# Electric System On-Island Capacity Alternatives for Prince Edward Island

Examination of MECL Application for On-Island Capacity Supply

**Prepared for Island Regulatory and Appeals Commission**

**Final Report**

April 9, 2026


AUTHORS

Sabine Chavin
Bob Fagan
Ida Weiss

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

# CONTENTS

# SUMMARY FINDINGS

Synapse Energy Economics (Synapse) has reviewed the application of Maritime Electric Company, Ltd. (MECL) requesting approval for Prince Edward Island (PEI) local (i.e., on-Island) electric capacity supply increases consisting initially of a pair of 50 MW combustion turbines (CT), 100 MW in total, for installation at the Charlottetown generation plant site. This report conveys our analysis of the request, and our findings based on MECL's application and its accompanying documentation. The documentation consists primarily of MECL consultant Sargent and Lundy's (S&L) Capacity Supply Report (CSR) and its addendum to that report which considers the impact on capacity supply needs of an extreme weather event.

Our summary findings are as follows:

1. In its supplemental request from August 2025, MECL has narrowly framed the major on-Island capacity need as immediately requiring the proposed 100 MW of combustion turbines from ProEnergy. A reasonable alternative to the combustion turbines is a similarly sized battery energy storage system (BESS) resource, available in a similar time frame as the CT project. A BESS resource provides dispatchable capacity that replaces firm New Brunswick import capacity purchases (as does the CT project) but it must be charged with energy during the "off peak" hours when not needed for capacity provision. MECL has not fully evaluated the benefits of a BESS capacity alternative and has not sufficiently compared the costs and availability of the BESS alternative with the proposed CT project.

2. The capacity need outlined in the application and the supporting reports is based on MECL's "use case" requiring on-Island capacity to 1) meet energy and capacity obligations, 2) improve load service during electrical disconnection from the mainland, and 3) achieve sustainability targets. Secondary considerations include voltage support and transmission contingency support during high load conditions. These represent reasonable use case considerations for on-Island capacity supply procurement.

3. Both the proposed CT project and a BESS resource alternative (at either a 4-hour duration storage capacity, or a 6-hour duration storage capacity) fully support these use cases. MECL's target of meeting 50% of capacity requirements with on-Island supply is reasonable. Both resource options reduce the risk of curtailment of energy imports from New Brunswick Power during the tightest system conditions. Neither option fully mitigates the potential for loss of load during extreme New Brunswick – PEI interconnection "full disconnection" events, nor is such mitigation intended given the low probability of occurrence of such an event.

4. For capacity provision alone, a BESS resource alternative (at 4-hour or 6-hour duration) is likely less expensive than the CT project alternative, on both an installed cost basis and on a net present cost basis. This conclusion is based on current market conditions and S&L estimates for BESS resource costs. While MECL states that its proposed CT project is the most cost-effective on-Island alternative, its analysis fails to quantitatively

support this conclusion. The BESS resource is less expensive even considering that a 4-hour duration BESS resource may only provide roughly 90% of the capacity provided by either the CT project or a 6-hour duration BESS project.

5. A BESS resource option, often considered as a 20-year lifetime project, continues to have value after its first 20 years. The cost comparison continues to favor the BESS capacity resource option even after accounting for battery storage augmentation needs required to compare resource options across the same 50-year period.

6. A BESS capacity resource alternative also contains an additional energy value premium associated with operating the BESS resource. The BESS resource can reduce the effective cost of some of the energy procured from New Brunswick Power (NB Power) through "time shifting" of procurement. The BESS resource can also be operated to avoid energy costs from generating electricity using on-Island CT resources, whose marginal or operating costs are much higher in general than average procured energy costs from New Brunswick Power.

7. The BESS capacity resource alternative fully supports increasing the amount of on-Island renewable energy (wind or solar) in support of PEI sustainability objectives. A BESS capacity resource is potentially a more cost-effective resource than a CT for integrating greater amounts of on-Island wind or solar energy into MECL's system.

8. The presence of on-Island wind energy resources that exhibit high output performance correlated with low temperatures and higher peak load – at times of highest New Brunswick energy curtailment risk - is a synergistic benefit for Prince Edward Island electricity systems. MECL should more fully and carefully examine these synergies in the context of a need for a new Integrated System Plan.

   A BESS resource option leverages these synergies by allowing MECL to 1) more effectively utilize PEI wind energy during the intervals it is most needed, and 2) store energy as needed (for later use) during the periods in which wind output is high or at a maximum (or New Brunswick import energy is more readily available or less expensive). "Grid-forming"[1] BESS resources also allow PEI wind to operate fully during a disconnection event.

