer T1)	Cable 4 (Cape Tormentine - Borden)	204	204	219.07	107.39
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.99	126.65
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.65	127.3

Table 34 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18A					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.99	126.65
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	110.53	221.07
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 3 (Cape Tormentine - Borden)	204	204	215.8	105.78
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 4 (Cape Tormentine - Borden)	204	204	218.23	106.97
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	95.08	126.77
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.71	127.41
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	50	95.08	126.77
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	117.66	156.88
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 3 (Cape Tormentine - Borden)	204	204	216.39	106.07
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 4 (Cape Tormentine - Borden)	204	204	218.83	107.27
T2 (Crossroad - Charlottetown)	T1 (Westroy 138/69 kV Transformer T1)	75	75	82.85	110.46
T2 (Crossroad - Charlottetown)	T3 (Westroy 138/69 kV Transformer T3)	50	50	55.51	111.03

Table 34 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18A					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Crossroad - Charlottetown)	T2 (Westroy 138/69 kV Transformer T2)	75	50	82.85	110.46
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	113.68	151.58
T2 (Crossroad - Charlottetown)	Cable 3 (Cape Tormentine - Borden)	204	204	218.43	107.07
T2 (Crossroad - Charlottetown)	Cable 4 (Cape Tormentine - Borden)	204	204	220.89	108.28
T13 (Charlottetown North - UPEI)	T15 (Charlottetown - T15 Tap)	80	80	92.05	115.07
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.21	122.95
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	61.79	123.57
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	108.36	135.45
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	50	92.21	122.95
T13 (Charlottetown North - UPEI)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	82.21	109.61
T13 (Charlottetown North - UPEI)	Cable 3 (Cape Tormentine - Borden)	204	204	217.01	106.38
T13 (Charlottetown North - UPEI)	Cable 4 (Cape Tormentine - Borden)	204	204	219.45	107.57
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	96.48	120.6
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.79	125.05
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.84	125.69
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	112.36	140.45

Table 34 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18A					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.79	125.05
T15 (Charlottetown North - T15 Tap)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	78.16	104.21
T15 (Charlottetown North - T15 Tap)	Cable 3 (Cape Tormentine - Borden)	204	204	217.08	106.41
T15 (Charlottetown North - T15 Tap)	Cable 4 (Cape Tormentine - Borden)	204	204	219.52	107.61
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	111.95	139.94
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.39	124.52
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.58	125.15
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	128.88	161.1
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.39	124.52
T15 (T15 Tap - West Royalty)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	79.56	106.09
T15 (T15 Tap - West Royalty)	Cable 3 (Cape Tormentine - Borden)	204	204	217.32	106.53
T15 (T15 Tap - West Royalty)	Cable 4 (Cape Tormentine - Borden)	204	204	219.77	107.73
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	98.33	131.11
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.89	131.77
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	50	98.33	131.11

Table 34 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18A					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
Y102/Y104 (West Royalty - Marshfield)	Cable 3 (Cape Tormentine - Borden)	204	204	216.92	106.33
Y102/Y104 (West Royalty - Marshfield)	Cable 4 (Cape Tormentine - Borden)	204	204	219.36	107.53

E.1.7 SCENARIO 18B

Table 35 shows the thermal criteria violations identified in Scenario 18B.

Table 35 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18B					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.54	126.05
System Normal	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.35	126.7
System Normal	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.54	126.05
CABLE 1 (Murray Corner - Richcove/Fernwood)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.74	124.98
CABLE 1 (Murray Corner - Richcove/Fernwood)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.81	125.62
CABLE 1 (Murray Corner - Richcove/Fernwood)	T13 (West Royalty Tap - UPEI)	80	80	82.9	103.62
CABLE 1 (Murray Corner - Richcove/Fernwood)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.74	124.98
CABLE 1 (Murray Corner -	Cable 2 (Murray Corner - Richcove/Fernwood)	204	204	228.71	112.11

Table 35 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18B					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
Richcove/Fernwood)					
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 3 (Cape Tormentine - Borden)	204	204	227.86	111.7
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 4 (Cape Tormentine - Borden)	204	204	230.42	112.95
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.56	124.74
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.69	125.38
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T13 (West Royalty Tap - UPEI)	80	80	82.59	103.24
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.56	124.74
CABLE 3 (Cape Tormrntine - Borden-Carleton)	Cable 2 (Murray Corner - Richcove/Fernwood)	204	204	222.94	109.29
CABLE 3 (Cape Tormrntine - Borden-Carleton)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	111	220.02	107.85
CABLE 3 (Cape Tormrntine - Borden-Carleton)	Cable 4 (Cape Tormentine - Borden)	204	204	246.27	120.72
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.54	124.72
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.68	125.36
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T13 (West Royalty Tap - UPEI)	80	80	82.81	103.51
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.54	124.72
CABLE 4 (Cape Tormrntine - Borden-Carleton)	Cable 2 (Murray Corner - Richcove/Fernwood)	204	204	223.97	109.79

Table 35 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18B					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 4 (Cape Tormrntine - Borden-Carleton)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	111	221.04	108.35
CABLE 4 (Cape Tormrntine - Borden-Carleton)	Cable 3 (Cape Tormentine - Borden)	204	204	244.83	120.01
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	122.86	163.81
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	50	122.86	163.81
T3 (Westroy 138/69 kV Transformer T3)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	78.66	104.87
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	144.21	192.27
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96.63	193.25
T2 (Westroy 138/69 kV Transformer T2)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	83.09	110.79
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96.63	193.25
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	144.21	192.27
T1 (Westroy 138/69 kV Transformer T1)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	83.09	110.79
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.35	125.8
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.22	126.44
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.35	125.8
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	107.71	215.43
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.44	125.92

Table 35 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18B					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.28	126.56
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.44	125.92
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	114.52	152.69
T2 (Crossroad - Charlottetown)	T1 (Westroy 138/69 kV Transformer T1)	75	75	82.29	109.72
T2 (Crossroad - Charlottetown)	T3 (Westroy 138/69 kV Transformer T3)	50	50	55.14	110.27
T2 (Crossroad - Charlottetown)	T2 (Westroy 138/69 kV Transformer T2)	75	50	82.29	109.72
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	109.56	146.08
T13 (Charlottetown North - UPEI)	T15 (Charlottetown - T15 Tap)	80	80	90.17	112.72
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	91.86	122.48
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	61.55	123.1
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	106.56	133.2
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	50	91.86	122.48
T13 (Charlottetown North - UPEI)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	80.14	106.86
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	94.56	118.2
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.31	124.42
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.52	125.05
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	110.32	137.89
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.31	124.42
T15 (Charlottetown North - T15 Tap)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	76.12	101.49
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	110.03	137.53
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.87	123.83
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.23	124.46

Table 35 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18B					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	126.74	158.42
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	50	92.87	123.83
T15 (T15 Tap - West Royalty)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	77.55	103.39
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	97.76	130.35
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.51	131.02
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	50	97.76	130.35

E.1.8 SCENARIO 18C

Table 36 shows the thermal criteria violations identified in Scenario 18C.

Table 36 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18C					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.87	126.49
System Normal	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.57	127.13
System Normal	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.87	126.49
System Normal	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.8	101.6
System Normal	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.79	101.06

Table 36 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18C					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.27	125.69
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.17	126.33
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.27	125.69
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.06	100.11
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.27	125.69
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.16	126.33
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.27	125.69
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.05	100.1
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	123.37	164.49
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	50	123.37	164.49
T3 (Westroy 138/69 kV Transformer T3)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.68	101.36
T3 (Westroy 138/69 kV Transformer T3)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.61	100.82

Table 36 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18C					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T3 (Westroy 138/69 kV Transformer T3)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	76	101.34
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	144.84	193.12
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	97.05	194.1
T2 (Westroy 138/69 kV Transformer T2)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.59	101.17
T2 (Westroy 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.48	100.64
T2 (Westroy 138/69 kV Transformer T2)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	80.5	107.33
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	97.05	194.1
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	144.84	193.12
T1 (Westroy 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.59	101.17
T1 (Westroy 138/69 kV Transformer T1)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.48	100.64
T1 (Westroy 138/69 kV Transformer T1)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	80.5	107.33
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.63	126.17

Table 36 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18C					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.41	126.81
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.63	126.17
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	113.04	226.08
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.72	126.29
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.47	126.94
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.72	126.29
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	119.96	159.94
T2 (Crossroad - Charlottetown)	T1 (Westroy 138/69 kV Transformer T1)	75	75	82.6	110.13
T2 (Crossroad - Charlottetown)	T3 (Westroy 138/69 kV Transformer T3)	50	50	55.35	110.69
T2 (Crossroad - Charlottetown)	T2 (Westroy 138/69 kV Transformer T2)	75	50	82.6	110.13
T2 (Crossroad - Charlottetown)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.71	101.42
T2 (Crossroad - Charlottetown)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.66	100.88
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	103.42	137.89
T13 (Charlottetown North - UPEI)	T15 (Charlottetown - T15 Tap)	80	80	89.86	112.32

Table 36 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18C					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.28	123.03
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	61.83	123.66
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	106.72	133.41
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	50	92.28	123.03
T13 (Charlottetown North - UPEI)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.68	101.36
T13 (Charlottetown North - UPEI)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.62	100.82
T13 (Charlottetown North - UPEI)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	77.3	103.06
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	94.12	117.65
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.7	124.93
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.78	125.56
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	110.55	138.19
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.7	124.93
T15 (Charlottetown North - T15 Tap)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.75	101.5
T15 (Charlottetown North - T15 Tap)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.72	100.96
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	110.04	137.54
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.25	124.34

Table 36 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18C					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.49	124.97
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	127.39	159.24
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.25	124.34
T15 (T15 Tap - West Royalty)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.74	101.48
T15 (T15 Tap - West Royalty)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.71	100.94
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	97.79	130.39
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.53	131.05
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	50	97.79	130.39
Y102/Y104 (West Royalty - Marshfield)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.85	101.69
Y102/Y104 (West Royalty - Marshfield)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.86	101.15

E.1.9 SCENARIO 18D

Table 37 shows the thermal criteria violations identified in Scenario 18D.

Table 37 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18D					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.94	101.87
System Normal	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	76	101.33
System Normal	L1 (New Landing Point - Dover)	204	204	212.03	103.93
CABLE 1 (Murray Corner - Richcove/Fernwood)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.14	100.29
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	135.46	122.04
CABLE 1 (Murray Corner - Richcove/Fernwood)	T10 (Victoria Cross - Dover)	204	204	206.24	101.1
CABLE 1 (Murray Corner - Richcove/Fernwood)	L1 (New Landing Point - Dover)	204	204	215.85	105.81
CABLE 2 (Murray Corner - Richcove/Fernwood)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.14	100.29
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	135.46	122.04
CABLE 2 (Murray Corner - Richcove/Fernwood)	T10 (Victoria Cross - Dover)	204	204	206.24	101.1

Table 37 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18D					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 2 (Murray Corner - Richcove/Fernwood)	L1 (New Landing Point - Dover)	204	204	215.85	105.81
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.01	100.03
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T10 (Victoria Cross - Dover)	204	204	226.61	111.08
CABLE 3 (Cape Tormrntine - Borden-Carleton)	L1 (New Landing Point - Dover)	204	204	236.26	115.82
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.01	100.01
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T10 (Victoria Cross - Dover)	204	204	226.98	111.27
CABLE 4 (Cape Tormrntine - Borden-Carleton)	L1 (New Landing Point - Dover)	204	204	236.64	116
T3 (Westroy 138/69 kV Transformer T3)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.95	101.89
T3 (Westroy 138/69 kV Transformer T3)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	76.01	101.35
T3 (Westroy 138/69 kV Transformer T3)	T10 (Victoria Cross - Dover)	204	204	204.64	100.31
T3 (Westroy 138/69 kV Transformer T3)	L1 (New Landing Point - Dover)	204	204	214.18	104.99

Table 37 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18D					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	86.55	115.4
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	58	115.99
T2 (Westroy 138/69 kV Transformer T2)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.94	101.88
T2 (Westroy 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	76	101.34
T2 (Westroy 138/69 kV Transformer T2)	T10 (Victoria Cross - Dover)	204	204	206.25	101.1
T2 (Westroy 138/69 kV Transformer T2)	L1 (New Landing Point - Dover)	204	204	215.8	105.79
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	58	115.99
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	86.55	115.4
T1 (Westroy 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.94	101.88
T1 (Westroy 138/69 kV Transformer T1)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	76	101.34
T1 (Westroy 138/69 kV Transformer T1)	T10 (Victoria Cross - Dover)	204	204	206.25	101.1
T1 (Westroy 138/69 kV Transformer T1)	L1 (New Landing Point - Dover)	204	204	215.8	105.79

Table 37 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18D					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	113.13	226.27
T1 (Sherbrooke 138/69 kV Transformer T1)	L1 (New Landing Point - Dover)	204	204	211.88	103.86
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	120.17	160.23
T2 (Sherbrooke 138/69 kV Transformer T2)	L1 (New Landing Point - Dover)	204	204	211.96	103.9
T2 (Crossroad - Charlottetown)	T1 (Westroy 138/69 kV Transformer T1)	75	75	81.38	108.51
T2 (Crossroad - Charlottetown)	T3 (Westroy 138/69 kV Transformer T3)	50	50	54.53	109.06
T2 (Crossroad - Charlottetown)	T2 (Westroy 138/69 kV Transformer T2)	75	50	81.38	108.51
T2 (Crossroad - Charlottetown)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.59	101.17
T2 (Crossroad - Charlottetown)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.48	100.63
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	93.64	124.85
T13 (Charlottetown North - UPEI)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.88	101.75
T13 (Charlottetown North - UPEI)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.91	101.21
T13 (Charlottetown North - UPEI)	L1 (New Landing Point - Dover)	204	204	211.57	103.71
T15 (Charlottetown North - T15 Tap)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.92	101.83
T15 (Charlottetown North - T15 Tap)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.97	101.29

Table 37 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18D					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (Charlottetown North - T15 Tap)	L1 (New Landing Point - Dover)	204	204	212.01	103.93
T15 (T15 Tap - West Royalty)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.95	101.9
T15 (T15 Tap - West Royalty)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	76.02	101.36
T15 (T15 Tap - West Royalty)	L1 (New Landing Point - Dover)	204	204	212.93	104.38
Y102/Y104 (West Royalty - Marshfield)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.93	101.86
Y102/Y104 (West Royalty - Marshfield)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	75.99	101.32
Y102/Y104 (West Royalty - Marshfield)	L1 (New Landing Point - Dover)	204	204	209.03	102.47

E.1.10 SCENARIO 18E

Table 38 shows the thermal criteria violations identified in Scenario 18E.

Table 38 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18E					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.22	125.63
System Normal	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.13	126.27
System Normal	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.22	125.63

Table 38 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18E					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 1 (Murray Corner - Richcove/Fernwood)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.52	124.7
CABLE 1 (Murray Corner - Richcove/Fernwood)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.67	125.33
CABLE 1 (Murray Corner - Richcove/Fernwood)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.52	124.7
CABLE 1 (Murray Corner - Richcove/Fernwood)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	183.03	164.89
CABLE 2 (Murray Corner - Richcove/Fernwood)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.52	124.7
CABLE 2 (Murray Corner - Richcove/Fernwood)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.67	125.33
CABLE 2 (Murray Corner - Richcove/Fernwood)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.52	124.7
CABLE 2 (Murray Corner - Richcove/Fernwood)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	183.03	164.89
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.96	123.95

Table 38 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18E					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.29	124.58
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T2 (Westroy 138/69 kV Transformer T2)	75	50	92.96	123.95
CABLE 3 (Cape Tormrntine - Borden-Carleton)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	142.11	128.03
CABLE 3 (Cape Tormrntine - Borden-Carleton)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	142.11	128.03
CABLE 3 (Cape Tormrntine - Borden-Carleton)	Cable 4 (Cape Tormentine - Borden)	204	204	264.19	129.5
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.93	123.91
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.27	124.54
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T13 (West Royalty Tap - UPEI)	80	80	80.26	100.33
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T2 (Westroy 138/69 kV Transformer T2)	75	50	92.93	123.91
CABLE 4 (Cape Tormrntine - Borden-Carleton)	Cable 2 (Murray Corner - Richcove/Fernwood)	111	111	142.82	128.66
CABLE 4 (Cape Tormrntine - Borden-Carleton)	Cable 1 (Murray Corner - Richcove/Fernwood)	111	111	142.82	128.66
CABLE 4 (Cape Tormrntine - Borden-Carleton)	Cable 3 (Cape Tormentine - Borden)	204	204	262.76	128.8

Table 38 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18E					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	122.61	163.47
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	50	122.61	163.47
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	144.01	192.02
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96.5	193
T2 (Westroy 138/69 kV Transformer T2)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	79.06	105.42
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	96.5	193
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	144.01	192.02
T1 (Westroy 138/69 kV Transformer T1)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	79.06	105.42
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.08	125.44
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.04	126.08
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.08	125.44
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	99.67	199.35

Table 38 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18E					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Woodstock Transformer T1)	75	75	80.58	107.44
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.15	125.54
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.09	126.18
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	50	94.15	125.54
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	50	105.48	140.65
T2 (Crossroad - Charlottetown)	T1 (Westroy 138/69 kV Transformer T1)	75	75	81.78	109.04
T2 (Crossroad - Charlottetown)	T3 (Westroy 138/69 kV Transformer T3)	50	50	54.8	109.59
T2 (Crossroad - Charlottetown)	T2 (Westroy 138/69 kV Transformer T2)	75	50	81.78	109.04
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	102.35	136.46
T13 (Charlottetown North - UPEI)	T15 (Charlottetown - T15 Tap)	80	80	86.86	108.57
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	91.75	122.33
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	61.48	122.95
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	103.81	129.76
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	50	91.75	122.33

Table 38 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Scenario 18E					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T13 (Charlottetown North - UPEI)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	75.72	100.96
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	90.9	113.63
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.1	124.13
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.38	124.76
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	107.68	134.6
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	50	93.1	124.13
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	106.85	133.56
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.65	123.53
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.08	124.16
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	124.41	155.51
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	50	92.65	123.53
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	97.64	130.19
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.42	130.85
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	50	97.64	130.19

Appendix F Reactive Power Support Devices for PEI Proposed Intertie System

Table 39 shows the reactive power devices added in the study scenarios for the PEI proposed intertie system.

Table 39 Reactive Power Devices

Scenario #	Location where Reactive Power Device Added	Reactive Power Device Size (MVAR)	Area
12A	Borden	20	Central
12B	Borden	20	Central
13A	West Royalty	20	City
	Clyde River Tap	20	Central
	Borden	80	Central
	Bedeque	45	Central
	Sherbrooke	40	West
	Sherbrooke	30	West
	Wellington	10	West
	Alberton	50	West
	Charlottetown	20	City
	Cross Roads	20	East
	Dingwell Mills	20	East
	Victoria Cross	20	East
13B	West Royalty	20	City
	Clyde River Tap	20	Central
	Borden	90	Central
	Bedeque	45	Central
	Sherbrooke	10	West
	Alberton	10	West
	Cross Roads	30	City
	Dingwell Mills	40	East
	Victoria Cross	20	East
	Dingwell Mills	15	East
	Victoria Cross	20	East
13C	West Royalty	20	City
	Clyde River Tap	25	Central

Table 39 Reactive Power Devices			
	Borden	40	Central
	Bedeque	30	Central
	Sherbrooke	20	West
	Alberton	10	West
	Charlottetown	20	City
	Cross Roads	20	East
	Dingwell Mills	10	East
	Victoria Cross	20	East
13D	West Royalty	10	City
	Borden	5	Central
	Bedeque	45	Central
	Sherbrooke	20	West
	Alberton	5	West
	Charlottetown	50	City
	Dingwell Mills	5	East
	Victoria Cross	30	East
13E	West Royalty	10	City
	Borden	40	Central
	Bedeque	45	Central
	Sherbrooke	20	West
	Alberton	15	West
	Charlottetown	50	City
	Cross Roads	20	East
	Dingwell Mills	20	East
	Victoria Cross	20	East
18A	West Royalty	50	City
	Borden	20	Central
	Church Road	10	East
	Clyde River Tap	30	Central
	Borden	50	Central
	Bedeque	40	Central
	Sherbrooke	30	West
	Alberton	20	West
	West Royalty	20	City
	Charlottetown	30	City
	Cross Roads	30	East
	Dingwell Mills	15	East
	Victoria Cross	30	East
18B	West Royalty	50	City

Table 39 Reactive Power Devices			
	Borden	20	Central
	Church Road	10	East
	Clyde River Tap	30	Central
	Borden	50	Central
	Bedeque	40	Central
	Sherbrooke	30	West
	Alberton	20	West
	West Royalty	20	City
	Charlottetown	30	City
	Cross Roads	30	East
	Dingwell Mills	15	East
	Victoria Cross	25	East
18C	West Royalty	50	City
	Borden	20	Central
	Church Road	10	East
	Clyde River Tap	30	Central
	Borden	30	Central
	Bedeque	15	Central
	Sherbrooke	20	West
	Alberton	10	West
	West Royalty	20	City
	Charlottetown	30	City
	Cross Roads	30	East
	Dingwell Mills	10	East
	Victoria Cross	15	East
18D	West Royalty	50	City
	Borden	20	Central
	Church Road	10	East
	Clyde River Tap	10	Central
	Borden	20	Central
	Alberton	10	West
	West Royalty	10	City
	Charlottetown	30	City
	Cross Roads	30	East
	Dingwell Mills	10	East
	Victoria Cross	10	East
18E	West Royalty	50	City
	Borden	20	Central
	Church Road	10	East

Table 39 Reactive Power Devices			
	Clyde River Tap	30	Central
	Borden	60	Central
	Bedeque	20	Central
	Sherbrooke	30	West
	Alberton	10	West
	West Royalty	20	City
	Charlottetown	30	City
	Cross Roads	30	East
	Dingwell Mills	10	East
	Victoria Cross	10	East
13B (800 MW)	West Royalty	50	City
	Borden (SVC)	204.96	Central
	Church Road	30	East
	Clyde River Tap	20	Central
	Borden (SVC)	204.96	Central
	Bedeque	45	Central
	Sherbrooke	40	West
	Sherbrooke (SVC)	48.1	West
	Wellington	10	West
	Alberton	45	West
	Rattenbury	10	Central
	West Royalty	60	City
	Charlottetown	40	City
	Cross Roads	20	East
	Marshfield	20	City
	Dingwell Mills	30	East
	Victoria Cross	40	East
13D (800 MW)	West Royalty	60	City
	Borden (SVC)	111.09	Central
	Bedeque	70	Central
	Sherbrooke	50	West
	Sherbrooke (SVC)	35.14	West
	Alberton	35	West
	West Royalty	10	City
	Charlottetown	60	City
	Cross Roads	20	East
	Marshfield	20	City
	Dingwell Mills	40	East
	Victoria Cross	40	East

Appendix G Power Flow Results for PEI Intertie Options Under Review

G.1 Power Flow Results

The tables below present the power flow results for PEI investigated intertie scenarios.

G.1.1 ADDITIONAL SCENARIO 1

Table 40 shows the thermal criteria violations identified in Additional Scenario 1.

Table 40 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 1

Contingency (System Element Lost)	Violation Location Details	Thermal Ratings (MVA)		Results	
		Normal Rating	Emergency Rating	Power Flow (MVA)	% Loading
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.11	125.48
System Normal	T3 (Westroy 138/69 kV Transformer T3)	50	50	63.06	126.12
System Normal	T2 (Westroy 138/69 kV Transformer T2)	75	75	94.11	125.48
System Normal	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	51.16	102.32
System Normal	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	76.36	101.81
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	122.15	162.87
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	75	122.15	162.87
T3 (Westroy 138/69 kV Transformer T3)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.92	101.83
T3 (Westroy 138/69 kV Transformer T3)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	75.99	101.32

Table 40 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 1					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	143.19	190.92
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	95.94	191.89
T2 (Westroy 138/69 kV Transformer T2)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.71	101.42
T2 (Westroy 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	75.68	100.91
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	95.94	191.89
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	75	143.19	190.92
T1 (Westroy 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.71	101.42
T1 (Westroy 138/69 kV Transformer T1)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	75.68	100.91
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.76	125.01
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.82	125.64
T1 (Sherbrooke 138/69 kV Transformer T1)	T13 (West Royalty Tap - UPEI)	80	80	83.9	104.88
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	75	93.76	125.01

Table 40 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 1					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	114.43	228.87
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	93.92	125.23
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62.93	125.87
T2 (Sherbrooke 138/69 kV Transformer T2)	T13 (West Royalty Tap - UPEI)	80	80	81.6	101.99
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	75	93.92	125.23
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	120.83	161.1
T2 (Crossroad - Charlottetown)	T1 (Westroy 138/69 kV Transformer T1)	75	75	83.43	111.24
T2 (Crossroad - Charlottetown)	T3 (Westroy 138/69 kV Transformer T3)	50	50	55.9	111.8
T2 (Crossroad - Charlottetown)	T2 (Westroy 138/69 kV Transformer T2)	75	75	83.43	111.24
T2 (Crossroad - Charlottetown)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.82	101.64
T2 (Crossroad - Charlottetown)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	75.84	101.12
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	85.18	113.57
T13 (Charlottetown North - UPEI)	T15 (Charlottetown North - T15 Tap)	80	80	103.84	129.79
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	90.63	120.85

Table 40 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 1					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	60.73	121.46
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	117.72	147.14
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	75	90.63	120.85
T13 (Charlottetown North - UPEI)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.78	101.55
T13 (Charlottetown North - UPEI)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	75.78	101.04
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	107.58	134.47
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.53	123.37
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	62	124
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	120.54	150.68
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	75	92.53	123.37
T15 (Charlottetown North - T15 Tap)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	51	102
T15 (Charlottetown North - T15 Tap)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	76.11	101.49
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	121.3	151.63
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	92.17	122.89
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	61.76	123.52
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	135.68	169.6
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	75	92.17	122.89

Table 40 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 1					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (T15 Tap - West Royalty)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	50.98	101.95
T15 (T15 Tap - West Royalty)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	76.08	101.43
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	97.06	129.41
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	65.03	130.07
Y102/Y104 (West Royalty - Marshfield)	T13 (West Royalty Tap - UPEI)	80	80	84.46	105.57
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	75	97.06	129.41
Y102/Y104 (West Royalty - Marshfield)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	51.13	102.26
Y102/Y104 (West Royalty - Marshfield)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	76.31	101.74

G.1.2 ADDITIONAL SCENARIO 3

Table 41 shows the thermal criteria violations identified in Additional Scenario 3.

Table 41 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 3					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.11	125.48

Table 41 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 3					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	82.42	109.89
System Normal	T3 (Westroy 138/69 kV Transformer T3)	50	50	55.22	110.45
System Normal	T2 (Westroy 138/69 kV Transformer T2)	75	75	82.42	109.89
CABLE 1 (Murray Corner - Richcove/Fernwood)	T1 (Westroy 138/69 kV Transformer T1)	75	75	81.37	108.5
CABLE 1 (Murray Corner - Richcove/Fernwood)	T3 (Westroy 138/69 kV Transformer T3)	50	50	54.53	109.05
CABLE 1 (Murray Corner - Richcove/Fernwood)	T2 (Westroy 138/69 kV Transformer T2)	75	75	81.37	108.5
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T1 (Westroy 138/69 kV Transformer T1)	75	75	81.36	108.47
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T3 (Westroy 138/69 kV Transformer T3)	50	50	54.51	109.03
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T2 (Westroy 138/69 kV Transformer T2)	75	75	81.36	108.47
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T1 (Westroy 138/69 kV Transformer T1)	75	75	81.35	108.46
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T3 (Westroy 138/69 kV Transformer T3)	50	50	54.51	109.02
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T2 (Westroy 138/69 kV Transformer T2)	75	75	81.35	108.46

Table 41 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 3					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	106.96	142.62
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	75	106.96	142.62
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	125.39	167.19
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	84.02	168.04
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	84.02	168.04
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	75	125.39	167.19
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	82.56	110.08
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	55.32	110.64
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	75	82.56	110.08
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	82.51	110.01
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	55.29	110.57
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	75	82.51	110.01

Table 41 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 3					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Crossroad - Charlottetown)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	86.55	115.4
T13 (Charlottetown North - UPEI)	T15 (Charlottetown North - T15 Tap)	80	80	80.69	100.86
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	80.36	107.14
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	53.84	107.69
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	75	80.36	107.14
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	83.69	104.62
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	81.2	108.27
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	54.41	108.82
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	101.49	126.87
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	75	81.2	108.27
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	83.34	104.18
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	81.58	108.78
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	54.67	109.33
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	99.52	124.4
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	75	81.58	108.78
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	80.86	107.81

Table 41 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 3					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	54.18	108.36
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	75	80.86	107.81

G.1.3 ADDITIONAL SCENARIO 4

Table 42 shows the thermal criteria violations identified in Additional Scenario 4.