   The actual "ELCC" (see footnote 54) of wind resources providing winter energy is not directly relevant to the capacity cost comparisons made in this report between BESS and combustion turbine resources. While increased wind resources on PEI will play an important role in meeting energy demands, and they will contribute to on-Island capacity shares, the focus of this report is not on the role that wind plays in contributing to resource adequacy requirements, but rather how their energy presence coupled with BESS capacity resource availability is a highly complementary resource pairing for PEI.

[1] See footnote 13 on "grid-forming" capabilities for battery energy storage systems.

# 1. INTRODUCTION AND BACKGROUND

This report examines a Maritime Electric Company, Ltd. ("MECL") application to the Prince Edward Island Regulatory and Appeals Commission ("Commission") to procure additional on-Island electricity capacity supply. Synapse Energy Economics ("Synapse") reviewed a series of documents related to the application to inform its evaluation of MECL's proposal.

On December 18, 2024, MECL submitted an *Application and Evidence for its On-Island Capacity for Security of Supply Project* ("Proposed Project"), docket UE20742. On August 14, 2025, MECL submitted a *Supplemental Filing re: On-Island Capacity for Security of Supply Project* ("Supplemental Filing") in the same docket. The December application requested approval for 150 MW of on-island capacity supply, composed of combustion turbine ("CT") (50 MW), reciprocating engine ("RICE") (90 MW), and battery energy storage system ("BESS") (10 MW) resources. The August Supplemental Filing requested a modification to the December request, to 100 MW of CT resource.

The materials submitted by MECL as appendices to its Proposed Project application included a *Capacity Resource Study – Evaluation of Various Technology Options for Maritime Electric Company* prepared by Sargent and Lundy ("S&L") for MECL, dated December 9, 2022, and a follow-up report, *Extreme Weather Event Capacity Impact – Addendum to December 2022 Maritime Electric Capacity Resource Study* for MECL dated July 12, 2023.

MECL also filed a project update on April 23, 2025, describing changes to the patterns of MECL's winter peak period load attributes. The update noted that peak load attributes are changing with winter temperatures due to an effect of electrification of space heating needs on Prince Edward Island. In addition, the PEI IRAC held a technical conference on the topic on September 25, 2025. MECL further filed a post-technical conference update letter on October 16, 2025.

In addition to discussing MECL's Proposed Project and the Supplemental Filing, this report also presents Synapse's analysis of the responses to Interrogatories provided by MECL,[2] the information provided during the September 2025 technical conference and MECL's update letter to the PEI IRAC on October

[2] Interrogatories were submitted to MECL by Synapse (two sets, with responses in May and November, 2025); Stephen Chandler, CEM (responses in May, 2025); and Energy Storage Canada (responses in May, 2025).

16, 2025, and relevant information concerning electric power system developments in New Brunswick[3] and Nova Scotia.[4]

The relevant matters affecting the economics of MECL's current on-island capacity resource choice addressed in this report include the following:

- The "use case" for which on-Island capacity is needed
- The magnitude, type, costs, and attributes of capacity resource options
- The means to minimize "curtailment" of energy from New Brunswick at critical times
- The role and value of existing and new wind power resources on PEI
- The ongoing policy aims of PEI to reduce levels of energy imports from New Brunswick and increase supply from renewable sources on the island

The structure of this report is as follows.

This Chapter 1 briefly summarizes relevant activity affecting consideration of the Proposed Project. This activity includes MECL's 2020 Integrated Supply Plan and recent activities in New Brunswick and Nova Scotia affecting the transmission and resource adequacy of the region. Relevant events in New Brunswick and Nova Scotia include Nova Scotia Power's recent completion of its initial utility-scale battery energy storage projects, New Brunswick Power's approval of transmission grid reinforcements, and the joint NB-NS project of a second 345 kV transmission tie line.

Chapter 2 examines and evaluates MECL's Application and assesses MECL's capacity supply need. The chapter also contains cost comparisons between the proposed CT project and a 100 MW BESS project.

Chapter 3 further analyzes the cost of MECL's Proposed Project and the cost of alternatives to secure on-island capacity supplies. It provides explicit illustrations of the way in which battery energy storage resources, a capacity alternative to the Proposed Project, could operate on PEI during winter peak periods. It includes analysis that demonstrates how the capacity alternative, like the Proposed Project, would reduce the need for New Brunswick imports during times when the probability of curtailment of New Brunswick import supplies is higher.

Chapter 4 provides conclusions and recommendations. Confidential Appendix A contains cost computations for alternative resource options and utilizes MECL's accounting framework.

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[3] The New Brunswick Energy and Utilities Board has approved transmission and dynamic reactive support projects requested by New Brunswick Power to further support the transmission grid in southeastern New Brunswick.