Table 42 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.11	125.48
System Normal	Y111 (West Royalty - Bedeque)	189	189	225.57	119.35
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	129.74	172.99
System Normal	T3 (Westroy 138/69 kV Transformer T3)	50	50	86.93	173.87
System Normal	T13 (West Royalty Tap - UPEI)	80	80	100.12	125.15
System Normal	T2 (Westroy 138/69 kV Transformer T2)	75	75	129.74	172.99
System Normal	Y109 (Borden - Clyderiver Tap)	189	189	211.13	111.71
System Normal	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	60.50	121.01
System Normal	Cable 2 (Murray Corner - Rchmond Cove)	204	204	256.21	125.6
System Normal	Cable 1 (Murray Corner - Richcove/Fernwood)	204	204	253.77	124.4

Table 42 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	90.3	120.4
System Normal	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	87.34	116.45
System Normal	Cable 3 (Cape Tormentine - Borden Cables)	204	204	275.43	135.02
System Normal	Cable 4 (Cape Tormentine - Borden Cables)	204	204	278.55	136.54
T3 (West Royalty 138/69 kV Transformer T3)	Y111 (West Royalty - Bedeque)	189	189	223.46	118.23
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	168.38	224.51
T3 (West Royalty 138/69 kV Transformer T3)	T13 (West Royalty Tap - UPEI)	80	80	96.49	120.61
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	75	168.38	224.51
T3 (West Royalty 138/69 kV Transformer T3)	Y109 (Borden - Clyderiver Tap)	189	189	210.01	111.12
T3 (West Royalty 138/69 kV Transformer T3)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	60.49	120.98
T3 (West Royalty 138/69 kV Transformer T3)	Cable 2 (Murray Corner - Rchmond Cove)	204	204	254.86	124.93
T3 (West Royalty 138/69 kV Transformer T3)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	204	252.41	123.73
T3 (West Royalty 138/69 kV Transformer T3)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	90.27	120.37

Table 42 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T3 (Westroy 138/69 kV Transformer T3)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	95.07	126.76
T3 (West Royalty 138/69 kV Transformer T3)	Cable 3 (Cape Tormentine - Borden Cables)	204	204	274.43	134.53
T3 (West Royalty 138/69 kV Transformer T3)	Cable 4 (Cape Tormentine - Borden Cables)	204	204	277.54	136.05
T2 (West Royalty 138/69 kV Transformer T2)	Y111 (West Royalty - Bedeque)	189	189	222.15	117.54
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	197.26	263.02
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	132.18	264.36
T2 (West Royalty 138/69 kV Transformer T2)	T13 (West Royalty Tap - UPEI)	80	80	93.95	117.44
T2 (West Royalty 138/69 kV Transformer T2)	Y109 (Borden - Clyderiver Tap)	189	189	209.43	110.81
T2 (West Royalty 138/69 kV Transformer T2)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	60.48	120.96
T2 (West Royalty 138/69 kV Transformer T2)	Cable 2 (Murray Corner - Rchmond Cove)	204	204	254.23	124.62
T2 (West Royalty 138/69 kV Transformer T2)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	204	251.77	123.41
T2 (West Royalty 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	90.26	120.35

Table 42 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Westroy 138/69 kV Transformer T2)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	100.86	134.48
T2 (West Royalty 138/69 kV Transformer T2)	Cable 3 (Cape Tormentine - Borden Cables)	204	204	274.11	134.37
T2 (West Royalty 138/69 kV Transformer T2)	Cable 4 (Cape Tormentine - Borden Cables)	204	204	277.21	135.89
T1 (West Royalty 138/69 kV Transformer T1)	Y111 (West Royalty - Bedeque)	189	189	222.15	117.54
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	132.18	264.36
T1 (West Royalty 138/69 kV Transformer T1)	T13 (West Royalty Tap - UPEI)	80	80	93.95	117.44
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	75	197.26	263.02
T1 (West Royalty 138/69 kV Transformer T1)	Y109 (Borden - Clyderiver Tap)	189	189	209.43	110.81
T1 (West Royalty 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	60.48	120.96
T1 (West Royalty 138/69 kV Transformer T1)	Cable 2 (Murray Corner - Rchmond Cove)	204	204	254.23	124.62
T1 (West Royalty 138/69 kV Transformer T1)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	204	251.77	123.41
T1 (West Royalty 138/69 kV Transformer T1)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	90.26	120.35

Table 42 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Westroy 138/69 kV Transformer T1)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	100.86	134.48
T1 (West Royalty 138/69 kV Transformer T1)	Cable 3 (Cape Tormentine - Borden Cables)	204	204	274.11	134.37
T1 (West Royalty 138/69 kV Transformer T1)	Cable 4 (Cape Tormentine - Borden Cables)	204	204	277.21	135.89
T1 (Sherbrooke 138/69 kV Transformer T1)	Y111 (West Royalty - Bedeque)	189	189	225.65	119.39
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	129.72	172.95
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	86.92	173.83
T1 (Sherbrooke 138/69 kV Transformer T1)	T13 (West Royalty Tap - UPEI)	80	80	100.22	125.27
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	75	129.72	172.95
T1 (Sherbrooke 138/69 kV Transformer T1)	Y109 (Borden - Clyderiver Tap)	189	189	211.18	111.74
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	134.44	268.87
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 2 (Murray Corner - Rchmond Cove)	204	204	257.23	126.09
T1 (Sherbrooke 138/69 kV Transformer T1)	Y103 (Rchmond Cove - Bedeque)	241	241	241.51	100.21

Table 42 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	204	254.79	124.89
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Wstock 138/69 kV Transformer T1)	75	75	87.3	116.4
T1 (Sherbrooke 138/69 kV Transformer T1)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	87.28	116.37
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 3 (Cape Tormentine - Borden Cables)	204	204	276.96	135.76
T1 (Sherbrooke 138/69 kV Transformer T1)	Cable 4 (Cape Tormentine - Borden Cables)	204	204	280.09	137.3
T2 (Sherbrooke 138/69 kV Transformer T2)	Y111 (West Royalty - Bedeque)	189	189	225.6	119.36
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	129.73	172.97
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	86.93	173.85
T2 (Sherbrooke 138/69 kV Transformer T2)	T13 (West Royalty Tap - UPEI)	80	80	100.15	125.19
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	75	129.73	172.97
T2 (Sherbrooke 138/69 kV Transformer T2)	Y109 (Borden - Clyderiver Tap)	189	189	211.15	111.72
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 2 (Murray Corner - Rchmond Cove)	204	204	256.64	125.8

Table 42 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	204	254.2	124.61
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Wstock 138/69 kV Transformer T1)	75	75	78.14	104.19
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	142.83	190.44
T2 (Sherbrooke 138/69 kV Transformer T2)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	87.32	116.43
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 3 (Cape Tormentine - Borden Cables)	204	204	276.04	135.31
T2 (Sherbrooke 138/69 kV Transformer T2)	Cable 4 (Cape Tormentine - Borden Cables)	204	204	279.16	136.84
T13 (Charlottetown North - UPEI)	Y111 (West Royalty - Bedeque)	189	189	223.95	118.49
T13 (Charlottetown North - UPEI)	T15 (Charlottetown North - T15 Tap)	80	80	122.27	152.84
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	125.3	167.06
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	83.96	167.91
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	144.38	180.48
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	75	125.3	167.06
T13 (Charlottetown North - UPEI)	Y109 (Borden - Clyderiver Tap)	189	189	210.33	111.29
T13 (Charlottetown North - UPEI)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	60.49	120.98

Table 42 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T13 (Charlottetown North - UPEI)	Cable 2 (Murray Corner - Rchmond Cove)	204	204	255.95	125.46
T13 (Charlottetown North - UPEI)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	204	253.5	124.26
T13 (Charlottetown North - UPEI)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	90.27	120.36
T13 (Charlottetown North - UPEI)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	97.16	129.55
T13 (Charlottetown North - UPEI)	Cable 3 (Cape Tormentine - Borden Cables)	204	204	275.65	135.12
T13 (Charlottetown North - UPEI)	Cable 4 (Cape Tormentine - Borden Cables)	204	204	278.77	136.65
T15 (Charlottetown North - T15 Tap)	Y111 (West Royalty - Bedeque)	189	189	224.87	118.98
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	128.56	160.7
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	127.78	170.37
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	85.62	171.24
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	149.11	186.38
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	75	127.78	170.37
T15 (Charlottetown North - T15 Tap)	Y109 (Borden - Clyderiver Tap)	189	189	210.79	111.53
T15 (Charlottetown North - T15 Tap)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	60.5	120.99
T15 (Charlottetown North - T15 Tap)	Cable 2 (Murray Corner - Rchmond Cove)	204	204	256.14	125.56
T15 (Charlottetown North - T15 Tap)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	204	253.69	124.36
T15 (Charlottetown North - T15 Tap)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	90.28	120.38

Table 42 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (Charlottetown North - T15 Tap)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	91.77	122.35
T15 (Charlottetown North - T15 Tap)	Cable 3 (Cape Tormentine - Borden Cables)	204	204	275.6	135.1
T15 (Charlottetown North - T15 Tap)	Cable 4 (Cape Tormentine - Borden Cables)	204	204	278.72	136.63
T15 (T15 Tap - West Royalty)	Y111 (West Royalty - Bedeque)	189	189	224.99	119.04
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	149.51	186.88
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	127.3	169.73
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	85.3	170.6
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	171.66	214.57
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	75	127.3	169.73
T15 (T15 Tap - West Royalty)	Y109 (Borden - Clyderiver Tap)	189	189	210.94	111.61
T15 (T15 Tap - West Royalty)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	60.49	120.98
T15 (T15 Tap - West Royalty)	Cable 2 (Murray Corner - Rchmond Cove)	204	204	256.72	125.84
T15 (T15 Tap - West Royalty)	Y103 (Rchmond Cove - Bedeque)	241	241	241.07	100.03
T15 (T15 Tap - West Royalty)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	204	254.28	124.65
T15 (T15 Tap - West Royalty)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	90.28	120.37
T15 (T15 Tap - West Royalty)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	93.39	124.52
T15 (T15 Tap - West Royalty)	Cable 3 (Cape Tormentine - Borden Cables)	204	204	276.43	135.51

Table 42 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (T15 Tap - West Royalty)	Cable 4 (Cape Tormentine - Borden Cables)	204	204	279.56	137.04
Y102/Y104 (West Royalty - Marshfield)	Y111 (West Royalty - Bedeque)	189	189	207.18	109.62
Y102/Y104 (West Royalty - Marshfield)	T13 (Charlottetown North - UPEI)	80	80	87.82	109.78
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	134.05	178.73
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	89.82	179.64
Y102/Y104 (West Royalty - Marshfield)	T13 (West Royalty Tap - UPEI)	80	80	108.18	135.22
Y102/Y104 (West Royalty - Marshfield)	T15 (West Royalty - T15TAP)	80	80	81.51	101.89
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	75	134.05	178.73
Y102/Y104 (West Royalty - Marshfield)	Y109 (Borden - Clyderiver Tap)	189	189	198.01	104.77
Y102/Y104 (West Royalty - Marshfield)	T2 (Sherbrooke 138/69 kV Transformer T2)	50	50	60.49	120.98
Y102/Y104 (West Royalty - Marshfield)	Cable 2 (Murray Corner - Rchmond Cove)	204	204	259.33	127.12
Y102/Y104 (West Royalty - Marshfield)	Y103 (Rchmond Cove - Bedeque)	241	241	243.5	101.04

Table 42 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 4					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
Y102/Y104 (West Royalty - Marshfield)	Cable 1 (Murray Corner - Richcove/Fernwood)	204	204	256.9	125.93
Y102/Y104 (West Royalty - Marshfield)	P3 (Bedeque - Scotchfort)	189	189	191.72	101.44
Y102/Y104 (West Royalty - Marshfield)	T1 (Sherbrooke 138/69 kV Transformer T1)	75	75	90.28	120.37
Y102/Y104 (West Royalty - Marshfield)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	75.87	101.16
Y102/Y104 (West Royalty - Marshfield)	Cable 3 (Cape Tormentine - Borden Cables)	204	204	278.01	136.28
Y102/Y104 (West Royalty - Marshfield)	Cable 4 (Cape Tormentine - Borden Cables)	204	204	281.15	137.82

G.1.4 ADDITIONAL SCENARIO 6

Table 43 shows the thermal criteria violations identified in Additional Scenario 6

Table 43 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 6					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	94.11	125.48
System Normal	T1 (Westroy 138/69 kV Transformer T1)	75	75	117.18	156.24
System Normal	T3 (Westroy 138/69 kV Transformer T3)	50	50	78.52	157.03
System Normal	T13 (West Royalty Tap - UPEI)	80	80	90.34	112.93

Table 43 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 6					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
System Normal	T2 (Westroy 138/69 kV Transformer T2)	75	75	117.18	156.24
System Normal	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	96.17	128.23
CABLE 1 (Murray Corner - Richcove/Fernwood)	T1 (Westroy 138/69 kV Transformer T1)	75	75	117.49	156.65
CABLE 1 (Murray Corner - Richcove/Fernwood)	T3 (Westroy 138/69 kV Transformer T3)	50	50	78.72	157.45
CABLE 1 (Murray Corner - Richcove/Fernwood)	T13 (West Royalty Tap - UPEI)	80	80	90.58	113.22
CABLE 1 (Murray Corner - Richcove/Fernwood)	T2 (Westroy 138/69 kV Transformer T2)	75	75	117.49	156.65
CABLE 1 (Murray Corner - Richcove/Fernwood)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	95.91	127.88
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T1 (Westroy 138/69 kV Transformer T1)	75	75	117.38	156.51
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T3 (Westroy 138/69 kV Transformer T3)	50	50	78.65	157.31
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T13 (West Royalty Tap - UPEI)	80	80	90.4	113
CABLE 3 (Cape Tormrntine - Borden-Carleton)	T2 (Westroy 138/69 kV Transformer T2)	75	75	117.38	156.51

Table 43 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 6					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
CABLE 3 (Cape Tormrntine - Borden-Carleton)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	96.2	128.26
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T1 (Westroy 138/69 kV Transformer T1)	75	75	117.39	156.51
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T3 (Westroy 138/69 kV Transformer T3)	50	50	78.66	157.31
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T13 (West Royalty Tap - UPEI)	80	80	90.4	113
CABLE 4 (Cape Tormrntine - Borden-Carleton)	T2 (Westroy 138/69 kV Transformer T2)	75	75	117.39	156.51
CABLE 4 (Cape Tormrntine - Borden-Carleton)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	96.2	128.26
T3 (Westroy 138/69 kV Transformer T3)	T1 (Westroy 138/69 kV Transformer T1)	75	75	152.77	203.69
T3 (West Royalty 138/69 kV Transformer T3)	T13 (West Royalty Tap - UPEI)	80	80	85.66	107.08
T3 (Westroy 138/69 kV Transformer T3)	T2 (Westroy 138/69 kV Transformer T2)	75	75	152.77	203.69
T3 (Westroy 138/69 kV Transformer T3)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	103.65	138.2
T2 (Westroy 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	179.68	239.58
T2 (Westroy 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	120.4	240.8

Table 43 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 6					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (West Royalty 138/69 kV Transformer T2)	T13 (West Royalty Tap - UPEI)	80	80	82.12	102.65
T2 (Westroy 138/69 kV Transformer T2)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	109.28	145.71
T1 (Westroy 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	120.4	240.8
T1 (West Royalty 138/69 kV Transformer T1)	T13 (West Royalty Tap - UPEI)	80	80	82.12	102.65
T1 (Westroy 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	75	179.68	239.58
T1 (Westroy 138/69 kV Transformer T1)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	109.28	145.71
T1 (Sherbrooke 138/69 kV Transformer T1)	T1 (Westroy 138/69 kV Transformer T1)	75	75	117.16	156.21
T1 (Sherbrooke 138/69 kV Transformer T1)	T3 (Westroy 138/69 kV Transformer T3)	50	50	78.5	157
T1 (Sherbrooke 138/69 kV Transformer T1)	T13 (West Royalty Tap - UPEI)	80	80	90.33	112.91
T1 (Sherbrooke 138/69 kV Transformer T1)	T2 (Westroy 138/69 kV Transformer T2)	75	75	117.16	156.21
T1 (Sherbrooke 138/69 kV Transformer T1)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	96.19	128.25
T2 (Sherbrooke 138/69 kV Transformer T2)	T1 (Westroy 138/69 kV Transformer T1)	75	75	117.17	156.22

Table 43 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 6					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T2 (Sherbrooke 138/69 kV Transformer T2)	T3 (Westroy 138/69 kV Transformer T3)	50	50	78.51	157.02
T2 (Sherbrooke 138/69 kV Transformer T2)	T13 (West Royalty Tap - UPEI)	80	80	90.34	112.92
T2 (Sherbrooke 138/69 kV Transformer T2)	T2 (Westroy 138/69 kV Transformer T2)	75	75	117.17	156.22
T2 (Sherbrooke 138/69 kV Transformer T2)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	96.18	128.24
T13 (Charlottetown North - UPEI)	T15 (Charlottetown North - T15 Tap)	80	80	109.68	137.11
T13 (Charlottetown North - UPEI)	T1 (Westroy 138/69 kV Transformer T1)	75	75	114.33	152.44
T13 (Charlottetown North - UPEI)	T3 (Westroy 138/69 kV Transformer T3)	50	50	76.61	153.21
T13 (Charlottetown North - UPEI)	T15 (West Royalty - T15TAP)	80	80	111.35	139.19
T13 (Charlottetown North - UPEI)	T2 (Westroy 138/69 kV Transformer T2)	75	75	114.33	152.44
T13 (Charlottetown North - UPEI)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	105.21	140.28
T15 (Charlottetown North - T15 Tap)	T13 (Charlottetown North - UPEI)	80	80	114.15	142.69
T15 (Charlottetown North - T15 Tap)	T1 (Westroy 138/69 kV Transformer T1)	75	75	115.69	154.26
T15 (Charlottetown North - T15 Tap)	T3 (Westroy 138/69 kV Transformer T3)	50	50	77.52	155.04
T15 (Charlottetown North - T15 Tap)	T13 (West Royalty Tap - UPEI)	80	80	137.01	171.26
T15 (Charlottetown North - T15 Tap)	T2 (Westroy 138/69 kV Transformer T2)	75	75	115.69	154.26

Table 43 Thermal Criteria Violations under System Normal N-0 and Single Contingency N-1 Conditions for Additional Scenario 6					
Contingency (System Element Lost)	**Violation Location Details**	**Thermal Ratings (MVA)**		**Results**	
		Normal Rating	**Emergency Rating**	**Power Flow (MVA)**	**% Loading**
T15 (Charlottetown North - T15 Tap)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	100.37	133.83
T15 (T15 Tap - West Royalty)	T13 (Charlottetown North - UPEI)	80	80	115.25	144.06
T15 (T15 Tap - West Royalty)	T1 (Westroy 138/69 kV Transformer T1)	75	75	115.57	154.1
T15 (T15 Tap - West Royalty)	T3 (Westroy 138/69 kV Transformer T3)	50	50	77.44	154.88
T15 (T15 Tap - West Royalty)	T13 (West Royalty Tap - UPEI)	80	80	138.1	172.63
T15 (T15 Tap - West Royalty)	T2 (Westroy 138/69 kV Transformer T2)	75	75	115.57	154.1
T15 (T15 Tap - West Royalty)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	100.43	133.91
Y102/Y104 (West Royalty - Marshfield)	T1 (Westroy 138/69 kV Transformer T1)	75	75	111.7	148.93
Y102/Y104 (West Royalty - Marshfield)	T3 (Westroy 138/69 kV Transformer T3)	50	50	74.85	149.69
Y102/Y104 (West Royalty - Marshfield)	T13 (West Royalty Tap - UPEI)	80	80	83.38	104.23
Y102/Y104 (West Royalty - Marshfield)	T2 (Westroy 138/69 kV Transformer T2)	75	75	111.7	148.93
Y102/Y104 (West Royalty - Marshfield)	Tx1 (Lorne Valley 69/138 kV Transformer)	75	75	106.22	141.62

Appendix H Reactive Power Support Devices for PEI Intertie Option 2

Table 44 shows the reactive power devices added in the additional scenarios.

Table 44 Reactive Power Devices for Additional Scenarios

Additional Scenario #	Location where Reactive Power Device Added	Reactive Power Device Size (MVAR	Area
1	West Royalty	20	City
	Clyde River Tap	20	Central
	Borden	90	Central
	Bedeque	45	Central
	Sherbrooke	10	West
	Sherbrooke	10	West
	Alberton	30	West
	Charlottetown	40	City
	Cross Roads	20	East
	Dingwell Mills	15	East
	Victoria Cross	20	East
	West Cap	20	West
3	Borden	20	Central
	Charlottetown	20	City
	Victoria Cross	20	East
	West Cap	20	West
4	West Royalty	50	City
	Borden	205	Central
	Borden	205	Central
	Church Road	30	East
	Clyde River Tap	20	Central
	Bedeque	45	Central
	Sherbrooke	40	West
	Sherbrooke	50	West
	Wellington	10	West
	Alberton	45	West
	Rattenbury	10	Central
	West Royalty	60	City
	Charlottetown	40	City
	Cross Roads	20	East
	Marshfield	20	City

Table 44 Reactive Power Devices for Additional Scenarios			
	Dingwell Mills	30	East
	Victoria Cross	40	East
	West Cap	20	West
6	Borden	30	Central
	Church Road	20	East
	Airport	10	City
	T23T25Tap	10	Central
	Albeny	20	Central
	Scotchfort	20	East
	Borden	40	Central
	Bedeque	20	Central
	Sherbrooke	10	West
	Wellington	20	West
	O'Leary	30	West
	Rattenbury	20	Central
	West Royalty	30	City
	Charlottetown	50	City
	Dingwell Mills	40	East
	Victoria Cross	50	East
	West Cap	20	West

Appendix I Dynamic Results for PEI Intertie Option 2

I.1 Dynamic Study Results

Stantec performed dynamic study for the selected Additional Scenarios.

I.1.1 STUDIED CONTINGENCIES

Table 45 shows the list of contingencies used in dynamic study for the additional scenarios.

Table 45 Contingency Used in Dynamic Study for Additional Scenarios

#	Contingency Type	Contingency Description
1	138 kV Cable	Cable 2
2	138 kV Cable	Cable 3
3	138 kV Transmission Line	Bedeque - West Royalty
4	138 kV Transmission Line	Bedeque - Scotchfort
5	138 kV Transmission Line	Scotchfort – Lorne Valley
6	138 kV Transmission Line	West Royalty – Marshfield
7	138 kV Transmission Line	Charlottetown plant - Crossroad T2
8	138 kV Transmission Line	WSTOCK138 138.00 - Y115SHERB 138.00
9	Generator	CT2
10	Generator	CT3
11	Generator	West Cape Wind
12	Generator	Hermanville Wind

The dynamic study results are presented in the following sections.

I.1.2 ADDITIONAL SCENARIO 1

Figure 13 - Figure 16 shows the dynamic plots for the contingency of 138 kV transmission line between Bedeque and West Royalty.

Figure 13 138 kV Branch Active Power Flows

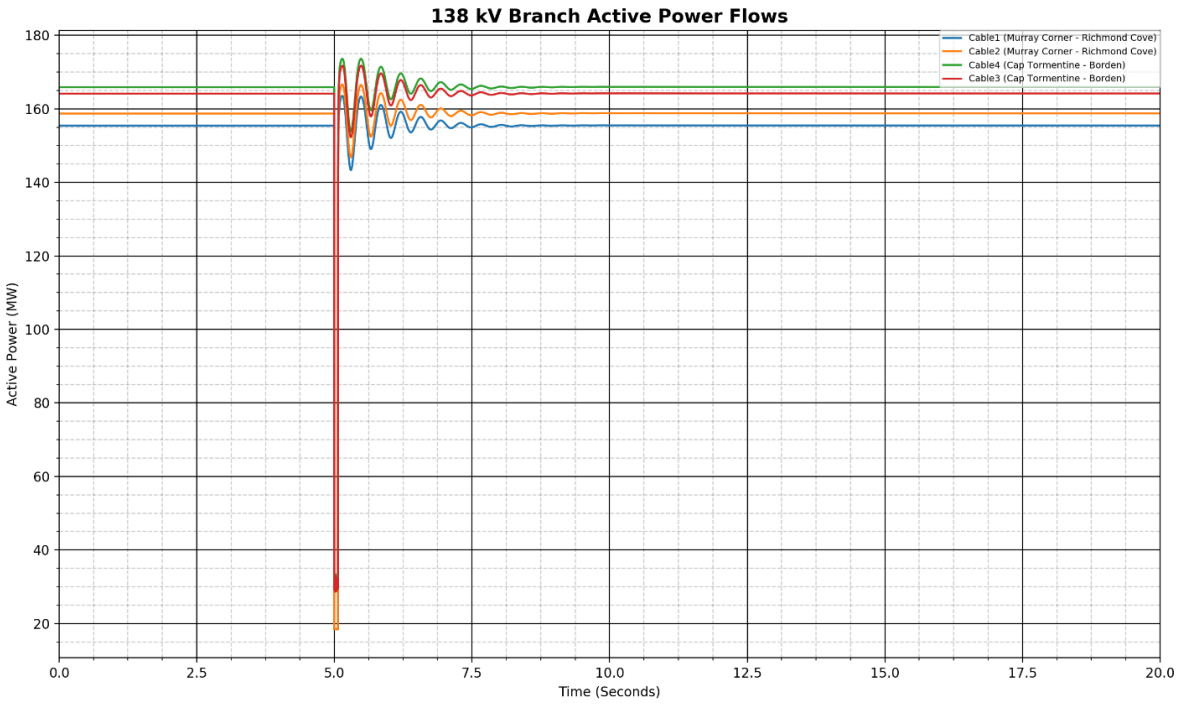


Figure 14 138 kV Branch Reactive Power Flows

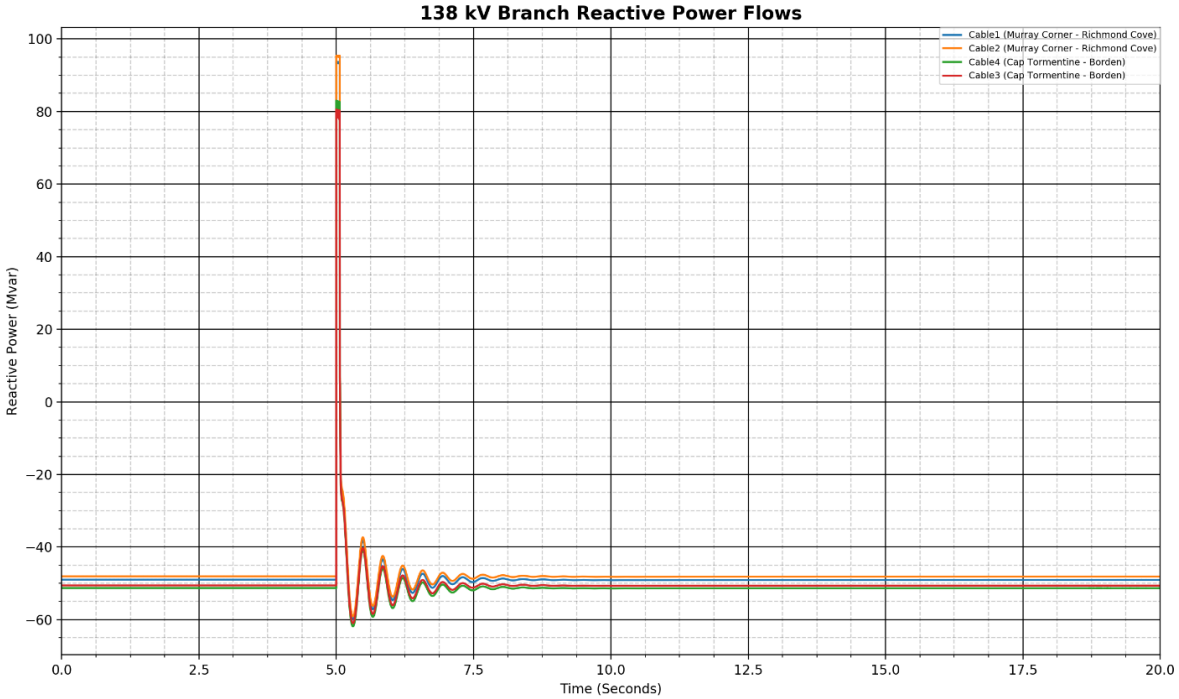


Figure 15 138 kV Frequencies

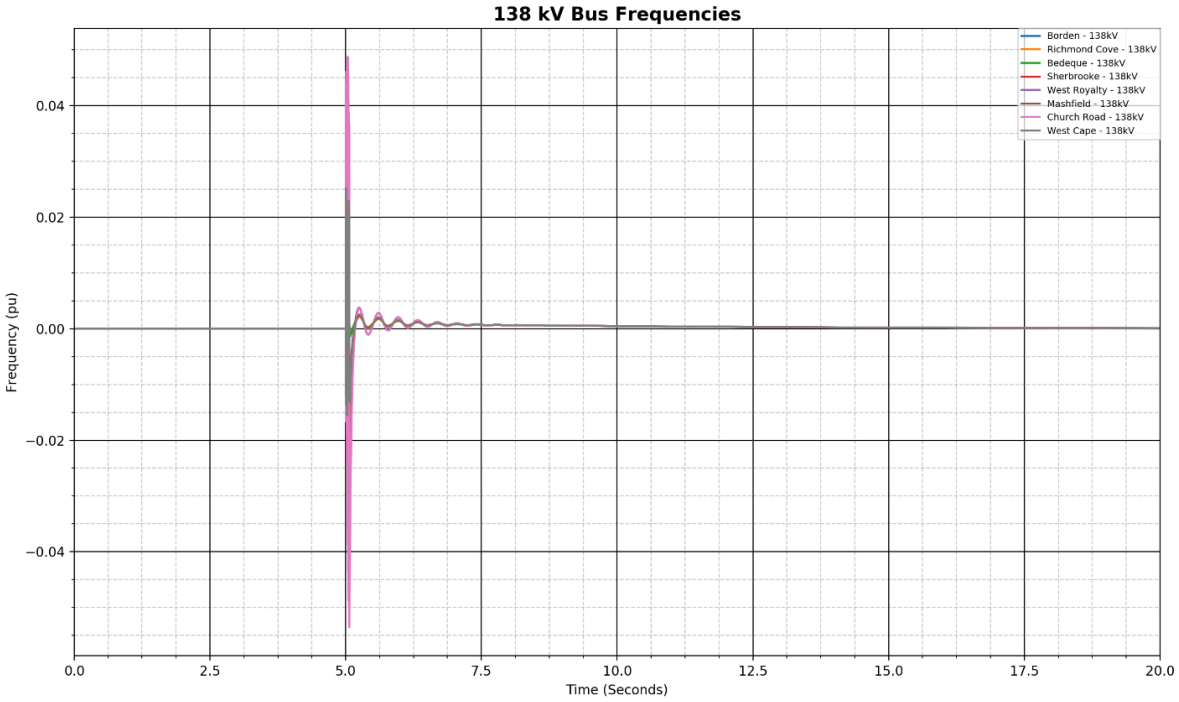
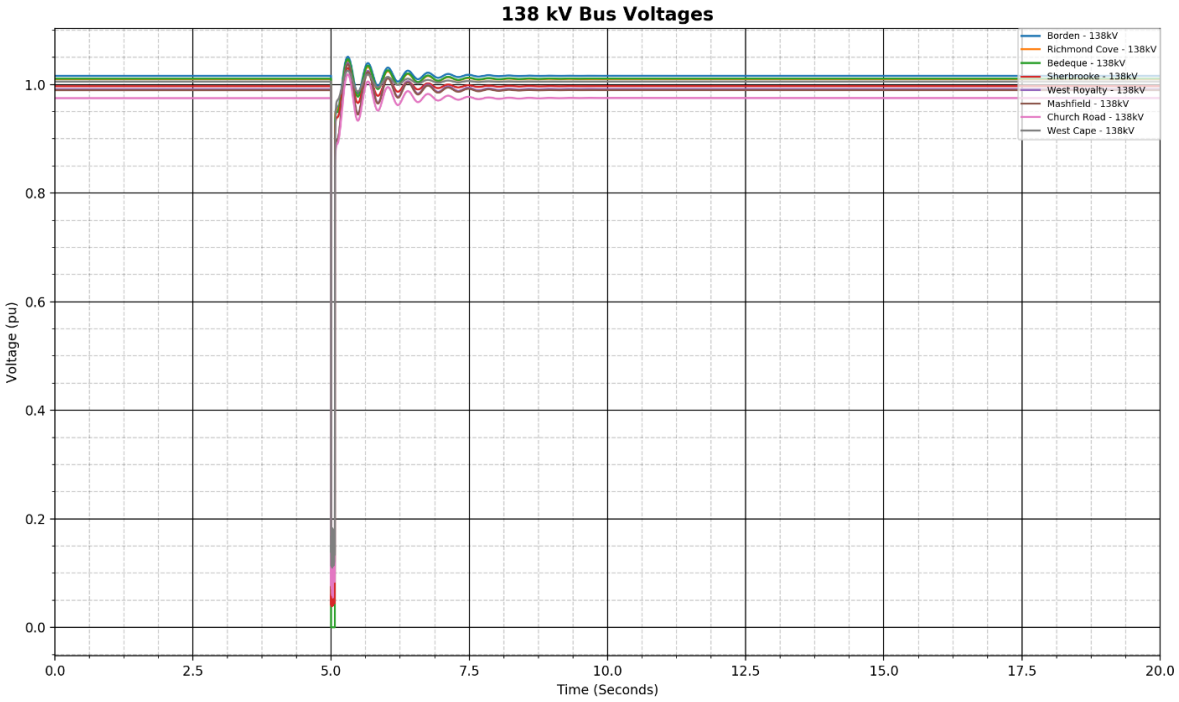


Figure 16 138 kV Bus Voltages



I.1.3 ADDITIONAL SCENARIO 3

Figure 17 - Figure 24 shows the dynamic plots for the contingency of 138 kV transmission line between Bedeque and Scotchford.