[4] Nova Scotia Energy Board approval of the New Brunswick – Nova Scotia second 345 kV "Reliability Tie" transmission line, in Matter M12217, on November 20, 2025. NS Power completion of two of the three approved 50 MW/200 MWh battery energy storage projects in Nova Scotia.

## 1.1. 2020 Integrated System Plan

In 2020, MECL developed and submitted to the PEI IRAC an Integrated System Plan (ISP).[5] A subset of its major elements included the following:

- Adding 50–75 MW of CT capacity at the Charlottetown Plant Site, with a "year of need" of 2024
- Replacement of the two CTs at Borden (40 MW, total) with a "year of need" of 2030
- Consideration of an on-island capacity supply to meet 50 percent of capacity needs on island[6]
- Completion of an eventual third west-to-east 138 kV line, plus other transmission and distribution line and substation projects

At the time of the ISP, MECL stated that storage was uneconomic and that MECL could "secure both capacity and ancillary services more economically from other sources."[7] Thus, BESS resources were not part of the capacity options listed for consideration to meet the 50 percent target for on-Island capacity needs.[8]

The load forecast contained in the ISP projected an island winter peak of 337 MW in 2025, and 374 MW in 2030, the last year of the forecast. MECL's forecast peak in the ISP for 2025 was 306 (292 with 14 MW of interruptible load).[9] The 2025 and 2030 forecast contained in MECL's Application in this case are higher than the projections made in the ISP; MECL's 2030 peak is projected to be 350 MW in 2025 and 383 MW in 2030, rising to 409 MW in 2033.

The ISP indicates in numerous places throughout the document a need to keep New Brunswick-Prince Edward Island imports below 300 MW, for transmission purposes.

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[5] MECL, Integrated System Plan (ISP), September 30, 2020. A Summary section, at pages 82-83 includes Table 30, which contains a summary of capital projects.

[6] ISP, page iv, "Add on-Island generating capacity, over and above the generator proposed in 2024, to provide backup to the growing Island load and reduce the Island's dependence on mainland capacity to less than 50 per cent. This generation should be located near a major load centre on the 69 kV system to extract the maximum benefit from the equipment."

[7] MECL 2020 ISP, page ii, "The cost of energy storage continues to fall as the technology matures but remains uneconomic. Individual customers may choose to install storage for their own needs. Maritime Electric does not believe that utility control of an array of individual customer devices, with the control devices, communications and security needed to undertake the program, will provide an economic capacity resource at this time. Maritime Electric can secure both ancillary services and capacity more economically from other sources."

[8] Table 15, Maritime Electric Peak Load and Capacity Options, page 32.

[9] Table 12 and Table 15, pages 27 and 32.

**Synapse Response to ISP**

Synapse submitted a report to the PEI IRAC in April of 2022.[10] Based on a capacity expansion and production cost analysis using the EnCompass modeling environment, Synapse found that it was cost-effective to plan for increased battery energy storage on PEI to address capacity needs. It also showed that increases in wind supply were cost-effective under scenarios where New Brunswick energy prices were higher than the base assumptions, or if PEI implemented more stringent requirements for renewable resource requirements.[11]

## 1.2. New Brunswick and Nova Scotia Relevant Activities

At least three ongoing electric system activities in Nova Scotia and New Brunswick are relevant to the on-Island capacity supply considerations on PEI. Those developments include the following:

1) Nova Scotia recently completed the first two of three 50 MW, 200 MWh BESS projects at three substation locations in Nova Scotia. The Nova Scotia Utility and Review Board (NS UARB, now, Nova Scotia Energy Board) approved those installations on the basis of Nova Scotia's capacity needs and requirements to integrate more renewable energy to meet an 80 percent renewable energy legislative requirement by 2030. Synapse provided expert witness support to the NS UARB in the Matter 11539.

   From the NS UARB's approval Decision (June 13, 2024):[12]

   > [10] The BESS Project will provide firm dispatchable capacity for four hours to meet peak system demand. The BESS Project will allow NS Power to store low-cost energy and energy generated off-peak and use that energy during higher cost on-peak periods. The BESS Project will be charged during periods of high wind and low load which improves the value of renewable resources that are intermittent. Voltage can be supported to meet local system needs and respond to disruptions in other areas of the grid. The System Operator will be afforded the ability to balance system generation and load, keeping the system frequency within the limits prescribed by the ECC. The BESS Project will be able to provide

[10] Synapse Energy Economics, *Prince Edward Island Resource Planning and Maritime Electric Capital Expenditures: Alternatives to MECL Integrated System Plans and Impact on MECL Capital Expenditures*, April 27, 2022. Prepared for the PEI Regulatory and Appeals Commission.

[11] Synapse 2022 report, Executive Summary at page iii, "The modeled scenarios presume an increase of 30 MW of new wind energy in 2023, and 40 MW of new wind energy in 2025. Beyond those planned installations, the core optimized scenarios do not add any additional wind resources on PEI. That result is dependent on both the continuing existence of relatively low-cost energy from New Brunswick, and no new stringent requirement that PEI obtain much greater levels of electric energy from renewable resources. If either of those circumstances change, increasing the amount of wind energy on PEI is likely to be an optimal outcome. We see an increase in on-Island wind builds of up to 120 MW in our New Brunswick high energy price scenario, with additional wind coming online during the 2030 decade."

[12] Nova Scotia Utility and Review Board Decision in Matter 11539, pages 5-6. Available at https://nserbt.ca/sites/default/files/NSUARB%20Board%20Decision%20-%20Nova%20Scotia%20Power%20Incorporated%20%28M11539%29.pdf.

power to the grid in response to sudden changes in load and unplanned generation outages.

[11] Synapse noted that other attributes of the BESS Project reflect a combined multi-functional grid support capability that can quickly respond to normal and contingency events in support of core frequency, voltage and load following requirements in both automated and manually dispatched modes. Although the BESS Project cannot fully displace older assets, Synapse considers this makes the BESS Project valuable for supporting reliability and effective at displacing carbon intensive and more expensive resources.

[12] In response to Synapse IR-4, NS Power stated that the BESS Project provides grid-forming capability that the North American Electric Reliability Corporation recommends implementing to reduce potential reliability risks.

This matter in Nova Scotia is relevant to the on-Island capacity considerations on PEI because it demonstrates how a neighboring province with similar renewable resource and capacity needs and winter peak requirements secured a reliable capacity resource using a BESS resource. Operating the BESS in grid-forming mode[13] would be a key attribute of any BESS resource installed on PEI to support "islanded" operations in the event of a disconnection from New Brunswick. It is relevant to reliability because it preserves the option to allow on-Island wind resources to operate if PEI is disconnected from the mainland, which can allow for wind capacity to be fully utilized; S&L had expressed concern that under a disconnection event, wind resources might not be able to be relied upon (Capacity Resource Study, page 11).

Grid-forming (GFM) BESS resources entail use of standard BESS resource hardware (e.g., battery modules, inverters, switches, transformers, controls). The resource is configured for use in such a way that is different from "grid-following" inverter resources (e.g., such as seen on most solar PV panels) that rely on the rest of the grid to enable proper operation. As noted in Appendix B (Attachment 1) to this report, when a BESS is configured to operate in grid-forming mode,

> "…the GFM control is fundamentally different. In the short time immediately after something changes in the grid, the GFM control objective is to maintain a constant voltage phasor, in a similar fashion to synchronous machines.* …
>
> * https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Grid_Forming_Technology.pdf
>
> Synchronous generators also have inherent physical attributes like inertia, which is desirable in many ways, although these attributes also create stability challenges that have been studied for over 100 years. If thoughtfully designed, GFM controls can mimic the desirable characteristics of

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[13] See, for example, *Grid-Forming Battery Energy Storage Systems*, from Energy System Integration Group (ESIG) and GridLAB, an ESIG Brief for Decisionmakers, March 2025. Available at https://www.esig.energy/wp-content/uploads/2025/03/ESIG-GFM-BESS-brief-2025.pdf. See also for example, NERC (North American Electric Reliability Corporation), *White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems,* September 2023. Available at https://www.nerc.com/globalassets/our-work/reports/white-papers/white_paper_gfm_functional_specification.pdf and provided as attachments in Appendix B of this report.

conventional synchronous generators while avoiding some of the undesirable attributes due to the flexibility of these inverter-based controls." [Appendix B, Attachment 1, page 2]

The 100 MW BESS alternative considered in this report is roughly 25% of PEI's peak load. The first 150 MW of BESS in Nova Scotia is roughly 7% of their peak load (2,268 MW in winter 2026/27). However, Nova Scotia is in the process of considering replacement of capacity resources for the 2030 time frame and both batteries and combustion turbines will be under assessment in the 2026 integrated resource plan exercise in Nova Scotia. It is likely that battery resources as a share of firm capacity needs will continue to increase in Nova Scotia. While the scale is different, the dispatchable firm capacity attributes are roughly the same, and the associated flexibility value provided to either province from the BESS resource is essentially the same. While PEI and Nova Scotia would likely operate the resources differently because supply mix conditions are different (Nova Scotia does not depend on import energy for most of its load, unlike PEI), the same principles apply to both provinces – BESS alternatives allow for purchase of less expensive energy during off-peak times, avoidance of more expensive energy during on-peak times, and very fast contingency response capability (e.g., reserves and frequency response regulation) at all times.