Figure 20 138 kV Bus Voltages

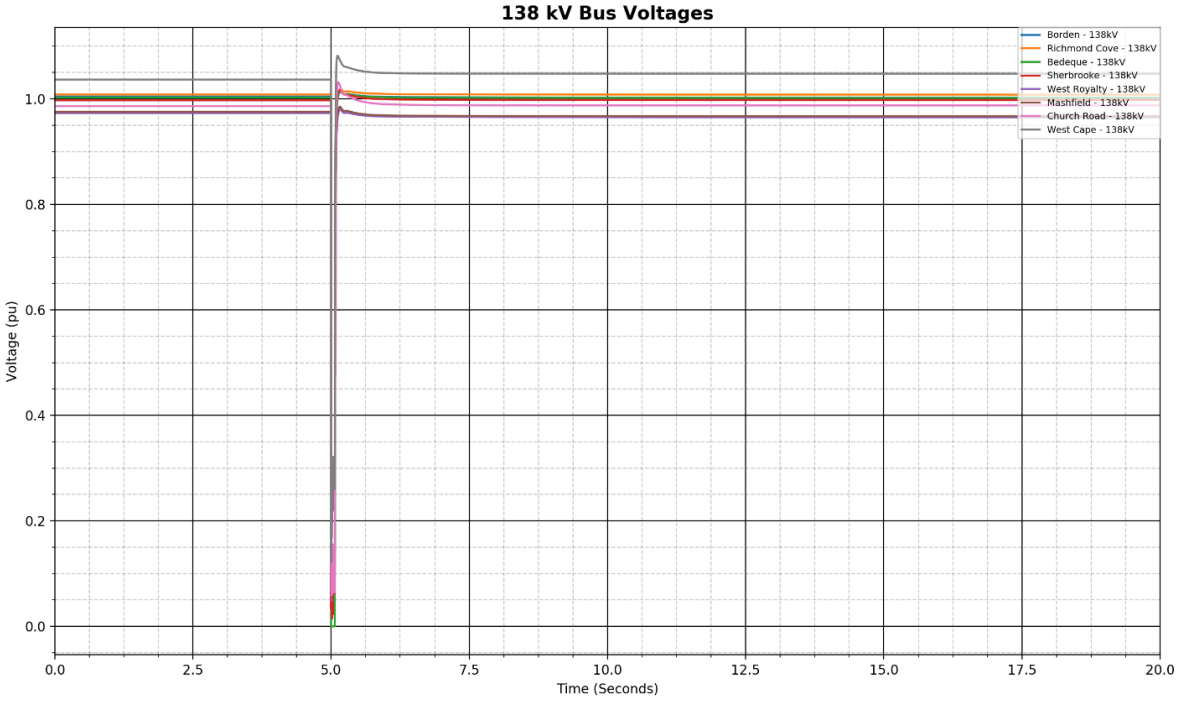


Figure 17 138 kV Branch Active Power Flows

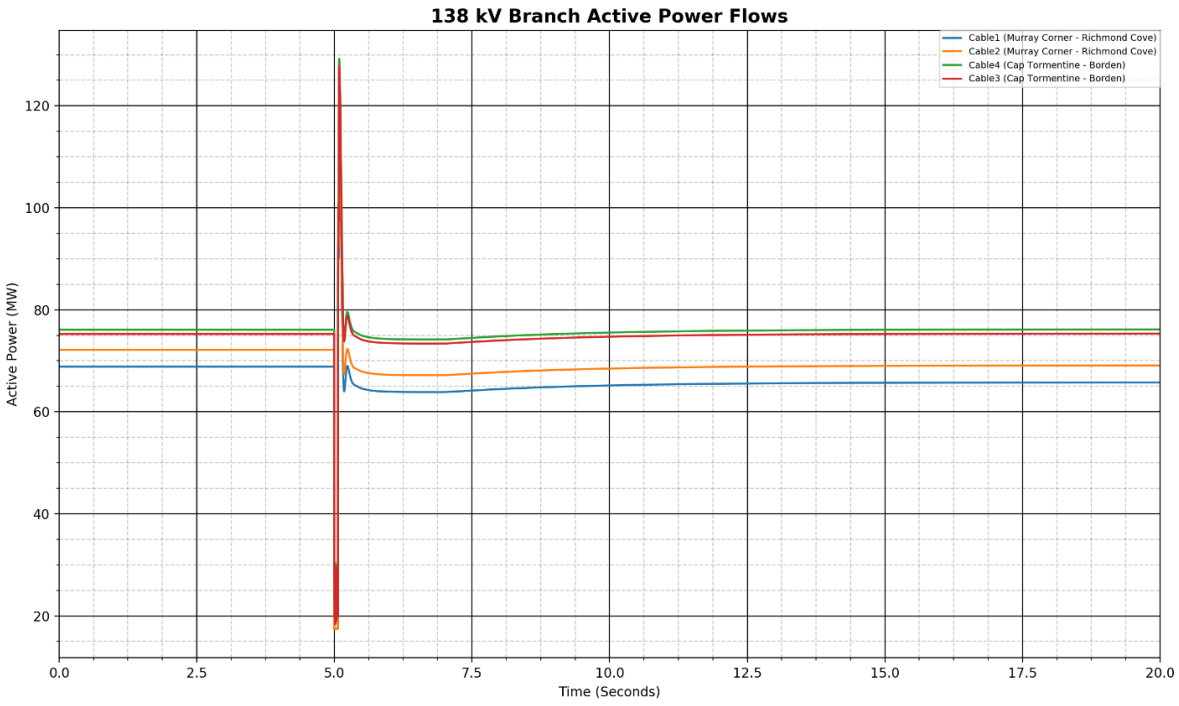


Figure 18 138 kV Branch Reactive Power Flows

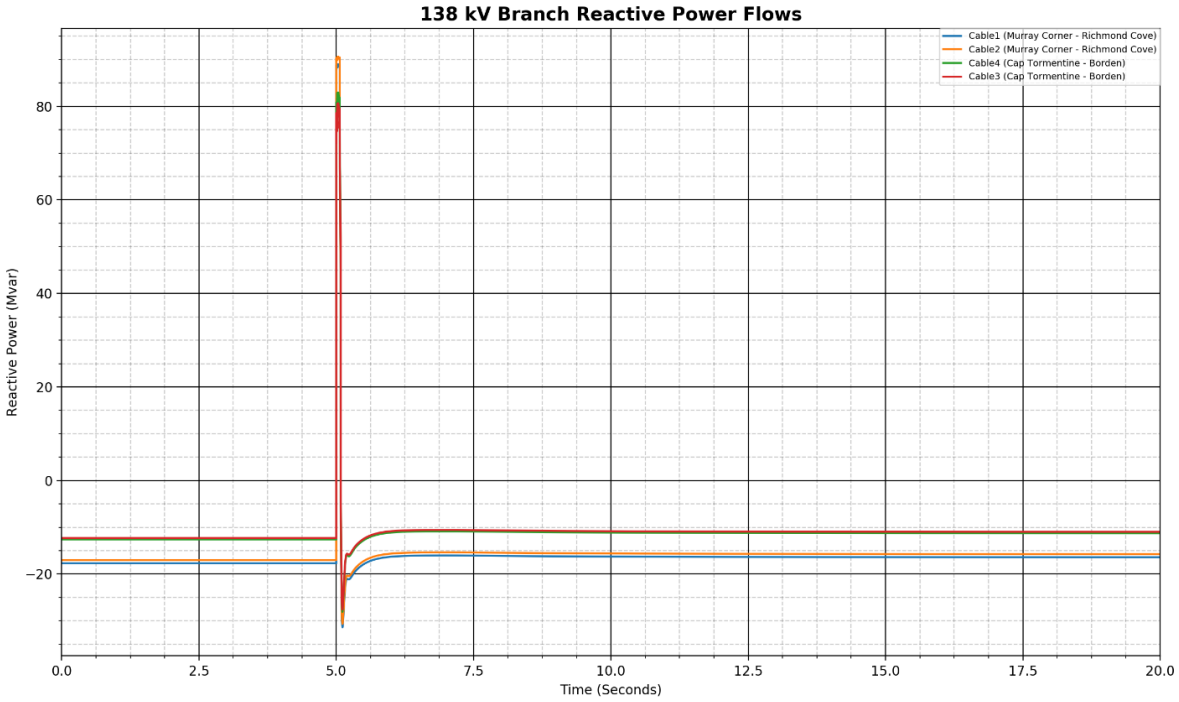


Figure 19 138 kV Frequencies

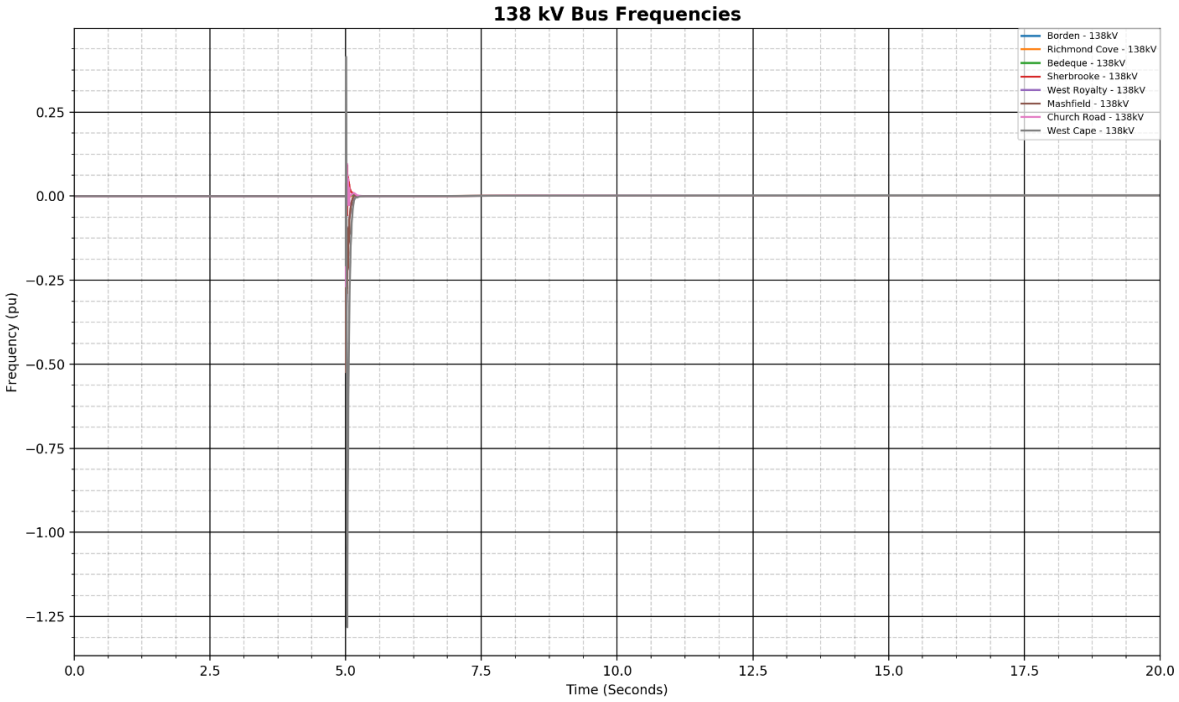
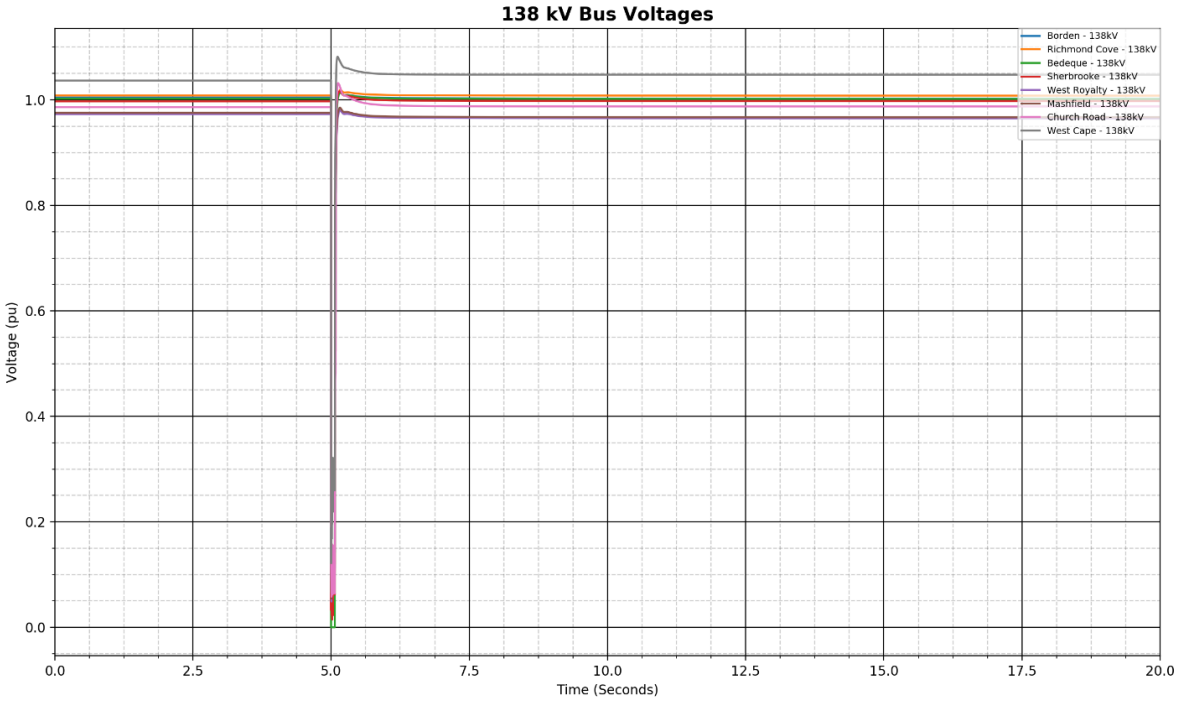


Figure 20 138 kV Bus Voltages



I.1.4 ADDITIONAL SCENARIO 4

Figure 21 - Figure 24 show the dynamic plots for the contingency of 138 kV transmission line between Scotchfort and Lorne Valley.

Figure 21 138 kV Branch Active Power Flows

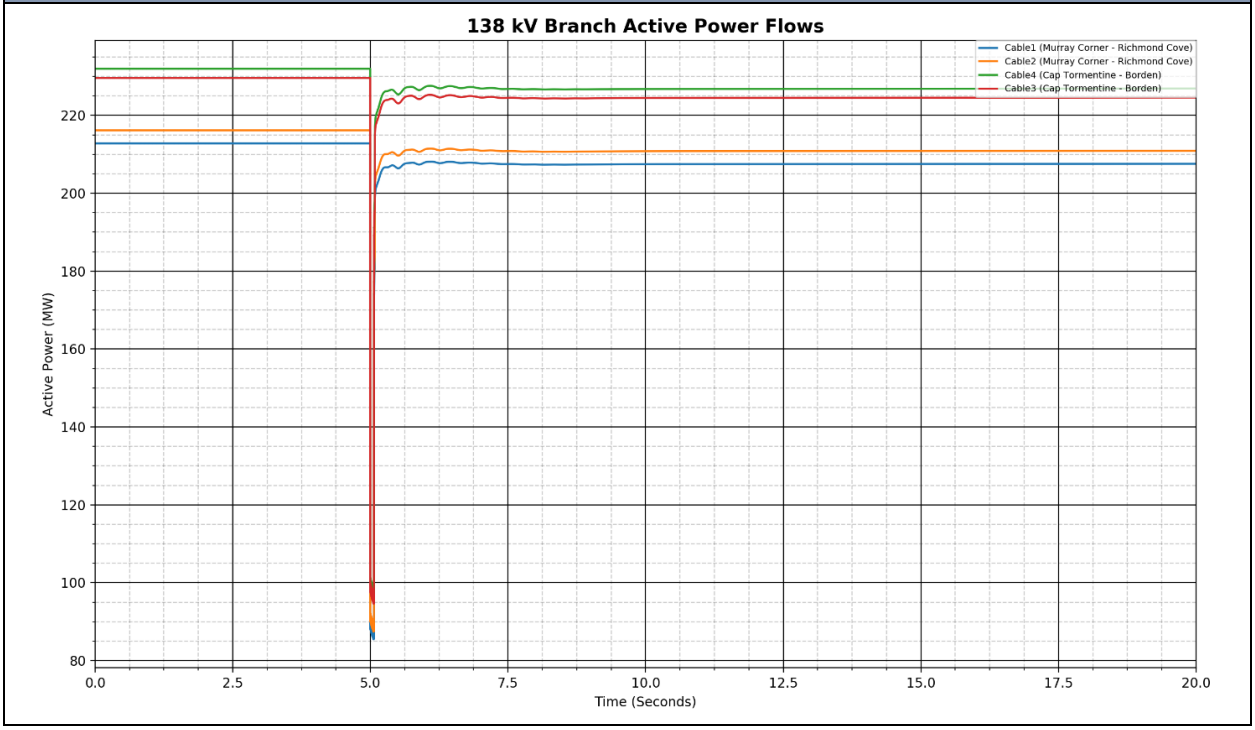


Figure 22 138 kV Branch Reactive Power Flows

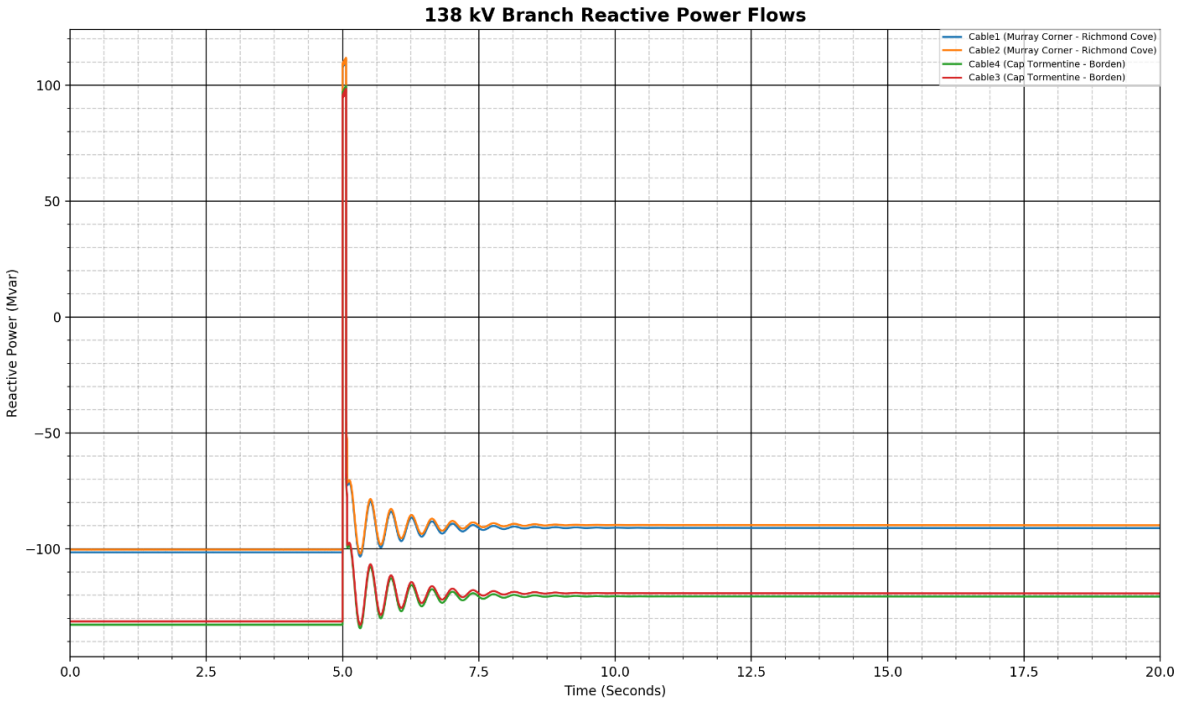


Figure 23 138 kV Frequencies

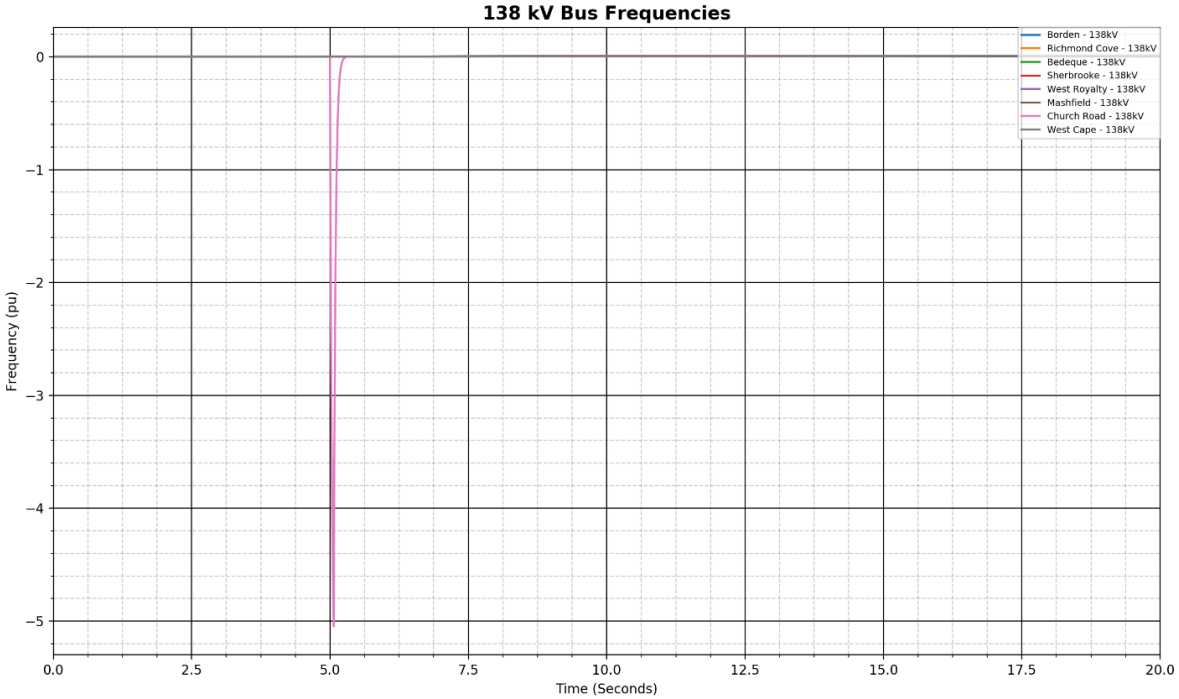
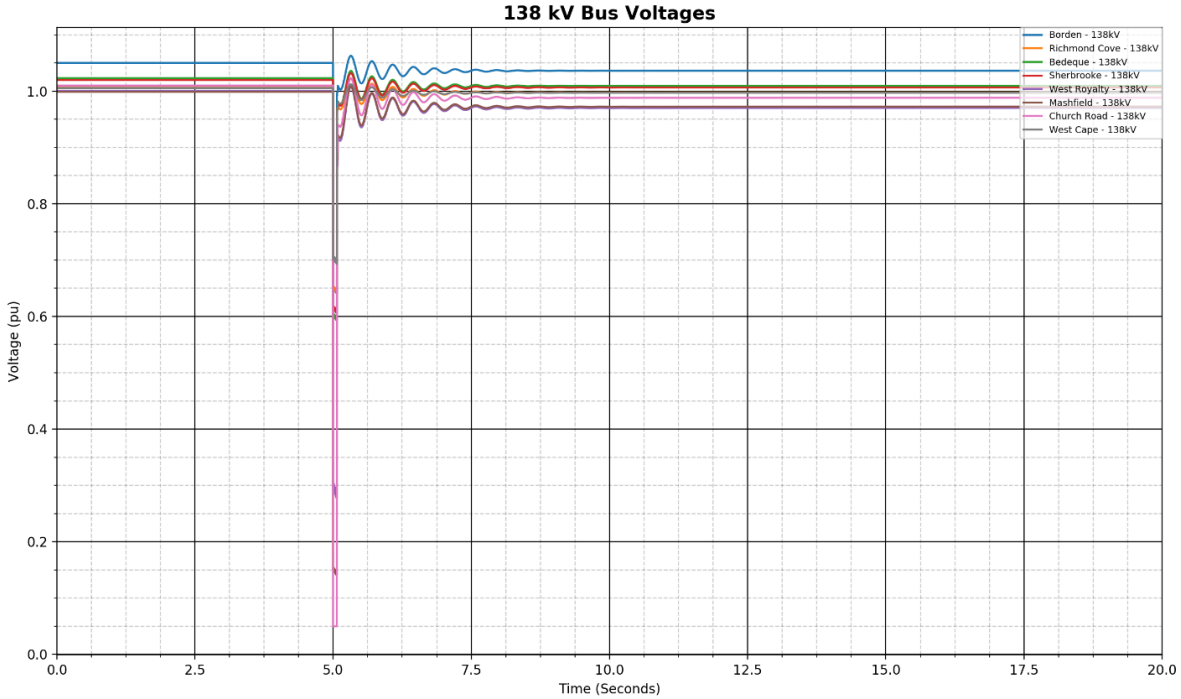


Figure 24 138 kV Bus Voltages



I.1.5 ADDITIONAL SCENARIO 6

Figure 25 - Figure 27 show the dynamic plots for the contingency of Cable 2.

Figure 25 138 kV Branch Active Power Flows

Figure 26 138 kV Branch Reactive Power Flows

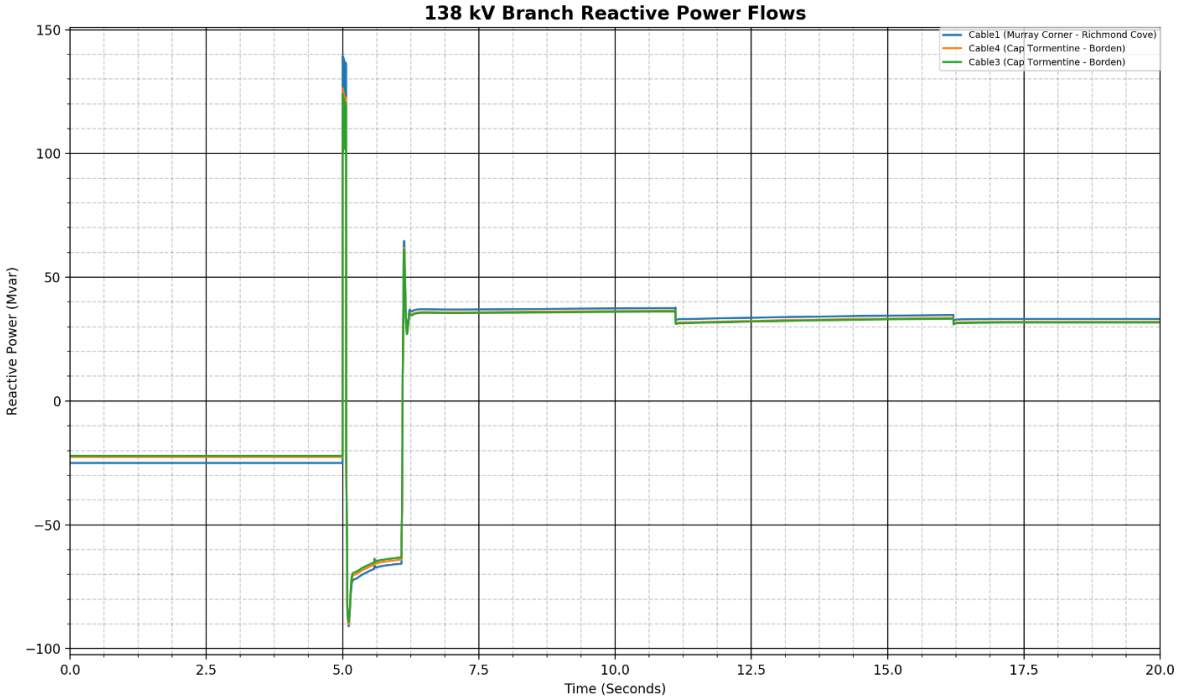
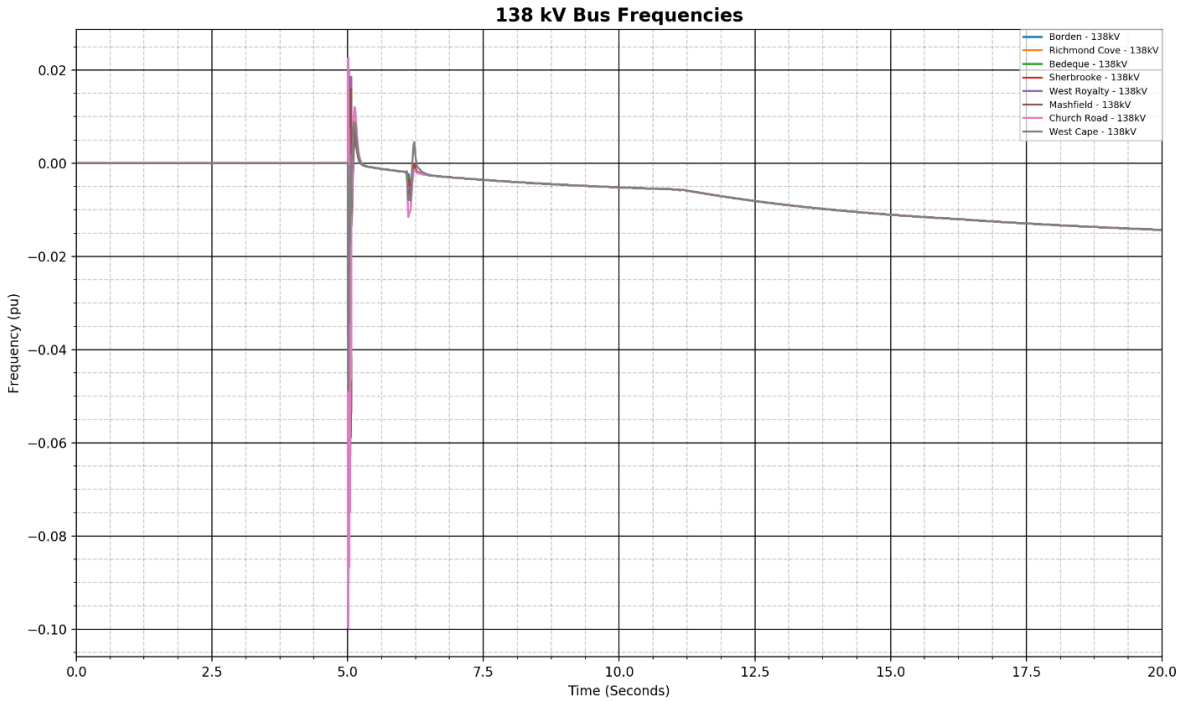
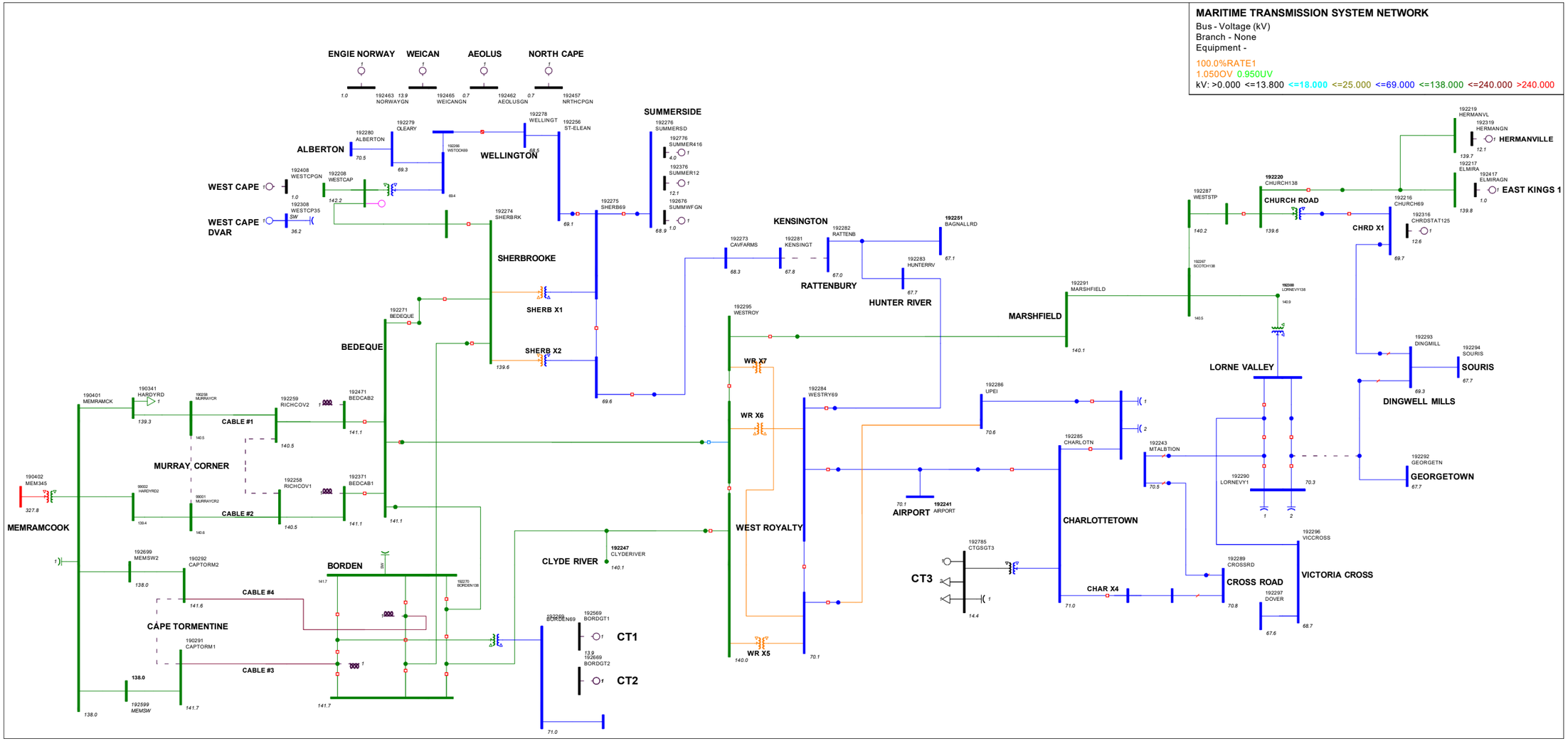


Figure 27 138 kV Frequencies



Appendix J Maritime Transmission System Network


MARITIME TRANSMISSION SYSTEM NETWORK
Bus - Voltage (kV)
Branch - None
Equipment -
100.0%RATE1
1.050OV 0.950UV
kV: >0.000 <=13.800 <=18.000 <=25.000 <=69.000 <=138.000 <=240.000 >240.000
ENGIE NORWAY
WEICAN
AEOLUS
NORTH CAPE
192463 NORWAYGN
192465 WEICANGN
192462 AEOLUSGN
192457 NRTHCPGN
ALBERTON
WELLINGTON
SUMMERSIDE
WEST CAPE
WEST CAPE DVAR
SHERBROOKE
SHERB X1
SHERB X2
BEDEQUE
KENSINGTON
RATTENBURY
HUNTER RIVER
MARSHFIELD
CHURCH ROAD
CHRD X1
HERMANVILLE
EAST KINGS 1
LORNE VALLEY
DINGWELL MILLS
SOURIS
GEORGETOWN
MURRAY CORNER
CABLE #1
CABLE #2
CABLE #3
CABLE #4
MEMRAMCOOK
CAPE TORMENTINE
BORDEN
CLYDE RIVER
CT1
CT2
WR X7
WR X6
WR X5
WEST ROYALTY
AIRPORT
CT3
CHARLOTTETOWN
CHAR X4
CROSS ROAD
VICTORIA CROSS

IR-54 – Attachment 1

Portfolio Net Present Value Study

All our energy.
All the time.