2) New Brunswick Power and Nova Scotia Power[14] are in the process of constructing a second 343 kV tie line between the two provinces.[15] New Brunswick Power also received approval from the New Brunswick Energy and Utilities Board for a dynamic reactive supply project at a key location in the Salisbury area and has approved additional transmission system support work in the southeastern portion of its transmission system.[16] The combination of these projects will reinforce the overall grid in New Brunswick, which can have effects on the overall availability of firm and non-firm energy supply to PEI. NB Power also recently released an RFP for installation of a 50 MW BESS project.[17]

   While these transmission system developments do not directly affect the firm import transmission capacity (300 MW) between New Brunswick and PEI, as noted they improve New Brunswick's overall transmission reliability which means that under the most stressful conditions in the region, there is a greater probability that New Brunswick will be better positioned to maintain flows to PEI than absent these additional system elements.

3) New Brunswick Power has recently been considering the installation of an additional 400 MW of CT capacity using the same ProEnergy CT equipment considered for MECL's

[14] The transmission line entity Wasoqonatl Transmission Inc. is in partnership with Nova Scotia Power.

[15] https://www.nbpower.com/en/about-us/projects/new-brunswick-nova-scotia-interprovincial-transmission-line-project.

[16] https://nbeub.ca/uploads/2025%2007%2025%20-%20Matter%20EL-001-2025%20-%20Decision.pdf.

[17] https://www.nbpower.com/en/about-us/news-media-centre/news/2025/nb-power-invites-expressions-of-interest-for-15-year-battery-storage-partnership/#:~:text=The%20REOI%20calls%20for%20battery,lowest%20long%2Dterm%20price.%E2%80%9D.

Application in this case.[18] The installation would be in the Moncton area of New Brunswick, and it would further support NB Power's ability to provide firm capacity imports to PEI.

# 2. REVIEW OF MECL APPLICATION AND CAPACITY SUPPLY NEED

MECL's December 2024 application for on-island capacity supply and its Supplemental Application from August of 2025 seek approval at this time for 100 MW of on-island CT capacity (its Proposed Project). The original December 2024 application sought approval for a total of 150 MW of capacity: 50 MW of CT, 90 MW of RICE, and 10 MW of four-hour duration BESS. MECL's October 16, 2025, project update letter to the PEI IRAC indicates MECL would separately submit updated requests for an additional 50 MW of capacity beyond the 100 MW CT if PEI IRAC approved the Supplemental Application.[19] This chapter examines the key aspects of MECL's Application and reviews MECL's capacity supply need.

## 2.1. Review of MECL Application

MECL filed its application for approval of a 2024 Supplemental Capital Budget Request in December of 2024. Its application is supported by two S&L reports, a 2022 Capacity Resource Study and an addendum to that study (July 2023) assessing the capacity impact of an extreme weather event that occurred in February 2023. MECL amended its application in August 2025 with a requested change to the magnitude, type, and timing of its on-island capacity supply request. MECL also provided updates to the application in April and October of 2025 and responded to interrogatories in May and October of this year. The PEI IRAC held a technical conference on the topic in September of 2025. This section of the report addresses the substance of these application materials, including a discussion and critique of the major elements of MECL's application.

### Application December 2024

The December 2024 application includes S&L's 2022 Capacity Resource Study and S&L's 2023 Extreme Weather Event – Capacity Impact addendum as appendices. Those reports form the analytical basis for MECL's stated capacity need and resource portfolio solution. The December 2024 application explains the proposed project at that time (50 MW CT, 90 MW RICE, 10 MW BESS) and how the assessment of the February 2023 extreme weather event affected S&L's recommendation to increase the near-term on-island capacity installation from an initial 85 MW of RICE technology (as presented in the 2022

[18] https://www.nbpower.com/en/about-us/news-media-centre/news/2025/nb-power-announces-new-generation-capacity-expansion-project-and-development-partner/.

[19] MECL, October 16, 2025, Update Letter at page 2.

Capacity Resource Study)[20] to 150 MW of combined RICE, CT, and BESS technology (as presented in the 2023 addendum and the December 2024 application).[21]

The December 2024 application provides background on MECL's system, energy and peak load growth projections,[22] capacity requirements forecast, and resource adequacy assessment.[23] It states the purpose of the project is to "serve as peaking and backup capacity for responding to unplanned system events" and responding to "hold to schedule directives from NB Power." It further states the project will "reduce the need for off-island capacity purchases" and "support additional renewable energy resource development on PEI" and "enhance the reliability and security of electricity supply."[24]

The application provides an overview of PEI's earlier reliance on imported oil to generate electricity, prior to the 1977 installation of the first two subsea cables (with 100 MW of firm import capacity),[25] and notes that two additional cables (cables 3 and 4) were installed in 2017. Those cables increased the combined physical capacity for imports to 560 MW, with a firm import capacity of 300 MW.[26] Sections 7.2.2 and 7.2.3 of the Application discuss mainland transmission system limitations and disconnection issues.

The application describes the proposed project, including a net present value analysis of *just* the proposed project,[27] in comparison to a scenario with no project and continuing procurement of capacity from New Brunswick. The application does not compare the net present value of the proposed project to any other specific alternative on-island capacity supply project.

Section 7.0 of the application explains the project justification, including seven specific points associated with increased on-island capacity resources. It includes a figure showing how the proposed project

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[20] Capacity Resource Study, Table 6-10 (page 88), Estimated Portfolio D Capacity Sources, 85 MW (RICE) in 2025 rising to 125 MW (RICE total) in 2030 and beyond.

[21] Sargent & Lundy. Extreme Weather Event Capacity Impact addendum, July 12, 2023, at page 22 (revision of 85 MW recommendation to a range of 125-150 MW), and Application at page 7 (proposing 50 MW CT, 90 MW RICE, and 10 MW BESS) and other places, including Tables 13 and 14 at pages 62 and 64.

[22] Application, Figure 14 (page 38); and Figure 15 and Table 8 (pages 39-40 ).

[23] Application, Table 9 (page 44) and Table 10 (page 45).

[24] Page 13. MECL confirmed these "purpose" points as the primary use case for the project in response to Synapse IR-2 a (second set of IRs, November 12, 2025). MECL also listed in that response additional use case considerations (i.e., improved load-serving capability during disconnection events, voltage support, and transmission contingency support).

[25] While each of the original cables has a capacity of 100 MW, the firm import capacity is based on the contingency circumstance in which one cable connection is lost (N-1).

[26] Application, pages 16-17.

[27] Table 14, page 64.

capacity levels will increase the on-island capacity supply to roughly historical levels (50 percent of winter peak) noted in the Capacity Resource Study.[28]

Section 8.0 of the application describes the alternatives considered by MECL and S&L in their analysis. It includes subsections on increased transfer capacity to New Brunswick (Section 8.1), generation expansion in New Brunswick (Section 8.2), and additional on-island BESS capacity (Section 8.3). Notably, Section 8.3 as characterized by MECL focuses on BESS capacity ability to reduce system peak. However, we note that supply-side BESS capacity is not a load-reducing resource, but rather a capacity supply resource with the ability to effectively shift energy production for delivery to the grid at different times. Section 8.0 does not provide a comparative net present value analysis for an alternative on-island capacity supply project.

The last sections of the application address greenhouse gas (GHG) emission effects and an estimate of the impact of the proposed project on customer rates, revenue requirement, and rate base. While Figure 32 of the Application indicates that the proposed CTs will have a very small impact on PEI GHG emissions relative to other GHG sources on PEI, the Capacity Resource Study shows that energy purchases from New Brunswick are the source of 99.5 percent of historical carbon emissions. Therefore, while the proposed CTs may not materially increase PEI GHG emissions, they also do not act to reduce existing emissions associated with New Brunswick energy imports. The Capacity Resource Study also includes sections describing the role of both battery energy storage and new wind resources in reducing GHG emissions associated with MECL's energy supplies.[29]

## Capacity Resource Study December 2022

The initial 2022 Capacity Resource Study compared capacity alternatives to meet the on-island capacity supply need using three MECL "goals and needs": (1) meeting both energy and capacity obligations; (2) improving MECL's ability to serve load during a disconnection event from the mainland; and (3) achieving sustainability targets, which are essentially GHG emission targets. Almost all of PEI's historical electricity sector GHG emissions are from energy purchases from New Brunswick.[30] Considering these three goals, the Capacity Resource Study recommended a final resource portfolio consisting of 85 MW of near-term RICE resource procurement.

As noted above, the Capacity Resource Study reviewed resource planning considerations and carbon emissions planning in Sections 2 and 3 of the report. Section 2 included an illustration of an expected winter day system dispatch during a disconnection event. It also included descriptions of the nine total disconnection events that have occurred since 2004: namely, five partial disconnection events and four

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[28] Capacity Resource Study, page 9, "Historically, Maritime Electric's dispatchable capacity (127 MW) has been approximately 50% of peak load; however, this number (89 MW) is now only just above 30% of peak load."