MARITIME ELECTRIC
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MARITIME ELECTRIC COMPANY, LIMITED

ON-ISLAND CAPACITY FOR SECURITY OF SUPPLY PROJECT – DOCKET UE20742
PORTFOLIO NET PRESENT VALUE STUDY

July 24, 2026

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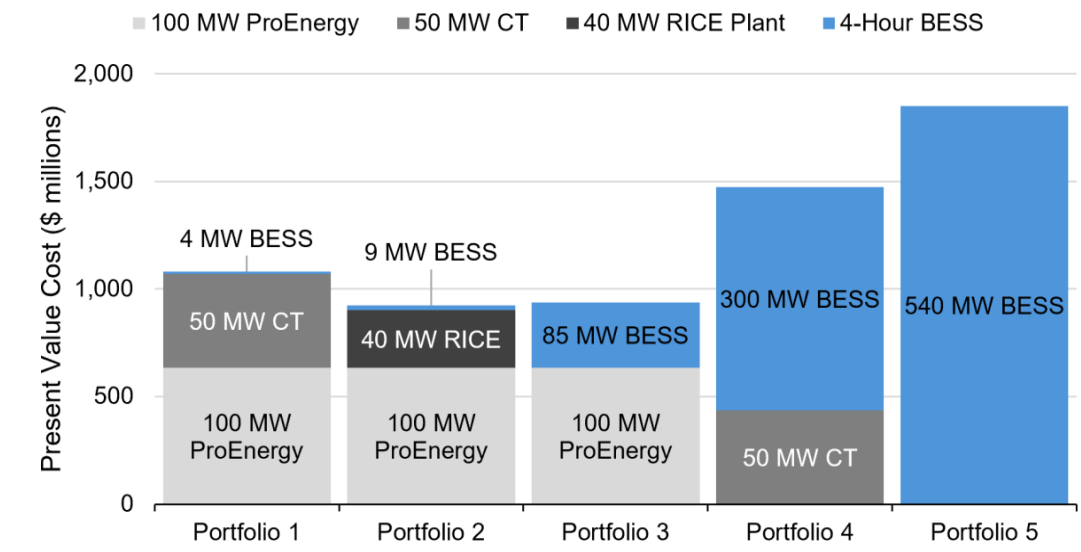
1.0 EXECUTIVE SUMMARY

This Portfolio Net Present Value Study ("Portfolio NPV Study") provides Maritime Electric's updated net present value ("NPV") analysis of potential capacity resource portfolios, including revised assumptions and recent study results, in support of Maritime Electric Company Limited's ("Maritime Electric" or the "Company") proposed On-Island Capacity for Security of Supply Project. The Portfolio NPV Study builds on prior filings and incorporates feedback from the Island Regulatory and Appeals Commission (the "Commission"), Synapse Energy Economics, Inc. ("Synapse"), and the results of a Maritime Electric Resource Adequacy Study prepared for the Company by Energy and Environmental Economics, Inc. ("E3 Study"). The Portfolio NPV Study provides a comprehensive and consistent quantitative comparison of potential capacity resource options (i.e., portfolios) to meet Maritime Electric's 2030 capacity needs.

A key advancement in this study is the use of portfolios developed in the E3 Study that deliver an equivalent reliability contribution, measured by an effective load carrying capability ("ELCC") of 115 megawatts ("MW"). By aligning all portfolios on a common ELCC basis, the study enables a direct comparison of capacity resource costs over a 50-year study period, addressing a limitation of earlier NPV analyses. The study also incorporates several annual operating costs and values that were not included in previous NPV analyses, including thermal generation fuel costs, battery energy storage system ("BESS") charging costs, and BESS energy arbitrage value.

Five portfolios were evaluated, consisting of various combinations of the 100 MW Accelerated On-Island Capacity Development Solution ("ProEnergy Opportunity"), a market-sourced 50 MW combustion turbine ("CT"), a 40 MW reciprocating internal combustion engine ("RICE") plant, and BESS with varying capacities. The results, shown in Figure 1, indicate that portfolios containing the ProEnergy Opportunity provide the lowest overall present value cost. Under the base case, Portfolio 2, comprised of the 100 MW ProEnergy Opportunity, a 40 MW RICE plant and a small BESS, yields the lowest present value cost. Portfolio 3, which replaces the RICE plant with a larger BESS, produces a cost outcome that is only marginally higher. In contrast, portfolios with high levels of BESS capacity result in significantly higher costs, reflecting the declining incremental capacity value of storage as penetration increases.

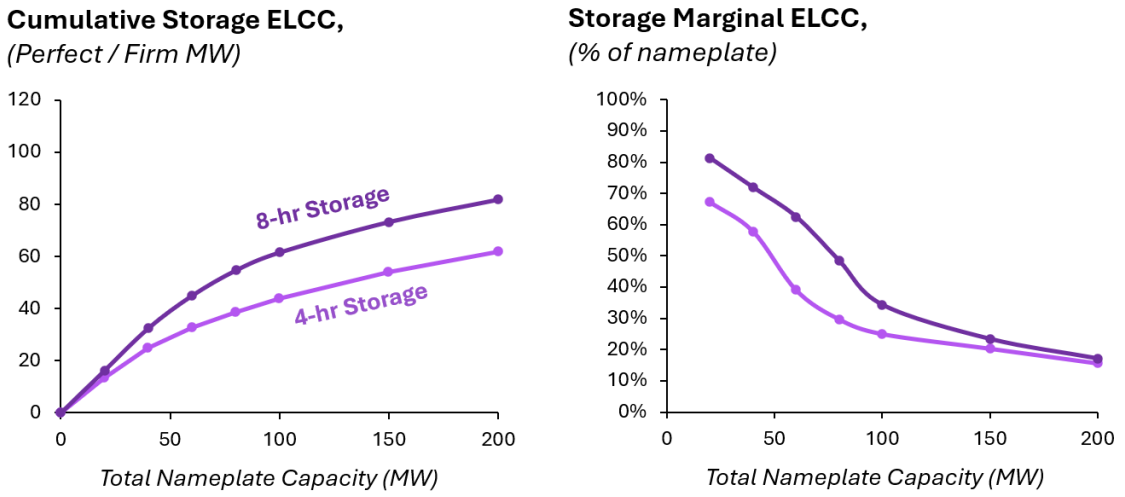
FIGURE 1
Base Case Portfolio Present Value Cost Comparison



The results of the Portfolio NPV Study reflect the ELCC of BESSs relative to CTs and a RICE plant. The E3 Study found that the incremental ELCC of BESSs declined relative to nameplate value as the penetration on Maritime Electric's system increases, as illustrated in Figure 2.[1] As a result, large BESSs are required to provide capacity contributions equivalent to CTs or a RICE plant, which increases the cost of portfolios that rely heavily on BESSs.

[1] E3 Study, Figure 5-7 (page 48).

FIGURE 2
E3 Study BESS ELCC Results



An extensive sensitivity analysis confirms the robustness of these findings across a wide range of assumptions, including variations in capital costs, fuel prices, capacity factors and BESS energy arbitrage value. Portfolios 2 and 3 remain the lowest-cost options in all scenarios, with margins between the two portfolios within 5 per cent under almost all scenarios.

Overall, the study demonstrates that Portfolios 2 and 3, which are anchored by the ProEnergy Opportunity, provide the most cost-effective approach to meeting Maritime Electric's near-term capacity requirements. The relatively small cost differential between these portfolios and the high-level cost estimates used for the RICE plant and BESS support further study and a review of qualitative attributes before a final decision is made for the remaining capacity additions. As demand continues to increase and the existing aged generating assets located in Borden-Carleton are planned for retirement in the early-2030s, further consideration of RICE and BESS additions will be required to meet future capacity obligations.

2.0 INTRODUCTION

On December 18, 2024, Maritime Electric submitted a Supplementary Capital Budget Request Application for the On-Island Capacity for Security of Supply Project ("December 2024 Application") to the Commission, which proposed the addition of 150 MW of dispatchable generating capacity on Prince Edward Island ("PEI").[2] On August 14, 2025, Maritime Electric submitted a Supplemental Filing re: On-Island Capacity for Security of Supply Project ("Supplemental Filing") for a time-sensitive opportunity to secure 100 MW of dispatchable capacity through the ProEnergy Opportunity.[3] Both the December 2024 Application and the Supplemental Filing included NPV analyses for the respective proposed projects.

On April 9, 2026, Synapse filed a report titled Electric System On-Island Capacity Alternatives for Prince Edward Island ("Synapse Report"), prepared for the Commission, that reviewed Maritime Electric's applications.[4] The Synapse Report also included a NPV analysis.

On July 24, 2026, as part of its Responses to Interrogatories from Commission Staff, Maritime Electric submitted the E3 Study that assessed Maritime Electric's electrical supply system and calculated the ELCC of various capacity resources.[5] ELCC is a measure of a generation or storage resource's capacity contribution towards meeting a reliability target. The E3 Study included ten resource portfolio options that address Maritime Electric's 2030 capacity needs.[6]

The purpose of this report is to present the findings of the Portfolio NPV Study and expand on NPV analyses previously filed, while incorporating suggestions from the Commission and Synapse, and results of the E3 Study. The report also includes an extensive sensitivity analysis to test the results of the Portfolio NPV Study under several scenarios.

The report is structured as follows: Section 2.0 of the report provides background information; Section 3.0 presents the Portfolio NPV Study model and methodology used; Section 4.0 presents and discusses the inputs and assumptions used in the model; Section 5.0 presents the results of

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2 Exhibit M-1.
3 Exhibit M-12.
4 Exhibit C-23. The Synapse Report is dated April 9, 2026, but was not sent to Maritime Electric until May 19, 2026.
5 The E3 Study was provided as IR-23 - Attachment 1.
6 Refer to the E3 Study, Section 5.3.6 (page 52).

the Portfolio NPV Study and corresponding sensitivity analysis; and Section 6.0 includes a discussion of the results and their implications for the proposed on-Island capacity additions.

2.1 NPV Analysis Background

Maritime Electric's December 2024 Application included an NPV analysis for each of the three resources considered:[7] (1) a 10 MW 4-hour BESS, (2) a 50 MW CT, and (3) a 90 MW RICE plant. The focus of the NPV analysis was to compare the cost of each resource with the avoided cost of procuring equivalent capacity from New Brunswick Energy Marketing Corporation ("NBEM"). This methodology allowed the costs and benefits of each resource to be compared, despite the resources having different nameplate capacity values and expected useful lives.

In the August 2025 Supplemental Filing, Maritime Electric included an updated NPV analysis for the ProEnergy Opportunity.[8] This NPV analysis followed the same methodology as the December 2024 Application but reflected the cost and characteristics of the ProEnergy Opportunity.

The Synapse Report included an NPV analysis using different BESS inputs and assumptions.[9] Specifically, the analysis included BESS augmentation and replacement strategies to achieve a 50-year service life for large-scale BESS resources (rather than a 20 year useful life). The Synapse NPV analysis did not include avoided costs from NBEM; instead, the BESS results were compared to the ProEnergy Opportunity across a 50-year period.

Since the first NPV analysis was filed, CT capacity factors (i.e., how much they are expected to operate), future diesel fuel prices and the value of energy arbitrage (for BESSs) have been discussed through interrogatories. The Company's Response to IR-5 from Synapse provided a capacity factor forecast for on-Island dispatchable generation.[10] Interrogatory IR-22 from Commission Staff to Maritime Electric asked about diesel fuel supply risks and whether Maritime Electric completed a sensitivity analysis regarding future diesel pricing scenarios (at the time, the Company had not).[11] The cover letter of Maritime Electric's Responses to Additional

7 Exhibit M-1, Confidential Appendix E.
8 Exhibit M-12, Confidential Appendix B.
9 Exhibit C-23, Confidential Appendix A.
10 Exhibit M-15.
11 Exhibit M-29.

Interrogatories from Synapse, and the Synapse Report included estimates for the value of energy arbitrage.[12]

To date, none of the NPV analyses filed have incorporated these variables; however, it has become apparent that a comprehensive NPV analysis, that includes these variables and their sensitivity to change, is required for the Commission to evaluate the merit of the ProEnergy Opportunity and the other on-Island capacity resource options.

The Portfolio NPV Study presented in this report is a comprehensive NPV analysis that expands on previously-filed NPV analyses. The introduction of ELCC results and portfolio options specific to Maritime Electric's system in the E3 Study allows for a true direct quantitative comparison between resource portfolio options with the same capacity value. This is an element that was lacking in previous NPV analyses. In addition, Synapse's proposed BESS replacement methodology allows the Portfolio NPV Study to compare all resources over a 50-year period. Finally, factors such as fuel costs and the value of energy arbitrage have been added to the Portfolio NPV Study, and an extensive sensitivity analysis was completed.

[12] Exhibit M-15 (cover letter, page 2) and Exhibit C-23 (page 31), respectively.

3.0 METHODOLOGY

This Portfolio NPV Study differs from the NPV analyses previously submitted by Maritime Electric and Synapse. Previous NPV analyses evaluated capacity resources individually (e.g., a CT versus a BESS), which introduced comparability challenges because each resource contributes differently towards meeting the Company's capacity requirements based on its ELCC. The Portfolio NPV Study draws on the results of the E3 Study, which presents ten distinct resource portfolios that all have the same ELCC of 115 MW.[13] This enables a true direct quantitative comparison between resource portfolio options with the same capacity contribution. The Portfolio NPV Study focuses on Portfolios 1 through 5, which include 4-hour BESSs, as the portfolios with 8-hour BESSs were more costly (refer to Section 3.3). Portfolios 1 through 5 identified in the E3 Study, which form the basis of the Portfolio NPV Study, are shown in Table 1.[14]

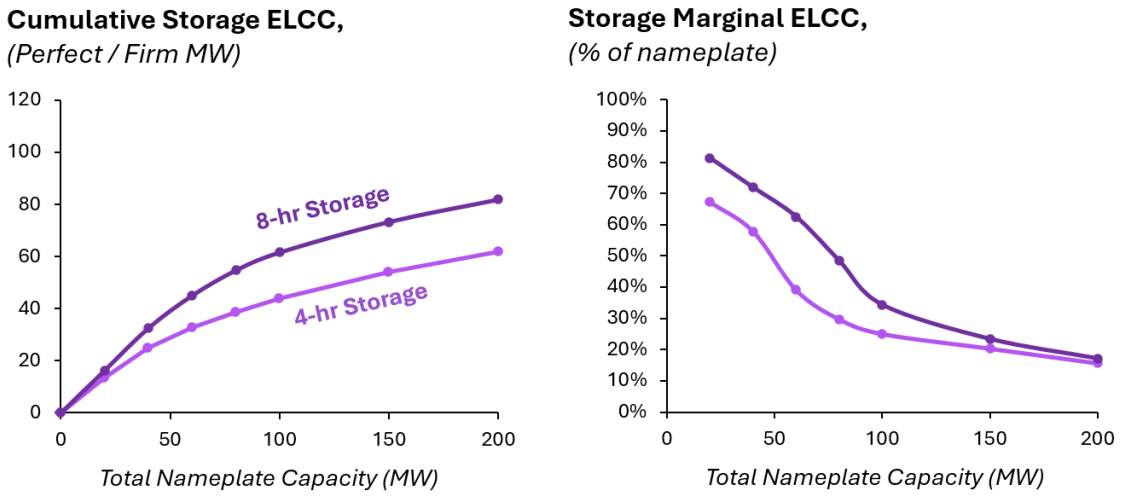
TABLE 1
E3 Study Portfolios 1 through 5 (MW)

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
CTs	3 x 50	2 x 50	2 x 50	1 x 50	-
RICE units	-	2 x 20	-	-	-
4-hour BESS[15]	4	9	85	300	540
Total nameplate capacity	**154**	**149**	**185**	**350**	**540**
ELCC	**115**	**115**	**115**	**115**	**115**

The E3 Study portfolios reflect the ELCC of BESSs relative to CTs and a RICE plant. The E3 Study found that the incremental ELCC of BESSs declined relative to nameplate value as the penetration on Maritime Electric's system increases, as illustrated in Figure 3.[16] As a result, portfolios that rely heavily on BESSs, such as Portfolios 4 and 5, require large BESSs to provide capacity contributions equivalent to portfolios that rely on CTs or a RICE plant, such as Portfolios 1 and 2.

[13] E3 Study, Section 5.3.6 (page 52). 115 MW represents the amount of perfect capacity (i.e., ELCC contribution) required by 2030 to achieve an industry standard loss of load expectation of 0.1 days per year.
[14] Other portfolio options are possible.
[15] In the E3 Study, the BESS resources were modelled as individual 20 MW units to calculate ELCC values.
[16] E3 Study, Figure 5-7 (page 48).

FIGURE 3
E3 Study BESS ELCC Results



3.1 Portfolio NPV Study Portfolios

For the purpose of the Portfolio NPV Study, where at least 100 MW of CTs is included in a portfolio, the 100 MW ProEnergy Opportunity was modelled in place of two 50 MW CTs. Details of the portfolios modelled as part of the Portfolio NPV Study are shown in Table 2.

TABLE 2
Portfolio NPV Study Portfolios 1 through 5 (MW)

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
ProEnergy Opportunity	2 x 50	2 x 50	2 x 50	-	-
Combustion Turbine	1 x 50	-	-	1 x 50	-
RICE plant	-	2 x 20	-	-	-
4-hour BESS[17]	4	9	85	300	540
Total nameplate capacity	**154**	**149**	**185**	**350**	**540**
ELCC	**115**	**115**	**115**	**115**	**115**

The five modeled portfolios represent options for Maritime Electric to exactly meet its minimum capacity need in 2030, prior to the retirement of the CTs located in Borden-Carleton. The portfolios do not suggest that the installation of a small BESS, as is presented in Portfolios 1 (6 MW) and 2

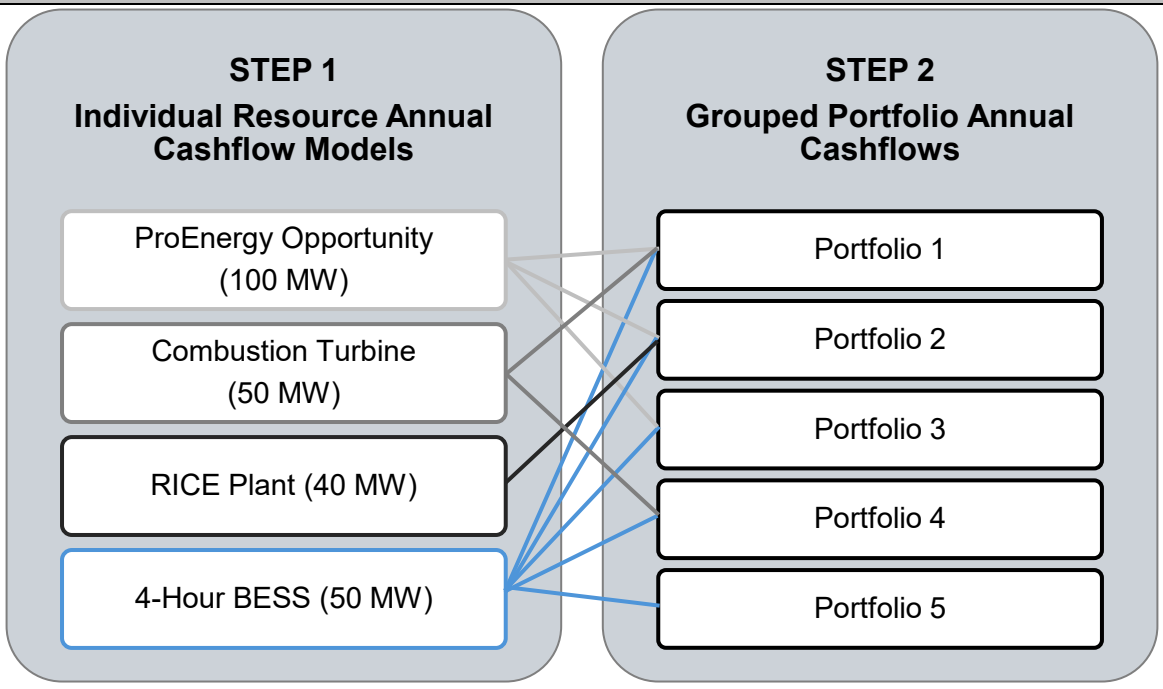
[17] In the Portfolio NPV Study, the cost of a BESS was modelled based on a 50 MW project to align with previous cost estimates and account for economies of scale. The total cost of the BESS capacity was scaled accordingly based on the total BESS capacity in each portfolio.

(4 MW), is a prudent BESS installation, knowing that load growth is expected to continue in the future; rather, the small BESSs in these portfolios is to ensure the ELCC of all five portfolios are equal, which allows for a true direct comparison between the portfolios.

3.2 Annual Cashflows

The capacity resources contained in the five portfolios modelled in the Portfolio NPV Study consist of the 100 MW ProEnergy Opportunity (2 x 50 MW CTs), a 50 MW market-sourced CT, a 40 MW RICE plant, and a 4-hour BESS (of varying size), depending on the portfolio. As illustrated in Figure 4, detailed annual cashflow models were developed for each individual resource in Step 1 and the annual cashflows of each individual resource were grouped together depending on the composition of each portfolio in Step 2. The portfolio annual cashflows were then used to determine the present value cost of each portfolio.

FIGURE 4
Portfolio NPV Study Model Structure



The present value cost for each of the five portfolios are derived directly from the results of the individual resource annual cashflow models in Step 1, with BESS being the only exception. Due to the size (in MW) of the 4-hour BESS being different in each of the five portfolios, the BESS was

modelled as a 50 MW project in Step 1 and scaled according to the BESS size contained in each portfolio in Step 2.[18] The BESS was modeled as a 50 MW project to account for economies of scale for larger BESS projects (e.g., versus multiple smaller 10 MW projects), so that it was not unfairly represented financially in the modeling.

The annual cashflow models for each individual resource (in Step 1) and the annual cashflow models for the grouped portfolios (in Step 2) are provided in Schedule 1 and Schedule 2, respectively.

3.3 4-Hour Versus 8-Hour BESS

The E3 Study included ELCC results for 4- and 8-hour BESSs and Portfolios 6 through 10 included 8-hour BESSs. Although 8-hour BESSs have marginally better ELCC results, they are more expensive than 4-hour BESSs. A comparison of the installed cost and ELCC value of a 50 MW 4-hour and 50 MW 8-hour BESS is shown in Table 3.

TABLE 3
Comparison of 50 MW 4- and 8-Hour BESSs

		50 MW 4-Hour BESS	50 MW 8-Hour BESS
Total Installed Cost ($'000)	A	116,700[19]	200,724[20]
Approximate ELCC from E3 Study[21]	B	29	39
$/kW ELCC	C = A / B	4,024	5,147

Table 3 demonstrates that the additional cost of a 50 MW 8-hour BESS does not justify its marginally better ELCC value; on a per-kilowatt ("kW") ELCC basis, the installation cost of a 50 MW 8-hour BESS is 28 per cent more expensive than a 50 MW 4-hour BESS.[22] Inputs for 8-hour BESSs were tested in the Portfolio NPV Study model to determine whether this finding is applicable to various BESS sizes. The Portfolio NPV Study base case results indicate that Portfolios 1 through 5, which include 4-hour BESSs, had lower or equal present value costs over

[18] For example, Portfolio 1 contains a 15 MW 4-hour BESS; therefore, the annual cashflows of the 50 MW BESS in Step 1 were scaled by a factor of 15 / 50 in Step 2 for Portfolio 1.
[19] Refer to Table 8 (page 18).
[20] Calculated using a factor of 1.72 compared to a 4-hour BESS, derived from the NREL report referenced by Synapse. Cole, Wesley, Vignesh Ramasamy, and Merve Turan. 2025. Cost Projections for Utility-Scale Battery Storage: 2025 Update. National Renewable Energy Laboratory. Factor of 1.72 derived from Figure 2 [page 7].
[21] Refer to the E3 Study, Table 5-5 (page 51).
[22] (5,147 / 4,024) – 1 = 28%

Portfolios 6 through 10, which contained 8-hour BESSs. Therefore, the remainder of this study is focused on the results of Portfolio 1 through 5, that include 4-hour BESSs.

The inputs used to test the 8-hour BESS and the present value cost results of Portfolios 6 through 10 are provided in Schedule 3.

3.4 Study Period

A 50-year study period was selected for the Portfolio NPV Study to provide a common evaluation horizon for all portfolio options and to capture the long-term costs associated with assets having different useful lives. The 50-year study period aligns with the assumed useful life for CTs and a RICE plant, and is consistent with previous Maritime Electric and Synapse NPV analyses. Previous Maritime Electric and Synapse NPV analyses use a useful life of 20 for BESSs. The Synapse Report presents several potential BESS augmentation and replacement approaches to extend the service life of a BESS resource from 20 to 50 years.[23] The Portfolio NPV Study uses Synapse's approach of extending the service life of a BESS resource to 50 years, such that its costs and benefits can be evaluated over the entire 50-year study period.

All resources in the Portfolio NPV Study are assumed to be commissioned in year 1, which is modelled as the present day (2026). Although the commissioning timing of resources may be slightly different, this approach ensures that all resources are evaluated on an equal basis and is consistent with previous Maritime Electric and Synapse NPV analyses.[24]

3.5 BESS Replacement Strategy

Maritime Electric believes that Synapse's approach to the replacement of the BESS "at year 21 and 41, at the full cost of a BESS resource, amortized as 20-year assets" is the most likely and appropriate scenario.[25] Maritime Electric also agrees with Synapse that only a portion of the initial BESS installation cost would be incurred during the BESS replacement due to some assets (e.g., transformer, transmission interconnection, sitework, etc.) having a longer useful life than the battery components. However, Maritime Electric does not agree with the Synapse assumption

[23] Exhibit C-23, page 27.
[24] For example, a BESS is not penalized for having a sooner commissioning timeline than a RICE plant, as early costs in an NPV analysis carry more weight.
[25] Exhibit C-23, page 27, approach #2 and #3.

that “roughly one-half of the capital asset needs replacement.”[26] The National Renewable Energy Laboratory (“NREL”) report referenced by Synapse shows that approximately 84 per cent of the initial BESS costs would be required during replacement.[27] As a result, the replacement cost of BESSs, at year 21 and year 41 was modelled as 84 per cent of the initial cost.

Due to the BESS resource having a useful life of 20 years and the study period being 50 years, at year 50, the final BESS (installed at year 41) is only partially depreciated. To account for the remaining value of the BESS at year 50, the Portfolio NPV Study incorporates a residual value for the BESS at the end of the study period.[28]

3.6 NB Power Avoided Costs

Avoided capacity costs from NBEM were included in previous Maritime Electric NPV analyses to account for the different size and ELCC values of individual capacity resources. For example, Maritime Electric’s NPV analysis included in the December 2024 Application assumed that a 50 MW CT and a 10 MW BESS would avoid 50 MW and 10 MW, respectively, of capacity purchases from NBEM. This was an attempt to facilitate the comparison of different sized resources but introduced complexity and required Maritime Electric to forecast a rate for avoided capacity purchases (in $/MW-month) from NBEM for 50 years.