[29] Capacity Resource Study, Sections 3.2 and 3.3, pages 29-39.

[30] Capacity Resource Study, Table ES-2.

full disconnection events (only one full disconnection has occurred since the installation of cables 3 and 4 in 2017).[31]

The Capacity Resource Study Section 4 contained a description of the capacity technologies considered, and Section 5 contained a screening analysis of those technologies. Notably, Section 5.2.3 described the characteristics of the BESS resources for contributions towards energy and capacity obligations, meeting needs during a disconnection event, and their value to help PEI reach sustainability targets.

The Capacity Resource Study noted that RICE, CT, and BESS resources are all "excellent resource[s] for meeting capacity obligations."[32] It noted the energy limitations that accompany both RICE/CT and BESS resources. The study also caveated the ability of BESS resources to contribute to needs when a mainland disconnection event occurs. As noted in the Discussion section below, Synapse is of the opinion that BESS's ability to contribute to capacity and energy needs during a disconnection event is greater than described by S&L in the Capacity Resource Study in Section 5, primarily because a "grid forming" configuration[33] for BESS resources can provide the direct ancillary service support required to allow wind resources to operate during a disconnection event.

Section 6, the final section of the Capacity Resource Study, addresses four final portfolios considered and describes the one portfolio recommended by S&L for on-island capacity supply. The four final portfolios included a mix of different capacity types and quantities, with Portfolios A, B, and C all containing a 50 MW new BESS resource, and Portfolios B, C, and D containing 85 to 125 MW of new diesel or RICE capacity. The four portfolios all contained the same level of total capacity and total energy, for the years 2023 through 2032.

The Capacity Resource Study recommended Portfolio D based in part on purported cost-effectiveness,[34] although S&L *did not* provide a quantitative measure of the cost-effectiveness of the selected or other portfolios.[35] The reports states that a BESS resource was not included in the final recommended

[31] Capacity Resource Study, page 14.

[32] Capacity Resource Study, Table ES-3 and Table 5-9.

[33] See grid-forming references in footnote 13. A grid-forming BESS resource would allow for the BESS resource to provide voltage, frequency and stability support even when PEI is disconnected from the New Brunswick grid.

[34] Capacity Resource Study, page 89, "This portfolio was selected due to its ability to most cost-effectively meet the three most critical needs of Maritime Electric: 1) [energy and capacity obligations]; 2) supporting the system if disconnected; and 3) supporting sustainability targets."

[35] In response to IR-3 from Synapse, which asked a series of questions concerning the cost-effectiveness claim and sought further information from MECL or S&L on the supporting analysis, MECL and S&L did not provide further information beyond the comparative resource capital cost estimates contained in Appendix A to the report. The response also noted "Detailed energy supply models were not generated as these assets are intended primarily for peaking or backup resources (i.e., with limited energy output), and with their limited energy output the cost of energy supply had minimal influence on technology selection."

portfolio because of solution effectiveness and cost.[36] In the discussion subsection that follows, we address the cost and the solution effectiveness of the capacity alternatives.

### Extreme Weather Event Capacity Impact July 2023

MECL submitted an addendum to its Capacity Resource Study in July of 2023. The addendum addressed the impact of the extreme cold weather event of February 3–5, 2023, including its effect on MECL's planning estimate of peak load and its increased estimated need for on-island capacity supply in the face of a higher peak load. Based on the S&L analysis in the addendum, MECL recommended a higher amount of on-island capacity supply in the near term to maintain a target that would meet roughly 50 percent of the winter peak load with on-island supply.

The addendum reported on the peak load pattern during the 3-day period in February of 2023. It also included information on wind generation, temperature, and resource supply during the event. The addendum noted the reduction in performance for some of the wind generation resources during a portion of the event and described the reasons for the reduction. It noted a new maximum hourly peak load for the entire island of 395.7 MW at roughly 7 PM on the 4th of February and noted peak imports from New Brunswick of 290 MW at roughly 4 PM. While the extreme weather event was felt throughout the Maritimes and New England, the interconnection with New Brunswick *remained fully online* during the event.

Notably, the addendum included hourly information on PEI wind generation, wind speed, and temperature correlation during the event, in Figures 2-3 and 2-4. As noted below, in response to a Synapse information request, MECL provided additional information on the wind generation performance during the February 2023 event, as well as steps that have been taken, and can be taken, to improve wind generation performance during extreme weather events.