The five portfolio options presented in the E3 Study have the same total ELCC, therefore, avoided capacity purchases from the development of any of the five portfolios will be equal. The portfolios eliminate the need to include avoided capacity purchases from NBEM in the NPV analysis, which removes a variable with significant uncertainty. The added benefit of not requiring avoided capacity purchases from NBEM in the Portfolio NPV Study is that the Portfolio NPV Study can be made publicly available in its entirety.[29]

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26 Exhibit C-23, page 27, approach #2 and #3.
27 Cole, Wesley, Vignesh Ramasamy, and Merve Turan. 2025. Cost Projections for Utility-Scale Battery Storage: 2025 Update. National Renewable Energy Laboratory. 84 per cent derived from Figure 1 (page 6).
28 The residual value is calculated as the initial cost of the BESS installed at year 41 minus the accumulated depreciation.
29 Previous NPV analyses required redactions due to the NBEM avoided capacity costs being confidential.

3.7 BESS Use-Case Strategy

In Maritime Electric's cover letter to its Responses to Additional Interrogatories from Synapse Energy Economics, filed on November 12, 2025, the Company discussed three use cases for a BESS: (1) energy arbitrage; (2) ancillary services; and (3) capacity resource.[30] The Company stated that the BESS included in its December 2024 Application was intended to be used as a capacity resource during the months of January, February and December, and would provide ancillary services during the remaining months, but the value of energy arbitrage was "negligible".

After reviewing the Synapse Report, Maritime Electric agrees that energy arbitrage could have more value than was previously stated by performing energy arbitrage, but only during days when the difference between the on- and off-peak energy prices is greater than $USD 20/megawatt-hour ("MWh"). One limitation of the Synapse Report, however, is that it does not account for the fact that the BESS cannot be utilized for energy arbitrage while also being utilized as a capacity resource or to meet Maritime Electric's ancillary service requirements. There is still value, however, in using the BESS for energy arbitrage during the months of March to November (inclusive), while it is not being used as a capacity resource, and this was incorporated into the Portfolio NPV Study. Table 4 provides an example of how the 85 MW 4-hour BESS in Portfolio 3 is utilized in the Portfolio NPV Study model.

TABLE 4
Example of BESS Use Case Strategy for Portfolio 3

	Capacity Resource	Ancillary Services	Energy Arbitrage
January, February and December	85 MW	0 MW	0 MW
March to November	0 MW[31]	12.5 MW	72.5 MW

During the months of January, February and December (high load months), the 85 MW BESS is entirely used as a capacity resource. From March to November (inclusive), given that there is more value in using the BESS to meet the Company's ancillary service requirements than for energy arbitrage, the first 12.5 MW of the BESS is prioritized for ancillary services use and the

30 Exhibit M-15.

31 The entire use of the BESS from March to November for ancillary services and energy arbitrage assumes that the capacity is not required during those months. Depending on the size of the BESS, the availability of other capacity resources and changes to load patterns in the future, at least a portion of the BESS may need to be reserved for capacity during the months of March to November. However, the Portfolio NPV Study assumes that the BESS is not required as a capacity resource from March to November to show its maximum potential value.

remaining 72.5 MW is used for energy arbitrage.[32] This use case strategy for the BESS maximizes its value.[33]

The inputs used to model the BESS as a capacity resource, for ancillary services and for energy arbitrage are outlined in Section 4.7, Section 4.8 and Section 4.9, respectively.

3.8 Hourly Market Pricing

In Maritime Electric's cover letter to Responses to Additional Interrogatories from Synapse, filed on November 12, 2025, the Company discussed the use of ISO New England Incorporated ("ISO-NE") *real-time* hourly locational marginal pricing ("LMP") for the *NB External Node* as a reasonable proxy of NBEM's hourly marginal electricity prices (i.e., avoided costs or opportunity costs).[34] ISO-NE real-time hourly LMP data was used to estimate the value of energy arbitrage. The Synapse Report also included an estimate of the value of energy arbitrage based on ISO-NE real-time hourly LMP data.[35]

It is important to note that Maritime Electric does not currently buy and sell energy directly on the ISO-NE market. Rather, the ISO-NE hourly LMP is a proxy for NBEM's hourly marginal electricity prices that can be used to estimate the value that NBEM would assign to energy arbitrage through the Energy Purchase Agreement with Maritime Electric. NBEM has recently confirmed that this approach of estimating energy arbitrage value is reasonable, but informed Maritime Electric that the appropriate proxy for evaluating future hourly marginal electricity prices is the ISO-NE *day-ahead* hourly LMP for the *Internal Hub*.[36] Day-ahead hourly LMP is more appropriate because it would allow energy to be reserved and the use of the BESS to be scheduled one day in advance, based on future energy prices.

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[32] 12.5 MW represents Maritime Electric's total ancillary services requirement, as discussed in Section 6.1 (page 47) of the December 2024 Application. The 12.5 MW is applicable to any BESS size equal to or greater than 12.5 MW, and the calculated remaining capacity is used for energy arbitrage.

[33] For large BESS resources (e.g., those larger 50 MW), where a larger share of the Company's capacity is reliant on BESSs, it is possible that a portion of the BESS is needed as a capacity resource from March to November, which could impact the BESS's ability to be used for energy arbitrage.

[34] Exhibit M-15, cover letter, page 2. Location ID number for the NB External Node is 4010; location name is ".ISALBRYNB345 1."

[35] Exhibit C-23, page 31.

[36] Location ID number for the Internal Hub is 4000; location name is ".H.INTERNAL_HUB." Previous Maritime Electric and Synapse energy arbitrage analyses used real-time hourly pricing for the NB External Node.

The Portfolio NPV Study uses the 2025 ISO-NE day-ahead hourly LMP for the Internal Hub to estimate charging costs for a BESS while being used as a capacity resource and the value of energy arbitrage, as described in Section 4.7.1 and Section 4.9, respectively.

4.0 INPUTS AND ASSUMPTIONS

The Portfolio NPV Study relies on several inputs and assumptions. Maritime Electric has primarily relied on information previously presented to the Commission by the Company or by Synapse when selecting inputs and making assumptions for the Portfolio NPV Study, which are outlined in this section. The inputs and assumptions represent the base case, which is considered as the most likely scenario. Section 5.0 includes the results of the base case and a sensitivity analysis that evaluates the impacts of adjusting a select number of the inputs and assumptions.

4.1 100 MW ProEnergy Opportunity Inputs

The 100 MW ProEnergy Opportunity inputs and references are provided in Table 5.

TABLE 5
100 MW ProEnergy Opportunity Inputs

Input	Value	Reference
Useful life (years)	50	Consistent with previous Maritime Electric and Synapse NPV analyses.
Total installed cost ($'000)	353,372	Exhibit M-28(b), Maritime Electric Capacity Pricing Update Letter to IRAC, Confidential Attachment 1.
Year 1 operation and maintenance cost ($'000)	1,244	Exhibit M-1, Confidential Appendix E, scaled to 100 MW and inflated by 2 years at 2 per cent annually.

4.2 50 MW CT Inputs

The 50 MW CT inputs and references are provided in Table 6.

TABLE 6
50 MW CT Inputs

Input	Value	Reference
Useful life (years)	50	Consistent with previous Maritime Electric and Synapse NPV analyses.
Total installed cost ($'000)	275,000	Updated CT cost estimate from Sargent & Lundy (July 2026).
Year 1 operation and maintenance cost ($'000)	622	Exhibit M-1, Confidential Appendix E, inflated by 2 years at 2 per cent annually.

4.3 40 MW RICE Plant Inputs

The 40 MW RICE plant inputs and references are provided in Table 7.

TABLE 7 40 MW RICE Plant Inputs		
Input	**Value**	**Reference**
Useful life (years)	50	Consistent with previous Maritime Electric NPV analyses.
Total installed cost ($'000)	172,320	Updated RICE plant cost estimate from Sargent & Lundy (July 2026), based on $4,308/kW.
Year-1 operation and maintenance cost ($'000)	743	Exhibit M-1, Confidential Appendix E, scaled to 40 MW and inflated by 2 years at 2 per cent annually.

4.4 50 MW 4-Hour BESS Inputs

The 50 MW 4-hour BESS inputs and references are provided in Table 8.

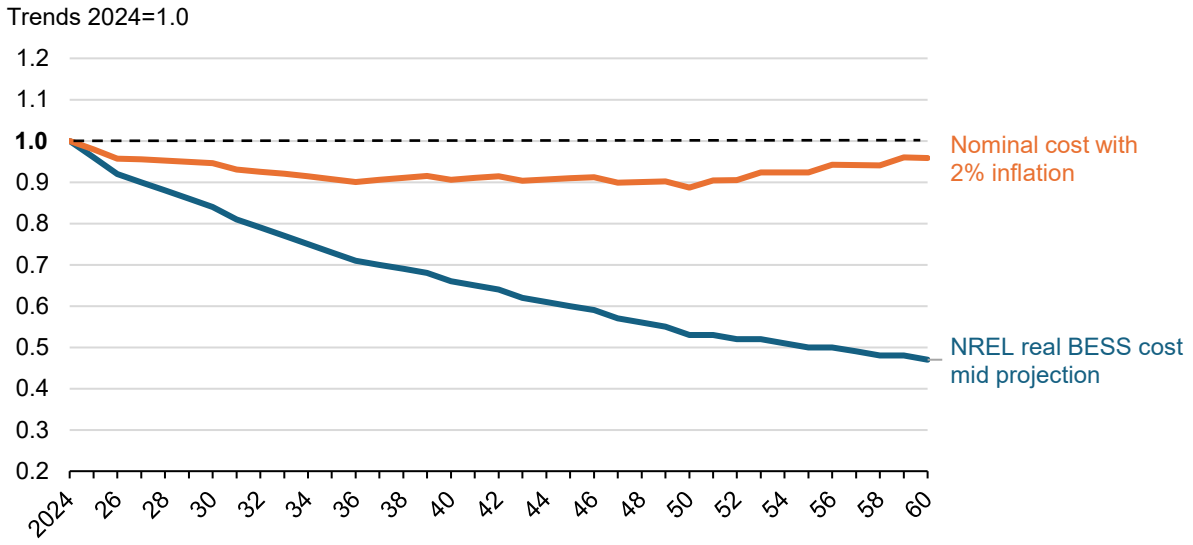
TABLE 8 50 MW 4-Hour BESS Inputs		
Input	**Value**	**Reference**
Useful life (years)	20	Consistent with previous Maritime Electric and Synapse NPV analyses.
Total installed cost ($'000)	116,700	Response to Synapse IR-12(c) (May 2025) and Synapse Report.
Augmentation cost at year 11 ($'000)	8,355	Synapse Report Appendix A, scaled to 50 MW BESS.
Year-1 operation and maintenance cost ($'000)	1,069	Synapse Report Appendix A, scaled to 50 MW BESS.
Roundtrip efficiency	85%	NREL report referenced by Synapse.[37]
Winter charging energy price ($/MWh)	196	Refer to Section 4.7.1.
Load following rate ($/MW-month)	10,535	Exhibit M-1, Table 11 (page 50).
Spinning reserve rate ($/MW-month)	10,523	Exhibit M-1, Table 11 (page 50).
Year-1 4-hour BESS March to November energy arbitrage value per MW ($/MW)	14,599	Refer to Section 4.9.
Replacement BESS (at year 21 and year 41) cost portion of initial BESS cost	84%	Refer to Section 2.5. NREL report referenced by Synapse.[38]

[37] Cole, Wesley, Vignesh Ramasamy, and Merve Turan. 2025. Cost Projections for Utility-Scale Battery Storage: 2025 Update. National Renewable Energy Laboratory (page 12).

[38] Ibid. 84 per cent derived from Figure 1 (page 6).

The cost of replacing the BESS in year 21 and year 41 is based on the cost estimate for the initial BESS in year 1 (i.e., BESS component costs in the future will be equal to BESS component costs today). This is a significant assumption, but is based on the forecast decline in the cost of BESSs being approximately equal to inflation, as illustrated in Figure 5.

FIGURE 5
BESS Cost Projections



NREL data source: Cole, Wesley, Vignesh Ramasamy, and Merve Turan. 2025. Cost Projections for Utility-Scale Battery Storage: 2025 Update. National Renewable Energy Laboratory (page 16).

Figure 5 shows a mid-range BESS cost projection from the NREL report referenced in the Synapse Report. From 2024 to 2060, real BESS installation costs are projected to decline by 53 per cent; however, after accounting for inflation (estimated at 2 per cent annually), nominal BESS installation costs are projected to be approximately equal to present day costs. The assumption that future BESS replacement costs will be approximately equal to present day costs in the Portfolio NPV Study is consistent with the approach used in the Synapse Report.[39] Section 5.1 includes sensitivity tests that evaluate both low (-50%) and high (+25%) BESS replacement costs in year 21 and year 41 to account for the uncertainty of BESS costs in the future.

[39] Exhibit C-23, page 27: "the real cost trends offset inflation such that the nominal costs are roughly the same as seen in the initial 20-year lifetime…"

4.5 Financial Inputs

The financial inputs and references are provided in Table 9.

TABLE 9
Financial Inputs

Input	Value	Reference
Inflation rate	2%	Consistent with previous Maritime Electric and Synapse NPV analyses.
Future project decommissioning costs (% of total project)	10%	Consistent with previous Maritime Electric and Synapse NPV analyses.
Corporate income tax rate	31%	Consistent with previous Maritime Electric and Synapse NPV analyses.
Accelerated capital cost allowance rate (BESS)	30%	Updated from 50% based on Government of Canada updated Capital Cost Allowances Class 43.1 post-2025: https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/sole-proprietorships-partnerships/report-business-income-expenses/claiming-capital-cost-allowance/classes-depreciable-property.html
Normal capital cost allowance rate	8%	Consistent with previous Maritime Electric and Synapse NPV analyses.
Debt ratio	60%	Based on Commission-approved debt ratio. Consistent with previous Maritime Electric and Synapse NPV analyses.
Equity ratio	40%	Based on Commission-approved equity ratio. Consistent with previous Maritime Electric and Synapse NPV analyses.
Debt interest rate	4.91%	Based on Maritime Electric average debt rate. Consistent with previous Maritime Electric and Synapse NPV analyses.
Equity return rate	9.35%	Based on Commission-approved rate of return. Consistent with previous Maritime Electric and Synapse NPV analyses.
Weighted average cost of capital	6.69%	Derived from debt ratio, equity ratio, debt interest rate and equity rate of return. Consistent with previous Maritime Electric and Synapse NPV analyses.

4.6 Thermal Units Annual Generation

Fuel costs for thermal generating units (CTs and the RICE plant), which were not previously included in Maritime Electric NPV analyses, were added to the Portfolio NPV Study. To estimate annual fuel costs for thermal resources, the Portfolio NPV Study model uses an annual capacity

factor as an input. The annual capacity factor is a measure of a unit's total annual generation divided by the maximum total generation potential, if the unit were operating at maximum capacity for all hours of the year (i.e., 8,760 hours).

Historically, the annual capacity factor of Maritime Electric's existing CTs has been below 1 per cent.[40] Over time, the capacity factor of on-Island CTs is expected to increase, as the units are relied upon more frequently as peaking units. As a result, the base case annual capacity factor input used in the Portfolio NPV Study is 3 per cent for thermal resources, which is applied to all 50 years of the study period. Section 5.1 includes sensitivity tests that evaluate both low (1%) and high (5%) annual capacity factor assumptions.

4.6.1 Diesel Price Forecast

Based on Maritime Electric's most recent diesel fuel delivery in February 2026, the fuel cost for the Company's existing Combustion Turbine No. 3 ("CT3") is currently approximately $454/MWh.[41] This rate is used to estimate year-1 fuel costs for CTs (including the ProEnergy Opportunity) in the Portfolio NPV Study. The year-1 fuel cost rate for a RICE plant is estimated as $328/MWh, based on the estimated average heat rate of a RICE plant.[42]

To forecast diesel fuel price escalations, the Portfolio NPV Study relies on a 2026 distillate fuel oil for electric power price forecast from the United States Energy Information Administration ("USEIA").[43] The USEIA forecast is converted from United States dollars ("$US") to Canadian dollars ("$CA"), and the resulting escalation is applied to the year-1 CT and RICE plant fuel-cost rates. The resulting base-case fuel-cost-rates forecast for CTs and the RICE plant is provided in Schedule 4. Section 5.1 includes sensitivity tests that evaluate both low (-15%) and high (+15%) fuel-cost rates. The low and high sensitivities are applied to the fuel-cost rates for all 50 years of the study period.

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40 Refer to Exhibit M-15, Response to IR-5(a), Table IR-5(a)ii (page 13).

41 $454 is an annual average based on the total CT3 fuel consumption and generation in 2025. It is based mainly on part-load operation of CT3, which is less efficient than at full load. For comparison, the rate for wind energy purchased by Maritime Electric is currently $86.59/MWh.

42 Refer to Exhibit M-1, Table 24 (page 120). $454/MWh x (8,400 BTU/kWh / 11,638 BTU/kWh) = $328/MWh.

43 United States Energy Information Administration. Annual Energy Outlook 2026. Table 3: Energy Prices by Sector and Source, United States counterfactual baseline case. The EIA forecast is from 2025 to 2050. The average annual escalation from 2041 to 2050 (10 years) was used for years beyond 2050.

4.7 BESS Capacity Resource Charging

Estimating the annual charging requirements of a BESS is not as straightforward as for thermal resources. Maritime Electric's CTs are primarily treated as peaking units used for emergency backup generation when needed, but a BESS may be used for other reasons. For example, the Portfolio NPV Study assumes that the BESS is used for energy arbitrage to generate economic value during the months of March to November, which would increase its annual capacity factor. As a result, BESS charging costs during the months of January, February and December, while it is used as a capacity resource, are analyzed independently of energy arbitrage and ancillary services.

During the months of January, February and December, when a BESS is being used strictly as a capacity resource, it is reasonable to assume that a BESS's discharge (in MWh) would be approximately the same (on an ELCC basis) as an equivalent thermal generating unit being used as a capacity resource.[44] Currently, approximately 75 per cent of Maritime Electric's annual on-Island thermal generation occurs during the months of January, February and December; therefore, the Portfolio NPV Study assumes that the discharge requirement of a BESS for these months is also 75 per cent of the annual generation from equivalent thermal generating units.[45] An example calculation for a BESS's charge requirements, which accounts for a roundtrip efficiency of 85 per cent, is shown in Table 10.

TABLE 10
BESS Charging Requirements for January, February and December Example Calculation

	CT	4-Hour BESS
Nameplate capacity	50 MW	50 MW
ELCC	36 MW (72%)	30 MW (60%)
Annual capacity factor	3%	-
Annual CT generation	50 MW x 3% x 8,760 = 13,140 MWh	-
Assumed January, February and December generation / BESS discharge requirement	13,140 MWh x 75% = 9,855 MWh	9,855 MWh x (30 MW / 36 MW) = 8,213 MWh
BESS charge requirement	-	8,213 MWh / 85% = 9,662 MWh

[44] For example, if a CT generates a total of 5,000 MWh in January, February and December, it is assumed that a BESS would need to discharge 5,000 MWh for the same period while acting as a capacity resource.

[45] 75 per cent is an approximation based on the historical amount of CT generation during the months of January, February and December. An "equivalent thermal unit" is based on the ELCC of a CT relative to the BESS.

This methodology for calculating BESS charge requirements from January, February and December ensures fair treatment of thermal units and BESSs. For example, evaluating an annual capacity factor sensitivity test of 5 per cent (instead of the 3 per cent base case) for thermal units will not only increase generation and fuel costs for a CT, but will also increase discharge requirements and charging costs for a BESS, accordingly.

4.7.1 BESS Charging Cost

Charging costs associated with a BESS operating as a capacity resource during the months of January, February and December were estimated based on ISO-NE day-ahead hourly LMP for that period, as a proxy for NBEM energy pricing, as discussed in Section 3.8. It is assumed that the BESS would charge during off-peak periods (i.e., 11 p.m. to 5 p.m.);[46] therefore, the average ISO-NE off-peak price for the months of January, February and December 2025 of $200/MWh was used to estimate the year-1 BESS charging cost rate.[47] An example calculation for the year-1 charging costs of a 50 MW BESS is shown in Table 11.

TABLE 11
4-Hour 50 MW BESS Charging Costs for January, February and December
(Example Calculation)

ISO-NE average off-peak price in January, February and December (11 p.m. to 5 p.m.) ($US)	A	$128.9/MWh
$US/$CA exchange rate	B	1.38
NBEM estimated markup (e.g., OATT fees, profit, risk, etc.)	C	10%
Inflation rate	D	2%
Year-1 BESS charging cost rate ($CA)	E = A x B x (1+C) x (1+D)	$200/MWh
BESS charging requirement example (from Table 10)	F	9,938 MWh
Year-1 January, February and December BESS charging cost ($CA)	G = E x F	$1,987,600

The BESS charging cost rate is adjusted using a 2 per cent annual inflation rate for subsequent years.

[46] The off-peak period selected is consistent with the Synapse Report, Table 3 (page 34).
[47] The $200/MWh price includes an NBEM markup of 10 per cent.

4.8 BESS Ancillary Services Value

As discussed in Section 3.7, the first 12.5 MW of a BESS is prioritized for use to meet Maritime Electric's ancillary service requirements during the months of March to November (inclusive), which is consistent with previous Maritime Electric NPV analyses. The 12.5 MW of ancillary services is made up of Load Following (4.7 MW) and Spinning Reserve (7.8 MW).[48] The use of a BESS to provide these ancillary services will avoid costs associated with load following and spinning reserve at current rates of $10,535/MW-month and $10,523/MW-month, respectively. An example calculation of the year-1 value derived from using a BESS for ancillary services is shown in Table 12.

TABLE 12
Example Calculation of Year 1 Value of Ancillary Service from BESS

Ancillary Service	BESS Assignment (MW)	Rate ($/MW-month)	Annual Value
	A	B	C = A x B x 9 months
Load following	4.7	10,535	$445,631
Spinning reserve	7.8	10,523	738,714
TOTAL	**12.5**	**-**	**$1,184,346**

The annual value in year 1 of meeting Maritime Electric's full ancillary services requirement using a BESS during the months of March to November (inclusive) is estimated to be $1,184,346. The ancillary services value is adjusted using a 2 per cent annual inflation rate for subsequent years.

4.9 BESS Energy Arbitrage Value

During the months of March to November (inclusive), the remaining BESS capacity – after the first 12.5 MW used for ancillary services – can be used for energy arbitrage. The value of energy arbitrage was estimated based on 2025 ISO-NE day-ahead hourly LMP, as a proxy for NBEM energy prices, as discussed in Section 3.8. Consistent with the recommendations in the Synapse Report, energy arbitrage is modelled to only occur during days when the ISO-NE on- and off-peak price differential is greater than $20/MWh ($US) to maximize its value. Also consistent with the Synapse Report, the on-peak hours are assumed to be from 5 p.m. to 11 p.m. and all other hours are considered off-peak hours, irrespective of weekdays or holidays.

[48] Refer to Exhibit M-1, Table 11 (page 50).

The ISO-NE day-ahead LMP showed that in 2025 there were 74 days with an on- and off-peak price differential greater than $20/MWh ($US). During those 74 days, the average on-peak price was $95.58/MWh ($US) and the average off-peak price was $49.37/MWh ($US), which can be used to estimate the annual value of energy arbitrage. A table showing the daily differential in on- and off-peak prices for 2025 is included as Schedule 5, with all days with a price differential of $20/MWh ($US) or greater highlighted in green.

An example calculation for the energy arbitrage value from November to March for a 50 MW 4-hour BESS is shown in Table 13.

TABLE 13
4-Hour 50 MW BESS March to November Energy Arbitrage Value

Number of days with on- and off-peak price differential greater than $20/MWh ($US)	A	74 days
Average on-peak price (5 p.m. to 11 p.m.) ($US)	B	$95.58/MWh
Average off-peak price (11 p.m. to 5 p.m.) ($US)	C	$49.37/MWh
Average on- and off-peak price differential ($US)	D = B - C	$46.21/MWh
Charge requirement per day (50 MW x 4 hours / 92.5%)[49]	E	216.2 MWh
Discharge available per day (50 MW x 4 hours x 92.5%)	F	185.0 MWh
Annual charge requirement	G = A x E	16,000 MWh
Annual discharge available	H = A x F	13,690 MWh
Annual off-peak charging cost ($US)	I = C x G	$789,907
Annual on-peak discharge value ($US)	J = B x H	$1,308,480
Total annual energy arbitrage value ($US)	K = J – I	$518,573
$US to $CA exchange rate	L	1.38
Total annual energy arbitrage value ($CA)	M = K x L	$715,630
Annual energy arbitrage value per MW ($CA)	N = M / 50	$14,313/MW
Inflation rate	O	2%
Year 1 energy arbitrage value per MW ($CA)	P = N x (1+O)	$14,599/MW

The annual value in year 1 derived from using a BESS for energy arbitrage during the months of March to November (inclusive) is estimated to be $14,599/MW (i.e., $715,630 per year for a 50 MW 4-hour BESS or $1.4 million per year for a 100 MW 4-hour BESS). This BESS energy

[49] Half of the 85 per cent round trip efficiency is attributable to charging, and half is attributable to discharging. (85% + ((1 - 85%) / 2) = 92.5%.

arbitrage value is comparable to the Synapse Report findings, which estimated that energy arbitrage had a value ranging from $1 million to $2 million for a 100 MW 6-hour BESS.[50]

The BESS energy arbitrage value is adjusted using a 2 per cent annual inflation rate for subsequent years.

[50] Exhibit C-23, page 33.

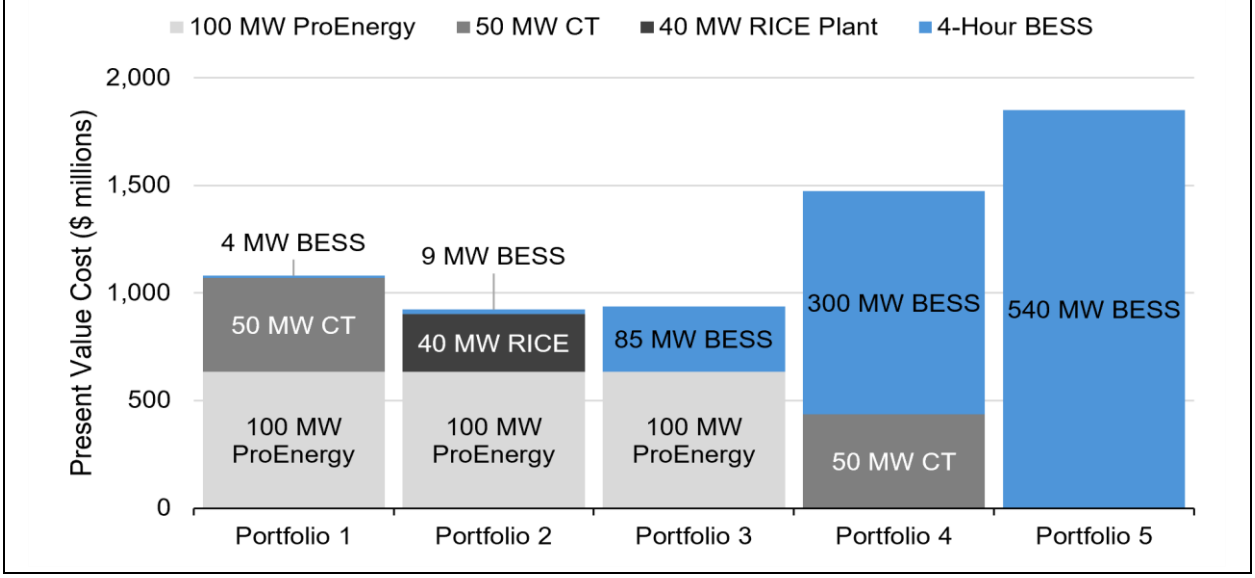
5.0 RESULTS

This section presents the results of the Portfolio NPV Study. The base case results are presented, followed by the sensitivity analysis results. The base case represents what is considered as the most likely scenario. A comparison of the base case present value cost for the five portfolios is shown in Table 14 and Figure 6.

TABLE 14
Base Case Portfolio Present Value Cost Comparison ($ millions)

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
100 MW ProEnergy	635	635	635	-	-
50 MW CT	436	-	-	436	-
40 MW RICE plant	-	267	-	-	-
4-Hour BESS	10	22	302	1,037	1,852
TOTAL	**1,081**	**924**	**936**	**1,474**	**1,852**

FIGURE 6
Base Case Portfolio Present Value Cost Comparison



The results show that Portfolios 2 and 3 have the lowest present value cost, followed by Portfolio 1. The present value cost of Portfolios 4 and 5, which contain significantly more BESS capacity, are significantly higher than the other portfolios. Portfolio 4, which relies on a 50 MW CT and a

300 MW 4-hour BESS, has a present value cost that is 60 per cent higher than Portfolio 2.[51] The results reflect the decreasing ELCC contributions of BESSs at high penetrations on Maritime Electric's system.

5.1 Sensitivity Analysis

A sensitivity analysis was completed to test the present value cost of each portfolio under several scenarios. A summary of the sensitivity tests performed is provided in Table 15.

TABLE 15
Sensitivity Analysis Tests

No.	Sensitivity Test Name	Scenarios		
		Low	Base Case	High
1	ProEnergy Opportunity capital cost	-	+0%	+25%
2	50 MW CT capital cost	-	+0%	+25%
3	40 MW RICE plant capital cost	-	+0%	+25%
4	Initial BESS capital cost[52]	-25%	+0%	+25%
5	Initial BESS capital grant funding	-	0%	25%
6	Replacement BESS capital cost[53]	-25%	+0%	+25%
7	BESS charging cost	-25%	+0%	+25%
8	Energy arbitrage value	-25%	+0%	+25%
9	Thermal generation capacity factor	1%	3%	5%
10	Diesel price forecast adjustment	-15%	+0%	+15%
11	BESS favourable scenario			
	ProEnergy Opportunity capital cost	-	+0%	+25%
	50 MW CT capital cost	-	+0%	+25%
	RICE plant capital cost	-	+0%	+25%
12	High thermal generation capacity factor and diesel price scenario	-	-	-
	Thermal generation capacity factor	-	3%	5%
	Diesel price forecast adjustment	-	+0%	+15%

The sensitivity tests include adjustments to the capital cost of the ProEnergy Opportunity (+25%), 50 MW CT (+25%), 40 MW RICE plant (+25%) and BESS (+/-25%). A +/-25% sensitivity test was selected for the BESS due to recent downward trends of BESS capital costs.

[51] (1,474 / 924) – 1 = 60%.
[52] The Initial BESS Capital Cost sensitivity is also applied to the augmentation cost of the first BESS at year 11.
[53] The Replacement BESS Capital Cost is also applied to the augmentation cost of the second BESS at year 31.

Sensitivity Test No. 11 includes a scenario that combines multiple individual sensitivities that favour BESS. Sensitivity Test No. 12 includes a scenario that combines multiple individual sensitivities that increase the annual fuel cost of thermal generation.

The results of the sensitivity analysis are provided in Table 16. For each sensitivity test, the portfolio with the lowest present value cost and any portfolios with a present value cost within 5 per cent of the lowest present value cost are highlighted in green.

The results show that, under all sensitivity tests, Portfolios 2 or 3 have the lowest present value cost. With the exception of the high initial BESS capital cost test (No. 4-H), under all other scenarios, the margins between Portfolios 2 and 3 are within 5 per cent. Portfolios 4 and 5, which contain significantly more BESS capacity, have significantly higher present value costs under all scenarios.

TABLE 16 Sensitivity Analysis Results Present Value Cost ($ millions)						
		Portfolio				
No.	Sensitivity Test	1	2	3	4	5
-	Base case	1,081	924	936	1,474	1,852
1	High ProEnergy Opportunity capital cost (+25%)	1,177	1,020	1,032	1,474	1,852
2	High 50 MW CT capital cost (+25%)	1,156	924	936	1,548	1,852
3	High 40 MW RICE plant capital cost (+25%)	1,081	971	936	1,474	1,852
4-L	Low initial BESS capital cost (-25%)	1,079	919	885	1,293	1,526
4-H	High initial BESS capital cost (+25%)	1,084	929	988	1,654	2,177
5	High initial BESS capital grant funding (25%)	1,079	919	886	1,296	1,532
6-L	Low replacement BESS capital cost (-25%)	1,080	923	923	1,427	1,768
6-H	High replacement BESS capital cost (+25%)	1,082	925	950	1,520	1,935
7-L	Low BESS charging cost (-25%)	1,080	922	925	1,451	1,818
7-H	High BESS charging cost (-25%)	1,082	926	948	1,496	1,885
8-L	Low energy arbitrage value (-25%)	1,081	924	942	1,494	1,888
8-H	High energy arbitrage value (+25%)	1,081	924	931	1,454	1,815
9-L	Low thermal generation capacity factor (1%)[54]	852	724	754	1,337	1,761
9-H	High thermal generation capacity factor (5%)	1,311	1,124	1,119	1,610	1,942
10-L	Low diesel price forecast adjustment (-15%)	1,030	880	902	1,456	1,852
10-H	High diesel price forecast adjustment (+15%)	1,132	968	971	1,491	1,852
11	BESS favourable scenario: High ProEnergy Opportunity capital cost (+25%) High 50 MW CT capital cost (+25%) High 40 MW RICE plant capital cost (+25%)	1,252	1,067	1,032	1,548	1,852
12	High thermal generation capacity factor and diesel price scenario: High thermal generation capacity factor (5%) High diesel price forecast adjustment (+15%)	1,396	1,197	1,176	1,638	1,942

[54] Portfolios that contain BESS resources are also impacted by the thermal generation capacity factor test because adjusting the capacity factor of thermal generating units increases BESS charging costs while being used as a capacity resource (refer to Section 4.7).

6.0 DISCUSSION

Previous NPV analyses submitted by Maritime Electric and Synapse had contradicting conclusions. Maritime Electric NPV analyses results favoured thermal generating units combined with a small BESS. The Synapse Report indicated that a large BESS could displace the need for the thermal generating units proposed by Maritime Electric. The difference between the Maritime Electric and Synapse NPV conclusions are primarily due to BESS ELCC assumptions.

The Portfolio NPV Study benefits from detailed ELCC results in the E3 Study, which addresses a key source of uncertainty that materially influenced the conclusions of previous NPV analyses. The E3 Study results demonstrate that initial small BESS installments have a relatively high ELCC; however, ELCC contributions diminish as BESS capacity is added.

The E3 Study also calculated the ELCC of thermal generating units, which were previously counted as 100 per cent of their nameplate capacity. The five portfolios presented in the E3 Study and evaluated in this Portfolio NPV Study all have the same ELCC of 115 MW, which allows for a true direct comparison between resource portfolio options – an element that was lacking in previous NPV analyses.

Additionally, the Portfolio NPV Study uses a 50-year study period and relies on one of the proposed BESS replacement strategies in the Synapse Report. This methodology allows the portfolios to be evaluated over the same 50-year service life, despite BESSs having an estimated useful life of 20 years.

Finally, the Portfolio NPV Study included annual fuel costs for thermal generating units and charging costs for a BESS while being used as a capacity resource, as well as an annual value assigned to energy arbitrage for the BESS. In past Maritime Electric and Synapse filings, these annual costs and values were discussed but never directly incorporated into NPV analyses.

The Portfolio NPV Study results demonstrate that Portfolios 2 and 3 had the lowest present value cost under the base case, and either Portfolios 2 or 3 had the lowest present value cost under all sensitivity tests performed. Although the E3 Study and the Portfolio NPV Study only included five

portfolios, and many other resource combinations are possible, the results of the Portfolio NPV Study provides strong justification to pursue the ProEnergy Opportunity; Portfolios 2 and 3, which are anchored by the ProEnergy Opportunity, consistently had the lowest present value cost under all sensitivity tests.

The sensitivity analysis shows that, under almost all test cases, the margin between Portfolios 2 and 3 is small (i.e., within 5 per cent), especially considering that the Portfolio NPV Study is a 50-year study. The difference between the two portfolios is a 40 MW RICE plant (Portfolio 2) and 76 MW of a 4-hour BESS (Portfolio 3).[55] The close margins between the two portfolios and the high-level cost estimates used for the RICE plant and BESS support further study before a final decision is made for the remaining capacity additions.

An important consideration is that the E3 Study and the Portfolio NPV Study represent the Company's minimum capacity needs in 2030 and do not account for the retirement of the two CTs located in Borden-Carleton, which have a total nameplate capacity of 40 MW. Additional capacity beyond the 115 MW contemplated in this study will be required in the near future to address continued load growth and the retirement of the Borden-Carleton CTs. Given the close margins between Portfolios 2 and 3, a combination of RICE and BESS technologies may be a reasonable option to meet future needs and provide diversity to the Company's capacity resource mix.

It is also important to recognize that the Portfolio NPV Study is a quantitative economic analysis. Consideration should be given to the qualitative attributes of capacity resource options, which may provide benefits that were not accounted for in the Portfolio NPV Study.

6.1 Appropriate BESS Size

A significant point of debate throughout the regulatory process and discussions with the Government of PEI has been the appropriate size of BESS for Maritime Electric's system. Portfolios 2 and 3 had the lowest present value cost and included 9 MW and 85 MW 4-hour BESSs, respectively; however, other portfolio options are possible, and additional capacity will be needed soon to address continued load growth and the retirement of the Borden-Carleton CTs. Although the Portfolio NPV Study does not identify the optimal BESS size for Maritime Electric's

[55] 85 MW (Portfolio 3) - 9 MW (Portfolio 2) = 76 MW.

system, the results indicate that an appropriate BESS size is likely between 9 MW, as reflected in Portfolio 2, and 85 MW, as reflected in Portfolio 3.

6.2 Study Limitations

Although the Portfolio NPV Study addresses many limitations of previous NPV analyses and includes an extensive sensitivity analysis to test various scenarios, some limitations remain. Limitations include the inability to capture every event or scenario where a BESS could offset thermal generation, and assumptions associated with the useful life of resources.

Currently, Maritime Electric's CTs are used to generate during NB Power hold-to-schedule directives.[56] Given that hold-to-schedules are short-duration events, it is likely that a BESS would be capable of offsetting CT generation that would otherwise be required for hold-to-schedules. This BESS use case was not modeled in the Portfolio NPV Study because several factors impact the BESS's ability to contribute to hold-to-schedules, including the state of charge and whether it is being used for other purposes at the time (e.g., ancillary services). Although a BESS could be used for hold-to-schedules, the cost savings are expected to be minimal. Hold-to-schedules are forecast to represent only approximately 10 per cent of CT generation in 2033,[57] and a significant portion of the cost of hold-to-schedule generation is currently billed to wind farms due to incorrect wind generation forecasting, which does not represent a cost to Maritime Electric.

Resource useful life assumptions could materially affect the Portfolio NPV Study results; however, the model does not test alternative useful life assumptions. Maritime Electric believes the assumptions used are reasonable and prudent, while recognizing that uncertainty remains regarding the long-term use of certain assets. For example, future restrictions on diesel-fired generation could shorten the useful life of thermal generating units, and BESSs are assumed to have a useful life of 20 years, but the technology is relatively new and assumed lifespans have not been tested. The capability to convert thermal generating units to alternative fuels, such as natural gas or renewable fuels, could mitigate the risk of diesel-fired generation restrictions, but at a cost.

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[56] Hold-to-schedule refers to times when Maritime Electric is required to generate electricity due to a sudden change in energy import requirements that was not scheduled and cannot be fulfilled by NB Power. Refer to Exhibit M-1, Section 7.3 (page 86).

[57] Refer to Exhibit M-1, Table 23 (page 119). 1.6 GWh / 16.7 GWh = 10%.

SCHEDULE 1
Individual Resource Annual Cashflow Models

SCHEDULE 1 – TABLE 1 100 MW ProEnergy Opportunity Annual Cashflows ($ x 1,000)							
Study Year	Amort.	Fixed O & M	Fuel Costs	Debt Interest	Equity Return	Income Taxes	Total
1	3,887	1,244	11,940	10,317	13,097	5,884	46,370
2	7,854	1,269	11,820	10,026	12,728	5,719	49,416
3	7,854	1,295	11,779	9,638	12,236	5,497	48,299
4	7,854	1,320	11,709	9,269	11,767	5,287	47,206
5	7,854	1,347	11,446	8,916	11,320	5,086	45,968
6	7,854	1,374	10,866	8,579	10,891	4,893	44,457
7	7,854	1,401	11,478	8,256	10,481	4,709	44,180
8	7,854	1,429	11,848	7,946	10,088	4,532	43,697
9	7,854	1,458	12,395	7,648	9,710	4,362	43,427
10	7,854	1,487	12,666	7,362	9,346	4,199	42,912
11	7,854	1,517	12,984	7,085	8,994	4,041	42,475
12	7,854	1,547	13,439	6,818	8,655	3,888	42,201
13	7,854	1,578	13,850	6,559	8,327	3,741	41,908
14	7,854	1,610	14,312	6,308	8,008	3,598	41,689
15	7,854	1,642	14,785	6,065	7,699	3,459	41,503
16	7,854	1,675	15,252	5,828	7,399	3,324	41,331
17	7,854	1,708	15,695	5,597	7,106	3,192	41,153
18	7,854	1,742	16,152	5,372	6,820	3,064	41,005
19	7,854	1,777	16,678	5,153	6,541	2,939	40,941
20	7,854	1,813	17,267	4,938	6,269	2,816	40,956
21	7,854	1,849	17,944	4,727	6,001	2,696	41,072
22	7,854	1,886	18,486	4,521	5,739	2,579	41,064
23	7,854	1,924	19,058	4,318	5,482	2,463	41,099
24	7,854	1,962	19,610	4,119	5,229	2,349	41,123
25	7,854	2,001	20,177	3,923	4,980	2,237	41,173
26	7,854	2,041	20,815	3,730	4,735	2,127	41,302
27	7,854	2,082	21,472	3,539	4,493	2,019	41,459
28	7,854	2,124	22,150	3,351	4,255	1,911	41,645
29	7,854	2,166	22,850	3,166	4,019	1,806	41,860
30	7,854	2,210	23,572	2,982	3,786	1,701	42,103
31	7,854	2,254	24,317	2,800	3,555	1,597	42,376
32	7,854	2,299	25,085	2,620	3,326	1,494	42,678
33	7,854	2,345	25,877	2,442	3,100	1,393	43,010

34	7,854	2,392	26,695	2,265	2,876	1,292	43,372
35	7,854	2,440	27,538	2,090	2,653	1,192	43,765
36	7,854	2,488	28,408	1,915	2,432	1,092	44,189
37	7,854	2,538	29,305	1,742	2,212	994	44,645
38	7,854	2,589	30,231	1,570	1,994	896	45,133
39	7,854	2,641	31,186	1,399	1,777	798	45,654
40	7,854	2,694	32,171	1,229	1,561	701	46,209
41	7,854	2,748	33,187	1,060	1,346	605	46,799
42	7,854	2,802	34,236	892	1,132	509	47,424
43	7,854	2,859	35,317	724	919	413	48,085
44	7,854	2,916	36,433	557	707	318	48,783
45	7,854	2,974	37,584	390	495	223	49,519
46	7,854	3,033	38,771	224	285	128	50,295
47	7,854	3,094	39,996	59	75	34	51,110
48	7,854	3,156	41,259	(106)	(135)	(61)	51,967
49	7,854	3,219	42,562	(271)	(344)	(154)	52,866
50	7,854	3,284	43,907	(435)	(552)	(248)	53,809
Total	**388,709**	**105,244**	**1,138,561**	**209,224**	**265,614**	**119,334**	**2,226,685**
PV Cost	**109,125**	**23,744**	**227,109**	**96,760**	**122,839**	**55,188**	**634,765**

SCHEDULE 1 – TABLE 2 50 MW Market CT Annual Cashflows ($ x 1,000)							
Study Year	Amort.	Fixed O & M	Fuel Costs	Debt Interest	Equity Return	Income Taxes	Total
1	3,025	1,244	5,970	8,029	10,193	4,579	33,040
2	6,112	1,269	5,910	7,802	9,905	4,450	35,449
3	6,112	1,295	5,890	7,501	9,522	4,278	34,597
4	6,112	1,320	5,854	7,213	9,157	4,114	33,771
5	6,112	1,347	5,723	6,939	8,809	3,958	32,887
6	6,112	1,374	5,433	6,676	8,476	3,808	31,879
7	6,112	1,401	5,739	6,425	8,157	3,665	31,499
8	6,112	1,429	5,924	6,184	7,851	3,527	31,027
9	6,112	1,458	6,198	5,952	7,556	3,395	30,671
10	6,112	1,487	6,333	5,729	7,273	3,268	30,201
11	6,112	1,517	6,492	5,514	7,000	3,145	29,779
12	6,112	1,547	6,720	5,306	6,735	3,026	29,446
13	6,112	1,578	6,925	5,104	6,480	2,911	29,110
14	6,112	1,610	7,156	4,909	6,232	2,800	28,818
15	6,112	1,642	7,392	4,720	5,992	2,692	28,549
16	6,112	1,675	7,626	4,535	5,758	2,587	28,292
17	6,112	1,708	7,848	4,356	5,530	2,484	28,038
18	6,112	1,742	8,076	4,181	5,308	2,385	27,803
19	6,112	1,777	8,339	4,010	5,091	2,287	27,615
20	6,112	1,813	8,633	3,843	4,878	2,192	27,470
21	6,112	1,849	8,972	3,679	4,670	2,098	27,380
22	6,112	1,886	9,243	3,518	4,466	2,007	27,232
23	6,112	1,924	9,529	3,360	4,266	1,917	27,108
24	6,112	1,962	9,805	3,205	4,069	1,828	26,982
25	6,112	2,001	10,089	3,053	3,876	1,741	26,872
26	6,112	2,041	10,407	2,903	3,685	1,656	26,803
27	6,112	2,082	10,736	2,754	3,497	1,571	26,752
28	6,112	2,124	11,075	2,608	3,311	1,488	26,717
29	6,112	2,166	11,425	2,463	3,127	1,405	26,699
30	6,112	2,210	11,786	2,321	2,946	1,324	26,698
31	6,112	2,254	12,158	2,179	2,766	1,243	26,712
32	6,112	2,299	12,542	2,039	2,589	1,163	26,744
33	6,112	2,345	12,939	1,900	2,412	1,084	26,792
34	6,112	2,392	13,347	1,763	2,238	1,005	26,857
35	6,112	2,440	13,769	1,626	2,064	928	26,938
36	6,112	2,488	14,204	1,491	1,892	850	27,037

37	6,112	2,538	14,653	1,356	1,721	773	27,153
38	6,112	2,589	15,115	1,222	1,552	697	27,287
39	6,112	2,641	15,593	1,089	1,383	621	27,438
40	6,112	2,694	16,086	957	1,215	546	27,608
41	6,112	2,748	16,594	825	1,047	471	27,796
42	6,112	2,802	17,118	694	881	396	28,003
43	6,112	2,859	17,659	563	715	321	28,229
44	6,112	2,916	18,216	433	550	247	28,474
45	6,112	2,974	18,792	304	386	173	28,740
46	6,112	3,033	19,385	175	222	100	29,026
47	6,112	3,094	19,998	46	58	26	29,334
48	6,112	3,156	20,630	(83)	(105)	(47)	29,663
49	6,112	3,219	21,281	(211)	(267)	(120)	30,014
50	6,112	3,284	21,953	(338)	(430)	(193)	30,388
Total	**302,500**	**105,244**	**569,281**	**162,822**	**206,705**	**92,867**	**1,439,418**
PV Cost	**84,923**	**23,744**	**113,554**	**75,300**	**95,595**	**42,949**	**436,065**

SCHEDULE 1 – TABLE 3 40 MW RICE Plant Annual Cashflows ($ x 1,000)							
Study Year	**Amort.**	**Fixed O & M**	**Fuel Costs**	**Debt Interest**	**Equity Return**	**Income Taxes**	**Total**
1	1,896	743	3,447	5,031	6,387	2,869	20,373
2	3,830	758	3,413	4,889	6,207	2,789	21,885
3	3,830	773	3,401	4,700	5,967	2,681	21,351
4	3,830	789	3,380	4,520	5,738	2,578	20,835
5	3,830	804	3,305	4,348	5,520	2,480	20,287
6	3,830	820	3,137	4,184	5,311	2,386	19,668
7	3,830	837	3,314	4,026	5,111	2,296	19,414
8	3,830	854	3,421	3,875	4,919	2,210	19,108
9	3,830	871	3,579	3,730	4,735	2,127	18,871
10	3,830	888	3,657	3,590	4,557	2,047	18,569
11	3,830	906	3,749	3,455	4,386	1,971	18,296
12	3,830	924	3,880	3,325	4,221	1,896	18,075
13	3,830	942	3,999	3,198	4,060	1,824	17,854
14	3,830	961	4,132	3,076	3,905	1,754	17,659
15	3,830	980	4,269	2,957	3,754	1,687	17,477
16	3,830	1,000	4,403	2,842	3,608	1,621	17,304
17	3,830	1,020	4,531	2,729	3,465	1,557	17,133
18	3,830	1,040	4,663	2,620	3,326	1,494	16,973
19	3,830	1,061	4,815	2,513	3,190	1,433	16,842
20	3,830	1,083	4,985	2,408	3,057	1,373	16,735
21	3,830	1,104	5,181	2,305	2,927	1,315	16,661
22	3,830	1,126	5,337	2,205	2,799	1,257	16,554
23	3,830	1,149	5,502	2,106	2,673	1,201	16,461
24	3,830	1,172	5,662	2,009	2,550	1,146	16,367
25	3,830	1,195	5,825	1,913	2,429	1,091	16,283
26	3,830	1,219	6,009	1,819	2,309	1,037	16,223
27	3,830	1,243	6,199	1,726	2,191	984	16,174
28	3,830	1,268	6,395	1,634	2,075	932	16,134
29	3,830	1,294	6,597	1,544	1,960	880	16,104
30	3,830	1,320	6,805	1,454	1,846	829	16,084
31	3,830	1,346	7,020	1,365	1,734	779	16,074
32	3,830	1,373	7,242	1,278	1,622	729	16,073
33	3,830	1,400	7,471	1,191	1,512	679	16,083
34	3,830	1,428	7,707	1,105	1,402	630	16,102
35	3,830	1,457	7,950	1,019	1,294	581	16,131
36	3,830	1,486	8,202	934	1,186	533	16,170

37	3,830	1,516	8,461	850	1,079	485	16,219
38	3,830	1,546	8,728	766	972	437	16,279
39	3,830	1,577	9,004	682	866	389	16,348
40	3,830	1,609	9,288	599	761	342	16,429
41	3,830	1,641	9,581	517	656	295	16,520
42	3,830	1,674	9,884	435	552	248	16,622
43	3,830	1,707	10,196	353	448	201	16,736
44	3,830	1,741	10,518	272	345	155	16,860
45	3,830	1,776	10,851	190	242	109	16,997
46	3,830	1,812	11,194	109	139	62	17,145
47	3,830	1,848	11,547	29	36	16	17,306
48	3,830	1,885	11,912	(52)	(66)	(30)	17,479
49	3,830	1,922	12,288	(132)	(168)	(75)	17,665
50	3,830	1,961	12,676	(212)	(269)	(121)	17,865
Total	**189,552**	**62,849**	**328,713**	**102,027**	**129,525**	**58,192**	**870,859**
PV Cost	**53,214**	**14,179**	**65,568**	**47,185**	**59,902**	**26,912**	**266,960**

SCHEDULE 1 – TABLE 4 50 MW 4-Hour BESS Annual Cashflows ($ x 1,000)						
Study Year	Amort.	Fixed O & M	Debt Interest	Equity Return	Income Taxes	Total
1	3,209	1,069	3,307	4,199	4,400	16,184
2	6,587	1,090	3,001	3,810	7,123	21,612
3	6,587	1,112	2,677	3,399	4,382	18,157
4	6,587	1,134	2,410	3,060	2,463	15,654
5	6,587	1,157	2,183	2,771	1,120	13,818
6	6,587	1,180	1,984	2,518	179	12,448
7	6,587	1,203	1,804	2,290	(480)	11,406
8	6,587	1,227	1,638	2,080	(941)	10,592
9	6,587	1,252	1,482	1,881	(1,264)	9,939
10	6,587	1,277	1,332	1,692	(1,490)	9,398
11	7,005	1,302	1,415	1,796	(1,007)	10,512
12	7,423	1,329	1,252	1,590	(1,477)	10,117
13	7,423	1,355	1,085	1,377	(1,716)	9,524
14	7,423	1,382	922	1,171	(1,884)	9,014
15	7,423	1,410	763	969	(2,002)	8,563
16	7,423	1,438	607	770	(2,084)	8,154
17	7,423	1,467	452	574	(2,142)	7,773
18	7,423	1,496	298	379	(2,183)	7,413
19	7,423	1,526	145	185	(2,212)	7,067
20	7,423	1,557	(7)	(9)	(2,232)	6,732
21	2,696	1,588	2,877	3,652	387	11,200
22	5,377	1,619	2,778	3,526	671	13,972
23	5,377	1,652	2,605	3,307	486	13,427
24	5,377	1,685	2,438	3,095	315	12,909
25	5,377	1,719	2,275	2,888	158	12,416
26	5,377	1,753	2,116	2,687	13	11,946
27	5,377	1,788	1,962	2,490	(120)	11,497
28	5,377	1,824	1,811	2,299	(242)	11,068
29	5,377	1,860	1,663	2,111	(355)	10,657
30	5,377	1,897	1,518	1,928	(459)	10,262
31	5,951	1,935	1,622	2,059	(524)	11,043
32	6,369	1,974	1,469	1,865	(756)	10,921
33	6,369	2,014	1,307	1,659	(852)	10,496
34	6,369	2,054	1,148	1,457	(941)	10,086
35	6,369	2,095	990	1,257	(1,022)	9,690
36	6,369	2,137	836	1,061	(1,097)	9,305

37	6,369	2,180	683	867	(1,166)	8,932
38	6,369	2,223	532	675	(1,230)	8,569
39	6,369	2,268	382	486	(1,288)	8,217
40	6,369	2,313	235	298	(1,342)	7,873
41	2,696	2,359	2,877	3,652	387	11,971
42	5,377	2,406	2,778	3,526	671	14,759
43	5,377	2,455	2,605	3,307	486	14,230
44	5,377	2,504	2,438	3,095	315	13,728
45	5,377	2,554	2,275	2,888	158	13,252
46	5,377	2,605	2,116	2,687	13	12,798
47	5,377	2,657	1,962	2,490	(120)	12,366
48	5,377	2,710	1,811	2,299	(242)	11,954
49	5,377	2,764	1,663	2,111	(355)	11,561
50	5,377	2,820	1,518	1,928	(459)	11,184
Total	**250,671**	**64,540**	**59,997**	**76,168**	**(12,810)**	**438,565**
PV Cost	**91,998**	**21,262**	**26,270**	**33,350**	**6,745**	**179,625**

SCHEDULE 2
Portfolio Annual Cashflow Models

SCHEDULE 2 – TABLE 1 Portfolio 1 Annual Cashflows ($ x 1,000)								
Study Year	**Pro-Energy**	**CT**	**4-Hour BESS**	**BESS Charging Energy Cost (3 months)**	**BESS Load Following Value (9 months)**	**BESS Spinning Reserve Value (9 months)**	**BESS Energy Arbitrage Value (9 months)**	**Total**
Nameplate (MW):	100	50	4	-	*4*	*0*	*0*	154
ELCC (MW):	75	38	3	*3*	-	-	-	116
1	46,370	33,040	1,295	185	(379)	0	0	81,262
2	49,416	35,449	1,729	189	(387)	0	0	87,219
3	48,299	34,597	1,453	193	(395)	0	0	84,945
4	47,206	33,771	1,252	197	(402)	0	0	82,797
5	45,968	32,887	1,105	201	(411)	0	0	80,502
6	44,457	31,879	996	205	(419)	0	0	77,847
7	44,180	31,499	912	209	(427)	0	0	77,081
8	43,697	31,027	847	213	(436)	0	0	76,037
9	43,427	30,671	795	217	(444)	0	0	75,335
10	42,912	30,201	752	222	(453)	0	0	74,285
11	42,475	29,779	841	226	(462)	0	0	73,491
12	42,201	29,446	809	231	(472)	0	0	72,831
13	41,908	29,110	762	235	(481)	0	0	72,133
14	41,689	28,818	721	240	(491)	0	0	71,561
15	41,503	28,549	685	245	(500)	0	0	71,049
16	41,331	28,292	652	250	(510)	0	0	70,567
17	41,153	28,038	622	255	(521)	0	0	70,084
18	41,005	27,803	593	260	(531)	0	0	69,653
19	40,941	27,615	565	265	(542)	0	0	69,354
20	40,956	27,470	539	270	(553)	0	0	69,177
21	41,072	27,380	896	276	(564)	0	0	69,541
22	41,064	27,232	1,118	281	(575)	0	0	69,589
23	41,099	27,108	1,074	287	(586)	0	0	69,436
24	41,123	26,982	1,033	292	(598)	0	0	69,275
25	41,173	26,872	993	298	(610)	0	0	69,156
26	41,302	26,803	956	304	(622)	0	0	69,160
27	41,459	26,752	920	310	(635)	0	0	69,212
28	41,645	26,717	885	317	(647)	0	0	69,310
29	41,860	26,699	853	323	(660)	0	0	69,455

30	42,103	26,698	821	329	(674)	0	0	69,647
31	42,376	26,712	883	336	(687)	0	0	69,979
32	42,678	26,744	874	343	(701)	0	0	70,284
33	43,010	26,792	840	349	(715)	0	0	70,612
34	43,372	26,857	807	356	(729)	0	0	70,987
35	43,765	26,938	775	364	(744)	0	0	71,411
36	44,189	27,037	744	371	(758)	0	0	71,884
37	44,645	27,153	715	378	(774)	0	0	72,407
38	45,133	27,287	686	386	(789)	0	0	72,981
39	45,654	27,438	657	394	(805)	0	0	73,606
40	46,209	27,608	630	401	(821)	0	0	74,284
41	46,799	27,796	958	409	(837)	0	0	75,370
42	47,424	28,003	1,181	418	(854)	0	0	76,406
43	48,085	28,229	1,138	426	(871)	0	0	77,231
44	48,783	28,474	1,098	435	(889)	0	0	78,115
45	49,519	28,740	1,060	443	(906)	0	0	79,059
46	50,295	29,026	1,024	452	(925)	0	0	80,065
47	51,110	29,334	989	461	(943)	0	0	81,133
48	51,967	29,663	956	470	(962)	0	0	82,266
49	52,866	30,014	925	480	(981)	0	0	83,464
50	53,809	30,388	895	489	(1,001)	0	0	84,730
Residual Value	-	-	(3,755)	-	-	-	-	(3,755)
Total	**2,226,685**	**1,439,418**	**41,555**	**15,684**	**(32,078)**	**0**	**0**	**3,691,264**
PV Cost	**634,765**	**436,065**	**13,991**	**3,538**	**(7,237)**	**0**	**0**	**1,081,122**

SCHEDULE 2 – TABLE 2 Portfolio 2 Annual Cashflows ($ x 1,000)								
Study Year	**Pro-Energy**	**RICE**	**4-Hour BESS**	**BESS Charging Energy Cost (3 months)**	**BESS Load Following Value (9 months)**	**BESS Spinning Reserve Value (9 months)**	**BESS Energy Arbitrage Value (9 months)**	**Total**
Nameplate (MW):	100	40	9	-	*4.7*	*4.3*	*0*	149
ELCC (MW):	75	34	6	*6*	-	-	-	115
1	46,370	20,373	2,913	371	(446)	(407)	0	69,174
2	49,416	21,885	3,890	378	(455)	(415)	0	74,700
3	48,299	21,351	3,268	386	(464)	(424)	0	72,418
4	47,206	20,835	2,818	394	(473)	(432)	0	70,347
5	45,968	20,287	2,487	401	(482)	(441)	0	68,220
6	44,457	19,668	2,241	409	(492)	(450)	0	65,834
7	44,180	19,414	2,053	418	(502)	(459)	0	65,104
8	43,697	19,108	1,907	426	(512)	(468)	0	64,158
9	43,427	18,871	1,789	435	(522)	(477)	0	63,522
10	42,912	18,569	1,692	443	(533)	(487)	0	62,597
11	42,475	18,296	1,892	452	(543)	(496)	0	62,075
12	42,201	18,075	1,821	461	(554)	(506)	0	61,498
13	41,908	17,854	1,714	470	(565)	(516)	0	60,865
14	41,689	17,659	1,623	480	(576)	(527)	0	60,347
15	41,503	17,477	1,541	489	(588)	(537)	0	59,886
16	41,331	17,304	1,468	499	(600)	(548)	0	59,454
17	41,153	17,133	1,399	509	(612)	(559)	0	59,023
18	41,005	16,973	1,334	519	(624)	(570)	0	58,638
19	40,941	16,842	1,272	530	(636)	(582)	0	58,366
20	40,956	16,735	1,212	540	(649)	(593)	0	58,200
21	41,072	16,661	2,016	551	(662)	(605)	0	59,032
22	41,064	16,554	2,515	562	(675)	(617)	0	59,403
23	41,099	16,461	2,417	573	(689)	(630)	0	59,231
24	41,123	16,367	2,324	585	(703)	(642)	0	59,054
25	41,173	16,283	2,235	597	(717)	(655)	0	58,915
26	41,302	16,223	2,150	608	(731)	(668)	0	58,885
27	41,459	16,174	2,070	621	(746)	(681)	0	58,896
28	41,645	16,134	1,992	633	(761)	(695)	0	58,949
29	41,860	16,104	1,918	646	(776)	(709)	0	59,043
30	42,103	16,084	1,847	659	(791)	(723)	0	59,179
31	42,376	16,074	1,988	672	(807)	(738)	0	59,565
32	42,678	16,073	1,966	685	(823)	(752)	0	59,827

33	43,010	16,083	1,889	699	(840)	(767)	0	60,074
34	43,372	16,102	1,816	713	(857)	(783)	0	60,363
35	43,765	16,131	1,744	727	(874)	(798)	0	60,695
36	44,189	16,170	1,675	742	(891)	(814)	0	61,070
37	44,645	16,219	1,608	757	(909)	(831)	0	61,489
38	45,133	16,279	1,543	772	(927)	(847)	0	61,951
39	45,654	16,348	1,479	787	(946)	(864)	0	62,459
40	46,209	16,429	1,417	803	(965)	(882)	0	63,012
41	46,799	16,520	2,155	819	(984)	(899)	0	64,410
42	47,424	16,622	2,657	835	(1,004)	(917)	0	65,617
43	48,085	16,736	2,561	852	(1,024)	(936)	0	66,275
44	48,783	16,860	2,471	869	(1,044)	(954)	0	66,985
45	49,519	16,997	2,385	886	(1,065)	(973)	0	67,750
46	50,295	17,145	2,304	904	(1,086)	(993)	0	68,569
47	51,110	17,306	2,226	922	(1,108)	(1,013)	0	69,444
48	51,967	17,479	2,152	941	(1,130)	(1,033)	0	70,376
49	52,866	17,665	2,081	959	(1,153)	(1,054)	0	71,366
50	53,809	17,865	2,013	979	(1,176)	(1,075)	0	72,415
Residual Value	-	-	(8,448)	-	-	-	-	(8,448)
Total	**2,226,685**	**870,859**	**93,498**	**31,367**	**(37,692)**	**(34,444)**	**0**	**3,150,274**
PV Cost	**634,765**	**266,960**	**31,480**	**7,077**	**(8,503)**	**(7,771)**	**0**	**924,008**

SCHEDULE 2 – TABLE 3 Portfolio 3 Annual Cashflows ($ x 1,000)							
Study Year	**ProEnergy**	**4-Hour BESS**	**BESS Charging Energy Cost (3 months)**	**BESS Load Following Value (9 months)**	**BESS Spinning Reserve Value (9 months)**	**BESS Energy Arbitrage Value (9 months)**	**Total**
Nameplate (MW):	100	85	-	*4.7*	*7.8*	*72.5*	185
ELCC (MW):	75	40	*40*	-	-	-	115
1	46,370	27,514	2,472	(446)	(739)	(1,058)	74,113
2	49,416	36,740	2,522	(455)	(753)	(1,080)	86,390
3	48,299	30,866	2,572	(464)	(769)	(1,101)	79,405
4	47,206	26,612	2,624	(473)	(784)	(1,123)	74,061
5	45,968	23,490	2,676	(482)	(800)	(1,146)	69,707
6	44,457	21,162	2,730	(492)	(816)	(1,169)	65,873
7	44,180	19,390	2,784	(502)	(832)	(1,192)	63,828
8	43,697	18,007	2,840	(512)	(849)	(1,216)	61,968
9	43,427	16,896	2,897	(522)	(866)	(1,240)	60,593
10	42,912	15,977	2,955	(533)	(883)	(1,265)	59,164
11	42,475	17,870	3,014	(543)	(900)	(1,290)	60,625
12	42,201	17,199	3,074	(554)	(918)	(1,316)	59,686
13	41,908	16,191	3,136	(565)	(937)	(1,342)	58,390
14	41,689	15,324	3,198	(576)	(956)	(1,369)	57,310
15	41,503	14,558	3,262	(588)	(975)	(1,397)	56,364
16	41,331	13,861	3,328	(600)	(994)	(1,425)	55,501
17	41,153	13,214	3,394	(612)	(1,014)	(1,453)	54,682
18	41,005	12,602	3,462	(624)	(1,034)	(1,482)	53,928
19	40,941	12,014	3,531	(636)	(1,055)	(1,512)	53,283
20	40,956	11,444	3,602	(649)	(1,076)	(1,542)	52,734
21	41,072	19,039	3,674	(662)	(1,098)	(1,573)	60,452
22	41,064	23,752	3,747	(675)	(1,120)	(1,604)	65,165
23	41,099	22,826	3,822	(689)	(1,142)	(1,636)	64,280
24	41,123	21,946	3,899	(703)	(1,165)	(1,669)	63,431
25	41,173	21,108	3,977	(717)	(1,188)	(1,702)	62,650
26	41,302	20,309	4,056	(731)	(1,212)	(1,736)	61,987
27	41,459	19,546	4,137	(746)	(1,236)	(1,771)	61,389
28	41,645	18,816	4,220	(761)	(1,261)	(1,807)	60,853
29	41,860	18,117	4,305	(776)	(1,286)	(1,843)	60,376
30	42,103	17,446	4,391	(791)	(1,312)	(1,880)	59,957
31	42,376	18,774	4,478	(807)	(1,338)	(1,917)	61,566
32	42,678	18,566	4,568	(823)	(1,365)	(1,956)	61,668

33	43,010	17,844	4,659	(840)	(1,392)	(1,995)	61,287
34	43,372	17,147	4,753	(857)	(1,420)	(2,035)	60,961
35	43,765	16,472	4,848	(874)	(1,448)	(2,075)	60,688
36	44,189	15,819	4,945	(891)	(1,477)	(2,117)	60,467
37	44,645	15,184	5,043	(909)	(1,507)	(2,159)	60,298
38	45,133	14,568	5,144	(927)	(1,537)	(2,202)	60,179
39	45,654	13,968	5,247	(946)	(1,568)	(2,246)	60,110
40	46,209	13,384	5,352	(965)	(1,599)	(2,291)	60,091
41	46,799	20,351	5,459	(984)	(1,631)	(2,337)	67,657
42	47,424	25,090	5,568	(1,004)	(1,664)	(2,384)	73,031
43	48,085	24,191	5,680	(1,024)	(1,697)	(2,432)	72,803
44	48,783	23,338	5,793	(1,044)	(1,731)	(2,480)	72,659
45	49,519	22,528	5,909	(1,065)	(1,766)	(2,530)	72,596
46	50,295	21,757	6,027	(1,086)	(1,801)	(2,580)	72,612
47	51,110	21,023	6,148	(1,108)	(1,837)	(2,632)	72,704
48	51,967	20,322	6,271	(1,130)	(1,874)	(2,685)	72,872
49	52,866	19,653	6,396	(1,153)	(1,911)	(2,738)	73,114
50	53,809	19,013	6,524	(1,176)	(1,949)	(2,793)	73,428
Residual Value	-	(79,791)	-	-	-	-	(79,791)
Total	**2,226,685**	**883,035**	**209,116**	**(37,692)**	**(62,480)**	**(89,523)**	**3,129,142**
PV Cost	**634,765**	**297,311**	**47,178**	**(8,503)**	**(14,096)**	**(20,197)**	**936,457**

SCHEDULE 2 – TABLE 4 Portfolio 4 Annual Cashflows ($ x 1,000)							
Study Year	**CT**	**4-Hour BESS**	**BESS Charging Energy Cost (3 months)**	**BESS Load Following Value (9 months)**	**BESS Spinning Reserve Value (9 months)**	**BESS Energy Arbitrage Value (9 months)**	**Total**
Nameplate (MW):	50	300	-	*4.7*	*7.8*	*287.5*	350
ELCC (MW):	38	77	*77*	-	-	-	115
1	33,040	97,107	4,759	(446)	(739)	(4,197)	129,524
2	35,449	129,671	4,855	(455)	(753)	(4,281)	164,485
3	34,597	108,941	4,952	(464)	(769)	(4,367)	142,891
4	33,771	93,923	5,051	(473)	(784)	(4,454)	127,035
5	32,887	82,906	5,152	(482)	(800)	(4,543)	115,120
6	31,879	74,690	5,255	(492)	(816)	(4,634)	105,882
7	31,499	68,435	5,360	(502)	(832)	(4,727)	99,233
8	31,027	63,553	5,467	(512)	(849)	(4,821)	93,865
9	30,671	59,635	5,576	(522)	(866)	(4,918)	89,576
10	30,201	56,391	5,688	(533)	(883)	(5,016)	85,848
11	29,779	63,070	5,802	(543)	(900)	(5,116)	92,090
12	29,446	60,702	5,918	(554)	(918)	(5,219)	89,374
13	29,110	57,143	6,036	(565)	(937)	(5,323)	85,464
14	28,818	54,086	6,157	(576)	(956)	(5,430)	82,099
15	28,549	51,380	6,280	(588)	(975)	(5,538)	79,108
16	28,292	48,922	6,406	(600)	(994)	(5,649)	76,376
17	28,038	46,637	6,534	(612)	(1,014)	(5,762)	73,821
18	27,803	44,476	6,664	(624)	(1,034)	(5,877)	71,408
19	27,615	42,402	6,798	(636)	(1,055)	(5,995)	69,129
20	27,470	40,390	6,934	(649)	(1,076)	(6,115)	66,954
21	27,380	67,198	7,072	(662)	(1,098)	(6,237)	93,654
22	27,232	83,832	7,214	(675)	(1,120)	(6,362)	110,121
23	27,108	80,563	7,358	(689)	(1,142)	(6,489)	106,709
24	26,982	77,456	7,505	(703)	(1,165)	(6,619)	103,457
25	26,872	74,498	7,655	(717)	(1,188)	(6,751)	100,369
26	26,803	71,678	7,808	(731)	(1,212)	(6,886)	97,460
27	26,752	68,985	7,964	(746)	(1,236)	(7,024)	94,695
28	26,717	66,408	8,124	(761)	(1,261)	(7,164)	92,064
29	26,699	63,941	8,286	(776)	(1,286)	(7,308)	89,557
30	26,698	61,573	8,452	(791)	(1,312)	(7,454)	87,165
31	26,712	66,260	8,621	(807)	(1,338)	(7,603)	91,846
32	26,744	65,526	8,793	(823)	(1,365)	(7,755)	91,120

33	26,792	62,979	8,969	(840)	(1,392)	(7,910)	88,598
34	26,857	60,518	9,149	(857)	(1,420)	(8,068)	86,179
35	26,938	58,137	9,332	(874)	(1,448)	(8,230)	83,856
36	27,037	55,830	9,518	(891)	(1,477)	(8,394)	81,623
37	27,153	53,592	9,709	(909)	(1,507)	(8,562)	79,476
38	27,287	51,417	9,903	(927)	(1,537)	(8,733)	77,409
39	27,438	49,300	10,101	(946)	(1,568)	(8,908)	75,418
40	27,608	47,239	10,303	(965)	(1,599)	(9,086)	73,500
41	27,796	71,827	10,509	(984)	(1,631)	(9,268)	98,249
42	28,003	88,554	10,719	(1,004)	(1,664)	(9,453)	115,155
43	28,229	85,379	10,934	(1,024)	(1,697)	(9,642)	112,179
44	28,474	82,369	11,152	(1,044)	(1,731)	(9,835)	109,385
45	28,740	79,509	11,375	(1,065)	(1,766)	(10,032)	106,762
46	29,026	76,789	11,603	(1,086)	(1,801)	(10,232)	104,299
47	29,334	74,198	11,835	(1,108)	(1,837)	(10,437)	101,985
48	29,663	71,726	12,072	(1,130)	(1,874)	(10,646)	99,811
49	30,014	69,365	12,313	(1,153)	(1,911)	(10,859)	97,769
50	30,388	67,105	12,559	(1,176)	(1,949)	(11,076)	95,851
Residual Value	-	(281,616)	-	-	-	-	(281,616)
Total	**1,439,418**	**3,116,594**	**402,548**	**(37,692)**	**(62,480)**	**(355,004)**	**4,503,385**
PV Cost	**436,065**	**1,049,332**	**90,817**	**(8,503)**	**(14,096)**	**(80,091)**	**1,473,524**

SCHEDULE 2 – TABLE 5 Portfolio 5 Annual Cashflows ($ x 1,000)						
Study Year	**4-Hour BESS**	**BESS Charging Energy Cost (3 months)**	**BESS Load Following Value (9 months)**	**BESS Spinning Reserve Value (9 months)**	**BESS Energy Arbitrage Value (9 months)**	**Total**
Nameplate (MW):	540	-	*4.7*	*7.8*	*527.5*	540
ELCC (MW):	115	*115*	-	-	-	115
1	174,792	7,108	(446)	(739)	(7,701)	173,015
2	233,407	7,250	(455)	(753)	(7,855)	231,594
3	196,093	7,395	(464)	(769)	(8,012)	194,244
4	169,062	7,543	(473)	(784)	(8,172)	167,176
5	149,231	7,694	(482)	(800)	(8,336)	147,307
6	134,441	7,848	(492)	(816)	(8,503)	132,479
7	123,182	8,005	(502)	(832)	(8,673)	121,181
8	114,396	8,165	(512)	(849)	(8,846)	112,354
9	107,342	8,328	(522)	(866)	(9,023)	105,260
10	101,503	8,495	(533)	(883)	(9,204)	99,379
11	113,526	8,665	(543)	(900)	(9,388)	111,360
12	109,264	8,838	(554)	(918)	(9,575)	107,054
13	102,858	9,015	(565)	(937)	(9,767)	100,604
14	97,354	9,195	(576)	(956)	(9,962)	95,055
15	92,484	9,379	(588)	(975)	(10,161)	90,139
16	88,059	9,567	(600)	(994)	(10,365)	85,667
17	83,947	9,758	(612)	(1,014)	(10,572)	81,508
18	80,057	9,953	(624)	(1,034)	(10,783)	77,569
19	76,324	10,152	(636)	(1,055)	(10,999)	73,786
20	72,703	10,355	(649)	(1,076)	(11,219)	70,114
21	120,957	10,562	(662)	(1,098)	(11,443)	118,316
22	150,897	10,774	(675)	(1,120)	(11,672)	148,203
23	145,013	10,989	(689)	(1,142)	(11,906)	142,266
24	139,421	11,209	(703)	(1,165)	(12,144)	136,618
25	134,097	11,433	(717)	(1,188)	(12,387)	131,238
26	129,020	11,662	(731)	(1,212)	(12,634)	126,104
27	124,172	11,895	(746)	(1,236)	(12,887)	121,198
28	119,535	12,133	(761)	(1,261)	(13,145)	116,502
29	115,093	12,376	(776)	(1,286)	(13,408)	111,999
30	110,831	12,623	(791)	(1,312)	(13,676)	107,675
31	119,268	12,876	(807)	(1,338)	(13,949)	116,049
32	117,946	13,133	(823)	(1,365)	(14,228)	114,662

33	113,362	13,396	(840)	(1,392)	(14,513)	110,013
34	108,933	13,664	(857)	(1,420)	(14,803)	105,517
35	104,647	13,937	(874)	(1,448)	(15,099)	101,163
36	100,495	14,216	(891)	(1,477)	(15,401)	96,940
37	96,465	14,500	(909)	(1,507)	(15,709)	92,840
38	92,550	14,790	(927)	(1,537)	(16,024)	88,852
39	88,741	15,086	(946)	(1,568)	(16,344)	84,969
40	85,030	15,387	(965)	(1,599)	(16,671)	81,183
41	129,289	15,695	(984)	(1,631)	(17,004)	125,365
42	159,396	16,009	(1,004)	(1,664)	(17,344)	155,394
43	153,683	16,329	(1,024)	(1,697)	(17,691)	149,600
44	148,264	16,656	(1,044)	(1,731)	(18,045)	144,099
45	143,116	16,989	(1,065)	(1,766)	(18,406)	138,869
46	138,220	17,329	(1,086)	(1,801)	(18,774)	133,888
47	133,556	17,675	(1,108)	(1,837)	(19,150)	129,137
48	129,107	18,029	(1,130)	(1,874)	(19,533)	124,599
49	124,856	18,389	(1,153)	(1,911)	(19,923)	120,258
50	120,790	18,757	(1,176)	(1,949)	(20,322)	116,100
Residual Value	(597,143)	-	-	-	-	(597,143)
Total	**5,519,636**	**601,209**	**(37,692)**	**(62,480)**	**(651,355)**	**5,369,317**
PV Cost	**1,885,472**	**135,636**	**(8,503)**	**(14,096)**	**(146,949)**	**1,851,560**

SCHEDULE 3
8-Hour BESS Portfolios 6 Through 10 Inputs and Results

SCHEDULE 3 – TABLE 1 Portfolio NPV Study Portfolios 6 through 10 (MW)					
	Portfolio 6	**Portfolio 7**	**Portfolio 8**	**Portfolio 9**	**Portfolio 10**
ProEnergy Opportunity	2 x 50	2 x 50	2 x 50	-	-
Combustion Turbine	1 x 50	-	-	1 x 50	-
RICE plant	-	2 x 20	-	-	-
8-hour BESS[58]	4	7	50	180	390
Total nameplate capacity	**154**	**147**	**150**	**230**	**390**
ELCC	**115**	**115**	**115**	**115**	**115**

[58] In the Portfolio NPV Study, the cost of a BESS was modelled based on a 50 MW project to align with previous cost estimates and account for economies of scale. The total cost of the BESS capacity was scaled accordingly based on the total BESS capacity in each portfolio.

SCHEDULE 3 – TABLE 2 50 MW 8-Hour BESS Inputs		
Input	**Value**	**Reference**
Useful life (years)	20	Consistent with previous Maritime Electric and Synapse NPV analyses.
Total installed cost ($'000)	200,724	Consistent with the Synapse Report, the cost of a 4-hour BESS was multiplied by a factor of 1.72 to estimate the cost of an 8-hour BESS, based on the referenced NREL report: https://docs.nlr.gov/docs/fy25osti/93281.pdf.
Augmentation cost at year 11 ($'000)	14,371	Consistent with the Synapse Report, the cost of a 4-hour BESS was multiplied by a factor of 1.72 to estimate the cost of an 8-hour BESS, based on the referenced NREL report: https://docs.nlr.gov/docs/fy25osti/93281.pdf.
Year-1 operation and maintenance cost ($'000)	1,838	Consistent with the Synapse Report, the cost of a 4-hour BESS was multiplied by a factor of 1.72 to estimate the cost of an 8-hour BESS, based on the referenced NREL report: https://docs.nlr.gov/docs/fy25osti/93281.pdf.
Roundtrip efficiency	85%	NREL report referenced by Synapse.[59]
Winter charging energy price ($/MWh)	196	Refer to Section 4.7.1.
Load following rate ($/MW-month)	10,535	Exhibit M-1, Table 11 (page 50).
Spinning reserve rate ($/MW-month)	10,523	Exhibit M-1, Table 11 (page 50).
Year- 4-hour BESS March to November energy arbitrage value per MW ($/MW)	29,198	Refer to Section 4.9. The energy arbitrage for the 8-hour BESS is double the 4-hour BESS due to having double the storage capacity.
Replacement BESS (at year 21 and year 41) cost portion of initial BESS cost	84%	Refer to Section 2.5. NREL report referenced by Synapse.[60]

SCHEDULE 3 – TABLE 3 Base Case Portfolio Present Value Cost Comparison ($ millions)					
	Portfolio 1	**Portfolio 2**	**Portfolio 3**	**Portfolio 4**	**Portfolio 5**
Total (refer to Section 5.0)	1,081	924	936	1,474	1,852
	Portfolio 6	**Portfolio 7**	**Portfolio 8**	**Portfolio 9**	**Portfolio 10**
100 MW ProEnergy	635	635	635	-	-
50 MW CT	436	-	-	436	-
40 MW RICE plant	-	267	-	-	-
8-Hour BESS	20	36	301	1,052	-
Total	**1,091**	**938**	**936**	**1,488**	**2,230**
Difference	10	14	0	15	378

[59] Cole, Wesley, Vignesh Ramasamy, and Merve Turan. 2025. Cost Projections for Utility-Scale Battery Storage: 2025 Update. National Renewable Energy Laboratory (page 12).

[60] Ibid. 84% derived from Figure 1 (page 6).

SCHEDULE 4
Thermal Units Fuel Cost Rate Forecast

SCHEDULE 4 – TABLE 1 Thermal Units Fuel Cost Rate Forecast (Base Case)				
	Annual Escalation		CT Fuel Cost Rate ($/MWh)	RICE Fuel Cost Rate ($/MWh)
Project Year	EIA forecast[61]	Projection[62]		
1	-	-	454	328
2	0.993	-	444	320
3	0.977	-	445	321
4	0.975	-	449	324
5	0.958	-	456	329
6	0.931	-	463	334
7	1.036	-	485	350
8	1.012	-	502	362
9	1.026	-	515	371
10	1.002	-	528	381
11	1.005	-	540	389
12	1.015	-	553	399
13	1.010	-	568	410
14	1.013	-	583	421
15	1.013	-	598	432
16	1.011	-	616	445
17	1.009	-	631	455
18	1.009	-	652	471
19	1.012	-	669	483
20	1.015	-	684	494
21	1.019	-	707	510
22	1.010	-	737	532
23	1.011	-	752	543
24	1.009	-	768	555
25	1.009	-	786	568
26	-	1.011	808	583
27	-	1.011	831	600
28	-	1.011	854	616
29	-	1.011	878	633
30	-	1.011	902	651

[61] United States Energy Information Administration. Annual Energy Outlook 2026. Table 3: Energy Prices by Sector and Source, United States counterfactual baseline case.

[62] Projection based on 10-year average EIA escalation forecast from Project Year 16 to 25 (inclusive).

31	-	1.011	927	669
32	-	1.011	953	688
33	-	1.011	979	707
34	-	1.011	1,007	727
35	-	1.011	1,035	747
36	-	1.011	1,063	768
37	-	1.011	1,093	789
38	-	1.011	1,123	811
39	-	1.011	1,155	833
40	-	1.011	1,187	857
41	-	1.011	1,220	880
42	-	1.011	1,254	905
43	-	1.011	1,289	930
44	-	1.011	1,325	956
45	-	1.011	1,361	983
46	-	1.011	1,399	1,010
47	-	1.011	1,438	1,038
48	-	1.011	1,478	1,067
49	-	1.011	1,519	1,097
50	-	1.011	1,562	1,127

SCHEDULE 5
ISO-NE Internal Hub 2025 Locational Marginal Pricing On- and Off-Peak Price Differential

SCHEDULE 5 – TABLE 1
ISO-NE Internal Hub 2025 Day-Ahead Hourly LMP On- and Off-Peak Price Differential ($US)
(on-peak = HE18-23; off-peak = HE 24, HE1-17; days >$US 20 shown in green)

Day of Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	9.83	69.41	13.19	19.08	11.91	12.14	19.61	7.44	15.46	8.17	2.03	33.27
2	15.20	23.60	45.63	11.36	19.00	14.89	22.65	22.10	15.11	17.52	26.87	7.75
3	18.10	-3.44	30.86	-5.67	16.86	20.62	25.11	23.55	13.40	11.34	1.90	28.72
4	31.22	49.36	-23.62	4.07	14.09	22.14	21.17	39.01	9.31	30.61	9.53	30.49
5	25.81	34.69	-11.45	3.11	4.02	29.54	32.13	8.50	15.70	39.38	16.87	41.90
6	37.22	-22.56	5.11	0.52	9.83	-0.57	97.35	7.52	12.86	36.87	33.14	-12.39
7	1.14	30.92	12.02	15.58	15.48	-0.51	91.11	20.85	-4.63	35.12	9.15	40.20
8	30.80	29.26	16.66	14.21	16.65	17.98	81.51	23.94	16.76	-5.29	0.96	83.84
9	6.19	20.72	15.75	16.20	4.27	8.12	8.94	22.18	12.21	12.17	2.84	28.29
10	14.11	33.68	12.64	18.43	7.51	-0.15	3.40	46.03	7.03	11.93	2.72	-34.74
11	6.80	-1.12	6.04	7.64	28.39	17.68	29.27	118.92	11.95	15.80	18.46	57.77
12	15.99	-1.17	19.53	2.33	28.07	14.73	25.80	97.55	15.11	5.90	3.66	27.13
13	20.94	-11.79	10.52	-0.71	15.82	12.00	32.23	35.39	12.03	4.59	5.13	25.44
14	36.55	30.17	6.90	13.73	14.11	1.11	28.05	6.29	21.98	4.43	13.72	13.81
15	47.99	27.00	5.17	10.18	15.38	18.06	99.94	23.64	12.91	6.97	12.97	39.18
16	19.06	2.11	12.53	12.62	16.16	11.77	149.39	9.40	11.28	9.68	-2.84	17.47
17	-4.94	42.82	2.75	17.88	16.13	-0.59	59.37	38.03	11.85	14.14	19.08	-21.40
18	-11.78	35.71	10.76	12.77	12.90	20.40	-2.39	22.28	14.79	15.51	33.62	-0.39
19	55.71	26.70	6.01	18.07	14.87	25.25	28.87	23.63	10.76	19.16	27.30	-1.61
20	51.62	9.30	5.83	21.94	10.70	6.19	24.33	5.12	17.69	3.46	26.68	29.08
21	41.86	11.07	2.91	18.82	7.76	21.64	13.30	16.85	16.16	32.15	-3.20	20.27
22	27.93	9.78	11.54	7.45	2.75	22.55	27.10	20.86	18.03	12.13	-10.16	30.65
23	-0.21	18.05	14.84	11.44	6.49	120.50	33.60	11.24	25.73	13.49	14.65	-1.87
24	5.76	11.94	2.46	17.52	11.78	211.47	112.61	16.24	13.68	10.84	15.11	16.59
25	8.31	13.88	10.83	14.18	12.82	51.16	89.72	12.97	5.31	12.36	4.54	-24.61
26	29.72	10.89	11.21	9.80	18.29	-15.62	18.76	13.78	18.00	27.09	4.11	54.27
27	26.83	-7.50	15.57	10.77	18.04	-0.77	10.65	10.31	20.12	16.74	1.47	-14.65
28	65.31	16.62	7.82	23.70	14.45	20.47	130.89	7.68	23.30	11.31	16.54	1.43
29	4.36	-	8.77	17.50	5.83	24.63	175.10	4.85	22.23	13.31	42.30	-15.28
30	31.06	-	15.25	17.71	11.10	50.04	100.82	10.61	7.15	0.30	-0.65	54.29
31	-13.58	-	0.54	-	-1.39	-	-8.80	19.05	-	1.14	-	33.68
No. of days >20:			**2**	**2**	**2**	**13**	**23**	**15**	**5**	**6**	**6**	

IR-55(b) – Attachment 1

S&L Update Letter

Terrence Coyne, P.E.
Senior Project Manager – Consulting Services
1-312-269-3642
terrence.p.coyne@sargentlundy.com

July 22, 2026

Re: Estimated Lead Times and Capital Cost Estimates – On-Island Capacity Application

Adam MacKenzie, P. Eng.
Planning Engineer
Maritime Electric Company Ltd.

Dear Mr. MacKenzie:

Sargent & Lundy (S&L) is providing this letter to Maritime Electric Company Ltd. (MECL) in response to requests made during the interrogatory process for the On-Island Capacity Application. Specifically, this letter documents updated expected lead times / commercial operation dates and capital cost estimates for on-island generation alternatives: the GE LM6000 PC combustion turbine (CT) and the Wärtsilä 5 x 18V50 reciprocating internal combustion engine (RICE) configuration.

The following lead time and commercial operation date (COD) estimates are based on current market conditions and S&L's experience with ongoing procurements. All dates assume project initiation (notice to proceed) in Q3 2026.

Estimated Equipment Lead Times

Milestone	GE LM6000 PC (Single Unit)	Wärtsilä 5×18V50
Expected Equipment Delivery	Q1 2031	Q2/Q3 2029
Estimated Delivery-to-COD Period	6 months	12 months
Estimated Commercial Operation Date	Q3 2031	Q2/Q3 2030

The table that follows presents updated overnight capital cost (OCC) estimates for the primary on-island generation alternatives, in Canadian dollars. OCC estimates fundamentally assume that the project is built “overnight” and are a common way to present costs in the energy industry as they allow for projects with different construction timelines to be compared head-to-head. OCCs do not include cost considerations such as escalation, financing fees, interest

during construction (IDC), tariffs, land acquisition, network upgrades or interconnection facility costs, or HV transmission line. As a result, overnight capital costs should not be compared directly with prices being seen in the marketplace, due to differences in escalation, IDC, and other factors. These estimates reflect current (Q3 2026) market conditions and are estimated based on a turnkey engineering, procurement, and construction (EPC) basis.

Estimated Overnight Capital Cost Comparison ($CAD)

Parameter	GE LM6000 PC (Single Unit)	Wärtsilä 5×18V50
Net Plant Rating (MW)	51.1 MW	91.7 MW
Total Plant Installed OCC (CAD)	$275,000,000	$395,000,000
OCC per kW (CAD/kW)	$5,381	$4,308

Notes:

1) *Estimates reflect an Association for the Advancement of Cost Engineering (AACE) International Class 5 accuracy classification (conceptual/screening estimate). AACE Class 5 accuracy range: Low: −20% to −50%; High: +30% to +100%.*
2) *Overnight capital cost estimates are based on a USD to CAD conversion ratio of 1.4.*
3) *Given the substantial lead times for the above equipment and recent price increases, MECL would likely have to pay more than the values represented in the table above for the LM6000 turbines and Wärtsilä engines.*

The current power sector market is characterized by significant volatility in equipment and construction costs, with rapid changes over relatively short time frames. As a result, OCC estimates should be viewed as indicative planning values rather than firm price expectations, and the implied “validity period” of any estimate should be assumed to be short unless explicitly stated otherwise. Any comparison to market quotations should therefore adjust for differences in scope, cost basis year, estimate class, and financing assumptions before drawing conclusions about reasonableness or competitiveness.

OCC estimates are also often influenced by owner’s cost assumptions; project owners often vary in their construction oversight and staffing strategies during construction. Project owners can have a less-involved approach, with few full-time personnel on site, or a more involved approach, with a substantial full-time presence on site. A project owner’s strategy can significantly impact owner’s costs subsequently affecting the total OCC. The owner’s cost estimates included in this letter are based on a less-involved (light) approach, representing a lean owner’s team on-site.

S&L trusts this information is helpful to MECL in supporting the on-island capacity application. Please do not hesitate to contact us if you have any questions or require any further clarification.

Best Regards,

Terrence Coyne
Senior Project Manager – Consulting Services

IR-84 – Confidential Attachment 1

Updated Estimated Impact on Customer Rates

Depreciation
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Depreciation (000s)	Reference		Annual
Depreciation Expense			
Capital Additions for 2029	A		353,372
Plant Investment for Depreciation	C = A + B	$	353,372
Depreciation Rate (Note 1)	D		2.20%
2029 Depreciation Expense (half year)	E = C X D	$	3,887
Capital Investment			
Capital Investment	A		353,372
Less: Customer Contributions per Annual Depreciation	F		-
Total Capital Investment	G = A + F	$	353,372
Accumulated Depreciation			
Accumulated Depreciation, December 31, 2029	I		3,887
Total Change in Accumulated Depreciation	J = H + I	$	3,887
Net Book Value (NBV) - Capital Investment	**K = C - J**	**$**	**349,485**
Customer Contributions			
Customer Contributions per Annual Depreciation	F	**$**	**-**
Depreciation Expense - Contributions			
Annual Contributions	F	$	-
Depreciation Rate	L		2.20%
Amortization of Customer Contributions	M = F X L	$	-
Accumulated Depreciation, December 31, 2029	N	$	-
Net Book Value (NBV) - Customer Contributions	**O = F - N**	**$**	**-**
Total 2029 Depreciation Expense (Net of Contributions)	**P = E + M**	**$**	**3,887**

Note 1: Assumed 50 year useful life 100% / 50 Years = 2%

Income Taxes
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Income Taxes (000s)	Reference		Annual
Capital Additions for 2029	A		353,372
Less: Contributions	B		-
CCA Deductions 2029	C		14,135
Ending UCC	D = A - B - C	$	339,237
Future Income Taxes			
CCA Deductions 2029	C	$	14,135
Accumulated Depreciation, December 31, 2029	E = I - N From Page 1		3,887
Difference CCA/Depreciation	F = C - E		10,248
Future Tax Rate	G		31.00%
Future Income Tax Liability	H = F X G		3,177
Income Tax Effects of Increased Return			
Return on Rate Base	I = H from Page 3	$	24,186
Equity Return (grossed up)	J = G from Page 3 / (1-G)		20,896
Taxable Income from Return on Rate Base	K = J	$	20,896
Income Tax Expense			
Taxable Income from Return on Rate Base	L	$	20,896
Add: Depreciation	M = P from Page 1		3,887
Less: CCA	N = 2029 CCA		(14,135)
	O = L + M + N		10,648
Corporate Tax Rate	G		31.00%
Current Income Tax Expense	P = O X G		3,301
Future Income Tax Expense	Q = (-M - N)* G		3,177
Total Income Tax Expense	**R = P + Q**	**$**	**6,478**

2029 Rate Base & Cost of Capital
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Rate Base & Cost of Capital (000s)	Reference		
Net Book Value, Capital Investment	A = K from Page 1	$	349,485
Net Book Value, Contributions	B = O from Page 1		-
Future Income Taxes	C = H from Page 2		(3,177)
Projected Rate Base	**D = A + B + C**	**$**	**346,308**
Total % Increase from 2025 Actual Year End Rate Base	**E = D / R**		**58.02%**
Return on Debt	F = D X O	$	9,768
Return on Common Equity	G = D X P		14,418
Total Return On Rate Base	H = F + G	$	24,186
Weighted Average Cost of Capital ("WACC")			
Debt	I		60.0%
Common Equity	J		40.0%
Cost of Debt	K		4.23%
Cost of Common Equity	L		9.35%
2025 Average Capitalization (Total Debt plus Common Equity)	M		638,765,377
2025 Average Rate Base*	N		574,368,441
WA Cost of Debt	O = I X K X M/ N		2.82%
WA Cost of Common Equity	P = J X L X M/ N		4.16%
2025 WACC	Q = O + P		6.98%
2025 Year End Rate Base	**R**	**$**	**596,902**

Revenue Requirement
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

2029 Annual Project Revenue Requirement (000s)	Reference		0
Depreciation	A = P from Page 1	$	3,887
[redacted]			
Return on Debt	C = F from Page 3		9,768
Return on Equity	D = G from Page 3		14,418
Income Taxes	E = R from Page 2		6,478
Estimated Annual Project Revenue Requirement	**F = A + B + C + D + E**	**$**	**18,771**
% Increase over 2025 Forecast Revenue Requirement	**G = F / H**		**7.36%**
2025 Revenue Requirement*	**H**	**$**	**255,063**

Total Change in Revenue Requirement Allocated to MECL	**100% = F**	**$**	**18,771**

* 2025 forecast revenue requirement per GRA Negotiated Settlement filed with the Commission on April 4, 2023.

Distribution Rate Impact
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Project Rate Impact	Reference		0
Total Project Revenue Requirement	A = F from Appendix F X 1000	$	18,771,092
Forecast 2029 kWh Sales	B		1,724,249,644
Forecast Increase Per kWh Project Rate Impact	**C = A / B**	**$**	**0.01089**
Forecast Increase Annual Cost Benchmark Residential Customer (650 kWh per month) before tax	**D = 650 kWh X C X 12 months**	**$**	**84.94**
% Increase over 2025 Forecast Annual Cost for Rural Residential Customer	E = D / I		5.18%
% Increase over 2025 Forecast Annual Cost for Urban Residential Customer	F = D / J		5.27%
Forecast Increase Annual Cost Benchmark General Service Customer (10,000 kWh per month) before tax	**G = 10,000 kWh X C X 12 months**	**$**	**1,306.80**
% Increase over 2025 Forecast Annual Cost for General Service Customer	H = G / K		5.08%
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	I	$	1,639.09
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on June 20, 2022 April 4, 2023.	J		$1,610.89
2025/2026 Annual Cost Benchmark General Service Customer (10,000 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	K	$	25,712.54

IR-84(a) – Confidential Attachment 1

Updated Estimated Impact on Customer Rates Based on a 10% Increase Bid Submission

Depreciation
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Depreciation (000s)	Reference		Annual
Depreciation Expense			
Capital Additions for 2029	A		388,709
Plant Investment for Depreciation	C = A + B	$	388,709
Depreciation Rate (Note 1)	D		2.20%
2029 Depreciation Expense (half year)	E = C X D	$	4,276
Capital Investment			
Capital Investment	A		388,709
Less: Customer Contributions per Annual Depreciation	F		-
Total Capital Investment	G = A + F	$	388,709
Accumulated Depreciation			
Accumulated Depreciation, December 31, 2029	I		4,276
Total Change in Accumulated Depreciation	J = H + I	$	4,276
Net Book Value (NBV) - Capital Investment	**K = C - J**	**$**	**384,433**
Customer Contributions			
Customer Contributions per Annual Depreciation	F	**$**	**-**
Depreciation Expense - Contributions			
Annual Contributions	F	$	-
Depreciation Rate	L		2.20%
Amortization of Customer Contributions	M = F X L	$	-
Accumulated Depreciation, December 31, 2029	N	$	-
Net Book Value (NBV) - Customer Contributions	**O = F - N**	**$**	**-**
Total 2029 Depreciation Expense (Net of Contributions)	**P = E + M**	**$**	**4,276**

Note 1: Assumed 50 year useful life 100% / 50 Years = 2%

Income Taxes
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Income Taxes (000s)	Reference		Annual
Capital Additions for 2029	A		388,709
Less: Contributions	B		-
CCA Deductions 2029	C		15,548
Ending UCC	D = A - B - C	$	373,161
Future Income Taxes			
CCA Deductions 2029	C	$	15,548
Accumulated Depreciation, December 31, 2029	E = I - N From Page 1		4,276
Difference CCA/Depreciation	F = C - E		11,273
Future Tax Rate	G		31.00%
Future Income Tax Liability	H = F X G		3,494
Income Tax Effects of Increased Return			
Return on Rate Base	I = H from Page 3	$	26,605
Equity Return (grossed up)	J = G from Page 3 / (1-G)		22,986
Taxable Income from Return on Rate Base	K = J	$	22,986
Income Tax Expense			
Taxable Income from Return on Rate Base	L	$	22,986
Add: Depreciation	M = P from Page 1		4,276
Less: CCA	N = 2029 CCA		(15,548)
	O = L + M + N		11,713
Corporate Tax Rate	G		31.00%
Current Income Tax Expense	P = O X G		3,631
Future Income Tax Expense	Q = (-M - N)* G		3,494
Total Income Tax Expense	**R = P + Q**	**$**	**7,126**

2029 Rate Base & Cost of Capital
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Rate Base & Cost of Capital (000s)	Reference		
Net Book Value, Capital Investment	A = K from Page 1	$	384,433
Net Book Value, Contributions	B = O from Page 1		-
Future Income Taxes	C = H from Page 2		(3,494)
Projected Rate Base	**D = A + B + C**	**$**	**380,939**
Total % Increase from 2025 Actual Year End Rate Base	**E = D / R**		**63.82%**
Return on Debt	F = D X O	$	10,745
Return on Common Equity	G = D X P		15,860
Total Return On Rate Base	H = F + G	$	26,605
Weighted Average Cost of Capital ("WACC")			
Debt	I		60.0%
Common Equity	J		40.0%
Cost of Debt	K		4.23%
Cost of Common Equity	L		9.35%
2025 Average Capitalization (Total Debt plus Common Equity)	M		638,765,377
2025 Average Rate Base*	N		574,368,441
WA Cost of Debt	O = I X K X M/ N		2.82%
WA Cost of Common Equity	P = J X L X M/ N		4.16%
2025 WACC	Q = O + P		6.98%
2025 Year End Rate Base	**R**	**$**	**596,902**

Revenue Requirement
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

2029 Annual Project Revenue Requirement (000s)	Reference		0
Depreciation	A = P from Page 1	$	4,276
[redacted]			
Return on Debt	C = F from Page 3		10,745
Return on Equity	D = G from Page 3		15,860
Income Taxes	E = R from Page 2		7,126
Estimated Annual Project Revenue Requirement	**F = A + B + C + D + E**	**$**	**22,227**
% Increase over 2025 Forecast Revenue Requirement	**G = F / H**		**8.71%**
2025 Revenue Requirement*	**H**	**$**	**255,063**

Total Change in Revenue Requirement Allocated to MECL	**100% = F**	**$**	**22,227**

* 2025 forecast revenue requirement per GRA Negotiated Settlement filed with the Commission on April 4, 2023.

Distribution Rate Impact
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Project Rate Impact	**Reference**		**0**
Total Project Revenue Requirement	A = F from Appendix F X 1000	$	22,226,801
Forecast 2029 kWh Sales	B		1,724,249,644
Forecast Increase Per kWh Project Rate Impact	**C = A / B**	**$**	**0.01289**
Forecast Increase Annual Cost Benchmark Residential Customer (650 kWh per month) before tax	**D = 650 kWh X C X 12 months**	**$**	**100.54**
% Increase over 2025 Forecast Annual Cost for Rural Residential Customer	E = D / I		6.13%
% Increase over 2025 Forecast Annual Cost for Urban Residential Customer	F = D / J		6.24%
Forecast Increase Annual Cost Benchmark General Service Customer (10,000 kWh per month) before tax	**G = 10,000 kWh X C X 12 months**	**$**	**1,546.80**
% Increase over 2025 Forecast Annual Cost for General Service Customer	H = G / K		6.02%
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	I	$	1,639.09
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on June 20, 2022 April 4, 2023.	J		$1,610.89
2025/2026 Annual Cost Benchmark General Service Customer (10,000 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	K	$	25,712.54

IR-84(b) – Confidential Attachment 1

Updated Estimated Impact on Customer Rates Based on a 20% Increase Bid Submission

Depreciation
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Depreciation (000s)	Reference		Annual
Depreciation Expense			
Capital Additions for 2029	A		424,046
Plant Investment for Depreciation	C = A + B	$	424,046
Depreciation Rate (Note 1)	D		2.20%
2029 Depreciation Expense (half year)	E = C X D	$	4,665
Capital Investment			
Capital Investment	A		424,046
Less: Customer Contributions per Annual Depreciation	F		-
Total Capital Investment	G = A + F	$	424,046
Accumulated Depreciation			
Accumulated Depreciation, December 31, 2029	I		4,665
Total Change in Accumulated Depreciation	J = H + I	$	4,665
Net Book Value (NBV) - Capital Investment	**K = C - J**	**$**	**419,382**
Customer Contributions			
Customer Contributions per Annual Depreciation	F	**$**	**-**
Depreciation Expense - Contributions			
Annual Contributions	F	$	-
Depreciation Rate	L		2.20%
Amortization of Customer Contributions	M = F X L	$	-
Accumulated Depreciation, December 31, 2029	N	$	-
Net Book Value (NBV) - Customer Contributions	**O = F - N**	**$**	**-**
Total 2029 Depreciation Expense (Net of Contributions)	**P = E + M**	**$**	**4,665**

Note 1: Assumed 50 year useful life 100% / 50 Years = 2%

Income Taxes
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Income Taxes (000s)	Reference		Annual
Capital Additions for 2029	A		424,046
Less: Contributions	B		-
CCA Deductions 2029	C		16,962
Ending UCC	D = A - B - C	$	407,085
Future Income Taxes			
CCA Deductions 2029	C	$	16,962
Accumulated Depreciation, December 31, 2029	E = I - N From Page 1		4,665
Difference CCA/Depreciation	F = C - E		12,297
Future Tax Rate	G		31.00%
Future Income Tax Liability	H = F X G		3,812
Income Tax Effects of Increased Return			
Return on Rate Base	I = H from Page 3	$	29,024
Equity Return (grossed up)	J = G from Page 3 / (1-G)		25,075
Taxable Income from Return on Rate Base	K = J	$	25,075
Income Tax Expense			
Taxable Income from Return on Rate Base	L	$	25,075
Add: Depreciation	M = P from Page 1		4,665
Less: CCA	N = 2029 CCA		(16,962)
	O = L + M + N		12,778
Corporate Tax Rate	G		31.00%
Current Income Tax Expense	P = O X G		3,961
Future Income Tax Expense	Q = (-M - N)* G		3,812
Total Income Tax Expense	**R = P + Q**	**$**	**7,773**

2029 Rate Base & Cost of Capital
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Rate Base & Cost of Capital (000s)	**Reference**		
Net Book Value, Capital Investment	A = K from Page 1	$	419,382
Net Book Value, Contributions	B = O from Page 1		-
Future Income Taxes	C = H from Page 2		(3,812)
Projected Rate Base	**D = A + B + C**	**$**	**415,570**
Total % Increase from 2025 Actual Year End Rate Base	**E = D / R**		**69.62%**
Return on Debt	F = D X O	$	11,722
Return on Common Equity	G = D X P		17,302
Total Return On Rate Base	H = F + G	$	29,024
Weighted Average Cost of Capital ("WACC")			
Debt	I		60.0%
Common Equity	J		40.0%
Cost of Debt	K		4.23%
Cost of Common Equity	L		9.35%
2025 Average Capitalization (Total Debt plus Common Equity)	M		638,765,377
2025 Average Rate Base*	N		574,368,441
WA Cost of Debt	O = I X K X M/ N		2.82%
WA Cost of Common Equity	P = J X L X M/ N		4.16%
2025 WACC	Q = O + P		6.98%
2025 Year End Rate Base	**R**	**$**	**596,902**

Revenue Requirement
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

2029 Annual Project Revenue Requirement (000s)	Reference		0
Depreciation	A = P from Page 1	$	4,665
[redacted]			
Return on Debt	C = F from Page 3		11,722
Return on Equity	D = G from Page 3		17,302
Income Taxes	E = R from Page 2		7,773
Estimated Annual Project Revenue Requirement	**F = A + B + C + D + E**	**$**	**25,682**
% Increase over 2025 Forecast Revenue Requirement	**G = F / H**		**10.07%**
2025 Revenue Requirement*	**H**	**$**	**255,063**

Total Change in Revenue Requirement Allocated to MECL	**100% = F**	**$**	**25,682**

* 2025 forecast revenue requirement per GRA Negotiated Settlement filed with the Commission on April 4, 2023.

Distribution Rate Impact
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Project Rate Impact	**Reference**		**0**
Total Project Revenue Requirement	A = F from Appendix F X 1000	$	25,681,510
Forecast 2029 kWh Sales	B		1,724,249,644
Forecast Increase Per kWh Project Rate Impact	**C = A / B**	**$**	**0.01489**
Forecast Increase Annual Cost Benchmark Residential Customer (650 kWh per month) before tax	**D = 650 kWh X C X 12 months**	**$**	**116.14**
% Increase over 2025 Forecast Annual Cost for Rural Residential Customer	E = D / I		7.09%
% Increase over 2025 Forecast Annual Cost for Urban Residential Customer	F = D / J		7.21%
Forecast Increase Annual Cost Benchmark General Service Customer (10,000 kWh per month) before tax	**G = 10,000 kWh X C X 12 months**	**$**	**1,786.80**
% Increase over 2025 Forecast Annual Cost for General Service Customer	H = G / K		6.95%
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	I	$	1,639.09
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on June 20, 2022 April 4, 2023.	J		$1,610.89
2025/2026 Annual Cost Benchmark General Service Customer (10,000 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	K	$	25,712.54

IR-87(d) – Confidential Attachment 1

Updated Estimated Impact on Customer Rates Based on Off-Island Capacity being 10% Lower

Depreciation
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Depreciation (000s)	Reference		Annual
Depreciation Expense			
Capital Additions for 2029	A		353,372
Plant Investment for Depreciation	C = A + B	$	353,372
Depreciation Rate (Note 1)	D		2.20%
2029 Depreciation Expense (half year)	E = C X D	$	3,887
Capital Investment			
Capital Investment	A		353,372
Less: Customer Contributions per Annual Depreciation	F		-
Total Capital Investment	G = A + F	$	353,372
Accumulated Depreciation			
Accumulated Depreciation, December 31, 2029	I		3,887
Total Change in Accumulated Depreciation	J = H + I	$	3,887
Net Book Value (NBV) - Capital Investment	**K = C - J**	**$**	**349,485**
Customer Contributions			
Customer Contributions per Annual Depreciation	F	**$**	**-**
Depreciation Expense - Contributions			
Annual Contributions	F	$	-
Depreciation Rate	L		2.20%
Amortization of Customer Contributions	M = F X L	$	-
Accumulated Depreciation, December 31, 2029	N	$	-
Net Book Value (NBV) - Customer Contributions	**O = F - N**	**$**	**-**
Total 2029 Depreciation Expense (Net of Contributions)	**P = E + M**	**$**	**3,887**

Note 1: Assumed 50 year useful life 100% / 50 Years = 2%

Income Taxes
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Income Taxes (000s)	Reference		Annual
Capital Additions for 2029	A		353,372
Less: Contributions	B		-
CCA Deductions 2029	C		14,135
Ending UCC	D = A - B - C	$	339,237
Future Income Taxes			
CCA Deductions 2029	C	$	14,135
Accumulated Depreciation, December 31, 2029	E = I - N From Page 1		3,887
Difference CCA/Depreciation	F = C - E		10,248
Future Tax Rate	G		31.00%
Future Income Tax Liability	H = F X G		3,177
Income Tax Effects of Increased Return			
Return on Rate Base	I = H from Page 3	$	24,186
Equity Return (grossed up)	J = G from Page 3 / (1-G)		20,896
Taxable Income from Return on Rate Base	K = J	$	20,896
Income Tax Expense			
Taxable Income from Return on Rate Base	L	$	20,896
Add: Depreciation	M = P from Page 1		3,887
Less: CCA	N = 2029 CCA		(14,135)
	O = L + M + N		10,648
Corporate Tax Rate	G		31.00%
Current Income Tax Expense	P = O X G		3,301
Future Income Tax Expense	Q = (-M - N)* G		3,177
Total Income Tax Expense	**R = P + Q**	**$**	**6,478**

2029 Rate Base & Cost of Capital
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Rate Base & Cost of Capital (000s)	Reference		
Net Book Value, Capital Investment	A = K from Page 1	$	349,485
Net Book Value, Contributions	B = O from Page 1		-
Future Income Taxes	C = H from Page 2		(3,177)
Projected Rate Base	**D = A + B + C**	**$**	**346,308**
Total % Increase from 2025 Actual Year End Rate Base	**E = D / R**		**58.02%**
Return on Debt	F = D X O	$	9,768
Return on Common Equity	G = D X P		14,418
Total Return On Rate Base	H = F + G	$	24,186
Weighted Average Cost of Capital ("WACC")			
Debt	I		60.0%
Common Equity	J		40.0%
Cost of Debt	K		4.23%
Cost of Common Equity	L		9.35%
2025 Average Capitalization (Total Debt plus Common Equity)	M		638,765,377
2025 Average Rate Base*	N		574,368,441
WA Cost of Debt	O = I X K X M/ N		2.82%
WA Cost of Common Equity	P = J X L X M/ N		4.16%
2025 WACC	Q = O + P		6.98%
2025 Year End Rate Base	**R**	**$**	**596,902**

Revenue Requirement
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

2029 Annual Project Revenue Requirement (000s)	Reference		0
Depreciation	A = P from Page 1	$	3,887
[redacted]			
Return on Debt	C = F from Page 3		9,768
Return on Equity	D = G from Page 3		14,418
Income Taxes	E = R from Page 2		6,478
Estimated Annual Project Revenue Requirement	**F = A + B + C + D + E**	**$**	**20,481**
% Increase over 2025 Forecast Revenue Requirement	**G = F / H**		**8.03%**
2025 Revenue Requirement*	**H**	**$**	**255,063**

Total Change in Revenue Requirement Allocated to MECL	**100% = F**	**$**	**20,481**

* 2025 forecast revenue requirement per GRA Negotiated Settlement filed with the Commission on April 4, 2023.

Distribution Rate Impact
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Project Rate Impact	Reference		0
Total Project Revenue Requirement	A = F from Appendix F X 1000	$	20,481,092
Forecast 2029 kWh Sales	B		1,724,249,644
Forecast Increase Per kWh Project Rate Impact	**C = A / B**	**$**	**0.01188**
Forecast Increase Annual Cost Benchmark Residential Customer (650 kWh per month) before tax	**D = 650 kWh X C X 12 months**	**$**	**92.66**
% Increase over 2025 Forecast Annual Cost for Rural Residential Customer	E = D / I		5.65%
% Increase over 2025 Forecast Annual Cost for Urban Residential Customer	F = D / J		5.75%
Forecast Increase Annual Cost Benchmark General Service Customer (10,000 kWh per month) before tax	**G = 10,000 kWh X C X 12 months**	**$**	**1,425.60**
% Increase over 2025 Forecast Annual Cost for General Service Customer	H = G / K		5.54%
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	I	$	1,639.09
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on June 20, 2022 April 4, 2023.	J		$1,610.89
2025/2026 Annual Cost Benchmark General Service Customer (10,000 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	K	$	25,712.54

IR-87(d) – Confidential Attachment 2

Updated Estimated Impact on Customer Rates Based on Off-Island Capacity being 25% Lower

Depreciation
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Depreciation (000s)	Reference		Annual
Depreciation Expense			
Capital Additions for 2029	A		353,372
Plant Investment for Depreciation	C = A + B	$	353,372
Depreciation Rate (Note 1)	D		2.20%
2029 Depreciation Expense (half year)	E = C X D	$	3,887
Capital Investment			
Capital Investment	A		353,372
Less: Customer Contributions per Annual Depreciation	F		-
Total Capital Investment	G = A + F	$	353,372
Accumulated Depreciation			
Accumulated Depreciation, December 31, 2029	I		3,887
Total Change in Accumulated Depreciation	J = H + I	$	3,887
Net Book Value (NBV) - Capital Investment	**K = C - J**	**$**	**349,485**
Customer Contributions			
Customer Contributions per Annual Depreciation	F	**$**	**-**
Depreciation Expense - Contributions			
Annual Contributions	F	$	-
Depreciation Rate	L		2.20%
Amortization of Customer Contributions	M = F X L	$	-
Accumulated Depreciation, December 31, 2029	N	$	-
Net Book Value (NBV) - Customer Contributions	**O = F - N**	**$**	**-**
Total 2029 Depreciation Expense (Net of Contributions)	**P = E + M**	**$**	**3,887**

Note 1: Assumed 50 year useful life 100% / 50 Years = 2%

Income Taxes
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Income Taxes (000s)	Reference		Annual
Capital Additions for 2029	A		353,372
Less: Contributions	B		-
CCA Deductions 2029	C		14,135
Ending UCC	D = A - B - C	$	339,237
Future Income Taxes			
CCA Deductions 2029	C	$	14,135
Accumulated Depreciation, December 31, 2029	E = I - N From Page 1		3,887
Difference CCA/Depreciation	F = C - E		10,248
Future Tax Rate	G		31.00%
Future Income Tax Liability	H = F X G		3,177
Income Tax Effects of Increased Return			
Return on Rate Base	I = H from Page 3	$	24,186
Equity Return (grossed up)	J = G from Page 3 / (1-G)		20,896
Taxable Income from Return on Rate Base	K = J	$	20,896
Income Tax Expense			
Taxable Income from Return on Rate Base	L	$	20,896
Add: Depreciation	M = P from Page 1		3,887
Less: CCA	N = 2029 CCA		(14,135)
	O = L + M + N		10,648
Corporate Tax Rate	G		31.00%
Current Income Tax Expense	P = O X G		3,301
Future Income Tax Expense	Q = (-M - N)* G		3,177
Total Income Tax Expense	**R = P + Q**	**$**	**6,478**

2029 Rate Base & Cost of Capital
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Rate Base & Cost of Capital (000s)	Reference		
Net Book Value, Capital Investment	A = K from Page 1	$	349,485
Net Book Value, Contributions	B = O from Page 1		-
Future Income Taxes	C = H from Page 2		(3,177)
Projected Rate Base	**D = A + B + C**	**$**	**346,308**
Total % Increase from 2025 Actual Year End Rate Base	**E = D / R**		**58.02%**
Return on Debt	F = D X O	$	9,768
Return on Common Equity	G = D X P		14,418
Total Return On Rate Base	H = F + G	$	24,186
Weighted Average Cost of Capital ("WACC")			
Debt	I		60.0%
Common Equity	J		40.0%
Cost of Debt	K		4.23%
Cost of Common Equity	L		9.35%
2025 Average Capitalization (Total Debt plus Common Equity)	M		638,765,377
2025 Average Rate Base*	N		574,368,441
WA Cost of Debt	O = I X K X M/ N		2.82%
WA Cost of Common Equity	P = J X L X M/ N		4.16%
2025 WACC	Q = O + P		6.98%
2025 Year End Rate Base	**R**	**$**	**596,902**

Revenue Requirement
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

2029 Annual Project Revenue Requirement (000s)	Reference		0
Depreciation	A = P from Page 1	$	3,887
[redacted]			
Return on Debt	C = F from Page 3		9,768
Return on Equity	D = G from Page 3		14,418
Income Taxes	E = R from Page 2		6,478
Estimated Annual Project Revenue Requirement	**F = A + B + C + D + E**	**$**	**23,046**
% Increase over 2025 Forecast Revenue Requirement	**G = F / H**		**9.04%**
2025 Revenue Requirement*	**H**	**$**	**255,063**

Total Change in Revenue Requirement Allocated to MECL	**100% = F**	**$**	**23,046**

* 2025 forecast revenue requirement per GRA Negotiated Settlement filed with the Commission on April 4, 2023.

Distribution Rate Impact
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Project Rate Impact	Reference		0
Total Project Revenue Requirement	A = F from Appendix F X 1000	$	23,046,092
Forecast 2029 kWh Sales	B		1,724,249,644
Forecast Increase Per kWh Project Rate Impact	**C = A / B**	**$**	**0.01337**
Forecast Increase Annual Cost Benchmark Residential Customer (650 kWh per month) before tax	**D = 650 kWh X C X 12 months**	**$**	**104.29**
% Increase over 2025 Forecast Annual Cost for Rural Residential Customer	E = D / I		6.36%
% Increase over 2025 Forecast Annual Cost for Urban Residential Customer	F = D / J		6.47%
Forecast Increase Annual Cost Benchmark General Service Customer (10,000 kWh per month) before tax	**G = 10,000 kWh X C X 12 months**	**$**	**1,604.40**
% Increase over 2025 Forecast Annual Cost for General Service Customer	H = G / K		6.24%
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	I	$	1,639.09
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on June 20, 2022 April 4, 2023.	J		$1,610.89
2025/2026 Annual Cost Benchmark General Service Customer (10,000 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	K	$	25,712.54

IR-87(d) – Confidential Attachment 3

Updated Estimated Impact on Customer Rates Based on Off-Island Capacity being 50% Lower

Depreciation
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Depreciation (000s)	Reference		Annual
Depreciation Expense			
Capital Additions for 2029	A		353,372
Plant Investment for Depreciation	C = A + B	$	353,372
Depreciation Rate (Note 1)	D		2.20%
2029 Depreciation Expense (half year)	E = C X D	$	3,887
Capital Investment			
Capital Investment	A		353,372
Less: Customer Contributions per Annual Depreciation	F		-
Total Capital Investment	G = A + F	$	353,372
Accumulated Depreciation			
Accumulated Depreciation, December 31, 2029	I		3,887
Total Change in Accumulated Depreciation	J = H + I	$	3,887
Net Book Value (NBV) - Capital Investment	**K = C - J**	**$**	**349,485**
Customer Contributions			
Customer Contributions per Annual Depreciation	F	**$**	**-**
Depreciation Expense - Contributions			
Annual Contributions	F	$	-
Depreciation Rate	L		2.20%
Amortization of Customer Contributions	M = F X L	$	-
Accumulated Depreciation, December 31, 2029	N	$	-
Net Book Value (NBV) - Customer Contributions	**O = F - N**	**$**	**-**
Total 2029 Depreciation Expense (Net of Contributions)	**P = E + M**	**$**	**3,887**

Note 1: Assumed 50 year useful life 100% / 50 Years = 2%

Income Taxes
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Income Taxes (000s)	Reference		Annual
Capital Additions for 2029	A		353,372
Less: Contributions	B		-
CCA Deductions 2029	C		14,135
Ending UCC	D = A - B - C	$	339,237
Future Income Taxes			
CCA Deductions 2029	C	$	14,135
Accumulated Depreciation, December 31, 2029	E = I - N From Page 1		3,887
Difference CCA/Depreciation	F = C - E		10,248
Future Tax Rate	G		31.00%
Future Income Tax Liability	H = F X G		3,177
Income Tax Effects of Increased Return			
Return on Rate Base	I = H from Page 3	$	24,186
Equity Return (grossed up)	J = G from Page 3 / (1-G)		20,896
Taxable Income from Return on Rate Base	K = J	$	20,896
Income Tax Expense			
Taxable Income from Return on Rate Base	L	$	20,896
Add: Depreciation	M = P from Page 1		3,887
Less: CCA	N = 2029 CCA		(14,135)
	O = L + M + N		10,648
Corporate Tax Rate	G		31.00%
Current Income Tax Expense	P = O X G		3,301
Future Income Tax Expense	Q = (-M - N)* G		3,177
Total Income Tax Expense	**R = P + Q**	**$**	**6,478**

2029 Rate Base & Cost of Capital
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Rate Base & Cost of Capital (000s)	Reference		
Net Book Value, Capital Investment	A = K from Page 1	$	349,485
Net Book Value, Contributions	B = O from Page 1		-
Future Income Taxes	C = H from Page 2		(3,177)
Projected Rate Base	**D = A + B + C**	**$**	**346,308**
Total % Increase from 2025 Actual Year End Rate Base	**E = D / R**		**58.02%**
Return on Debt	F = D X O	$	9,768
Return on Common Equity	G = D X P		14,418
Total Return On Rate Base	H = F + G	$	24,186
Weighted Average Cost of Capital ("WACC")			
Debt	I		60.0%
Common Equity	J		40.0%
Cost of Debt	K		4.23%
Cost of Common Equity	L		9.35%
2025 Average Capitalization (Total Debt plus Common Equity)	M		638,765,377
2025 Average Rate Base*	N		574,368,441
WA Cost of Debt	O = I X K X M/ N		2.82%
WA Cost of Common Equity	P = J X L X M/ N		4.16%
2025 WACC	Q = O + P		6.98%
2025 Year End Rate Base	**R**	**$**	**596,902**

Revenue Requirement
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

2029 Annual Project Revenue Requirement (000s)	Reference		0
Depreciation	A = P from Page 1	$	3,887
Operating Expenses	= Column K - Year 2029 /1000		1,320
Return on Debt	C = F from Page 3		9,768
Return on Equity	D = G from Page 3		14,418
Income Taxes	E = R from Page 2		6,478
Estimated Annual Project Revenue Requirement	**F = A + B + C + D + E**	**$**	**27,321**
% Increase over 2025 Forecast Revenue Requirement	**G = F / H**		**10.71%**
2025 Revenue Requirement*	**H**	**$**	**255,063**

Total Change in Revenue Requirement Allocated to MECL	**100% = F**	**$**	**27,321**

* 2025 forecast revenue requirement per GRA Negotiated Settlement filed with the Commission on April 4, 2023.

Distribution Rate Impact
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Project Rate Impact	**Reference**		**0**
Total Project Revenue Requirement	A = F from Appendix F X 1000	$	27,321,092
Forecast 2029 kWh Sales	B		1,724,249,644
Forecast Increase Per kWh Project Rate Impact	**C = A / B**	**$**	**0.01585**
Forecast Increase Annual Cost Benchmark Residential Customer (650 kWh per month) before tax	**D = 650 kWh X C X 12 months**	**$**	**123.63**
% Increase over 2025 Forecast Annual Cost for Rural Residential Customer	E = D / I		7.54%
% Increase over 2025 Forecast Annual Cost for Urban Residential Customer	F = D / J		7.67%
Forecast Increase Annual Cost Benchmark General Service Customer (10,000 kWh per month) before tax	**G = 10,000 kWh X C X 12 months**	**$**	**1,902.00**
% Increase over 2025 Forecast Annual Cost for General Service Customer	H = G / K		7.40%
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	I	$	1,639.09
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on June 20, 2022 April 4, 2023.	J		$1,610.89
2025/2026 Annual Cost Benchmark General Service Customer (10,000 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	K	$	25,712.54