### Supplemental Budget Request August 2025

In August 2025, MECL submitted a Supplemental Budget Request offering an Accelerated Capacity Solution (ACS) consisting of 100 MW (two 50 MW units) of CT capacity from ProEnergy, a provider of refurbished CTs. The units would be installed at the Charlottetown Generating Station. The total estimated cost of the installation is $334 million, inclusive of $10 million in estimated transmission interconnection costs.[37]

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36 Capacity Resource Study, page 90, "The reason BESS was not included in the recommended portfolio was primarily because of two reasons. First, a BESS solution is not as effective as the other shortlisted technologies at helping Maritime Electric meet its three most critical needs. Secondly, a BESS solution is a higher cost option than the other shortlisted technologies."

37 Supplemental Request at page 6.

MECL states the ACS is "lower cost" relative to an alternative of two new GE LM6000 turbines, which would cost $350 million including interconnection costs.[38] MECL updates its net present value (NPV) analysis for the ACS, comparing the NPV of the ACS to capacity purchases from NB Power. MECL states that the present cost of the CT project including financing and fixed O&M costs estimated over a service life of 50 years is $412 million.[39] MECL compares this value to an NPV of $904 million of avoided costs it would incur from procuring the same capacity services from NB Power for 50 years.[40]

MECL does not compare either the installed cost or the NPV of the proposed ACS to any BESS alternative. MECL also does not explain why the RICE alternative considered as the primary resource in the Capacity Resource Study and proposed as the majority capacity supply component (90 MW of 150 MW total) in the December 2024 Application is not under consideration at this time. While MECL states that the ACS "is the most cost-effective option" at page 31 of the Supplemental Request, Table 5 in that document (page 32) shows a RICE installed capacity cost of $3,234/kW; this cost is slightly lower than the $3,240/kW cost shown for the ACS.[41]

The Supplemental Budget Request claims the ACS "represents the most cost-effective and viable path to securing new on-island generation capacity by 2028," and "is the only viable and cost-effective path…"[42]

### Project Update Submissions – April 2025 and October 2025

MECL submitted a project update in April 2025 illustrating a projected trend of increasing peak load with respect to temperature, because of the presence of increased heating loads associated with PEI's decarbonization policies (which support heat pumps to replace oil for winter heating needs).

MECL also submitted a project update in October 2025, following the technical conference. The update included material addressing the forced outage rates for the proposed CT project and explained that MECL would separately submit a revised application for additional capacity (the original application was for 150 MW; the August 2025 supplemental request was only for 100 MW) if the August supplemental application was approved.

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[38] The Supplemental Request, Appendix A, S&L letter of August 13, 2025, indicates a cost of $340 million, but MECL notes (at page 25) that the S&L values exclude the roughly $10 million for interconnection at the site. We add that $10 million to S&L's $340 million estimate to arrive at the $350 million value.

[39] Supplemental Request, Table 4, page 28.

[40] *Ibid*.

[41] MECL does not address either delivery timeliness for the RICE units, or suitability at the Charlottetown station; and thus the rationale for excluding RICE from consideration at this time is unclear.

[42] Supplemental Request, pages 5 and 29.

## Responses to Information Requests

MECL has responded to two sets of information requests (IRs) from Synapse (May 2025 and November 2025) and one set of requests from each of Chandler and Energy Storage Canada (May 2025).

### *New Brunswick Transmission Interconnection Disconnections*

MECL's response to Synapse's May 2025 IRs included detailed information concerning the incidences of partial and full New Brunswick transmission interconnection disconnection.[43] Since the installation of the second set of cables in 2017 there has been one incident of full disconnection; this was an 8.5-hour event during the November 29, 2018, winter storm.[44] The other three full disconnection incidents occurred in 2004, 2005, and 2007. Two of these lasted less than an hour, and the third lasted 2.5 hours. There has been no load loss associated with partial disconnections since the installation of cables 3 and 4 in 2017; load loss due to partial disconnection occurred only prior to 2017 when just two cables were in place.[45]

### *Wind Generation and Battery Energy Storage Performance in Extreme Weather Events*

In response to Synapse's IR-14 and IR-15 questions on wind generation performance during the February 2023 extreme weather event, MECL noted multiple solutions (either in place or pending) to performance issues concerning extreme cold, high winds, and grid stability. MECL states it is "satisfied that on-Island wind farm operators are taking positive steps towards increasing the reliability of on-Island wind production during extreme weather events." In addition, MECL notes that the new Eastern Kings Phase 2 project will have "significant improvement in extreme weather operation over the existing wind turbines on PEI." Further, based on information provided by wind farm operators during discussion at various times in 2023, 2024, and 2025, MECL states, "Most PEI wind farms are now believed to be well positioned to maintain operation during extreme cold weather events such as the February 3 to 5, 2023 polar vortex."[46]

In response to Synapse IR-13, MECL stated that "the addition of battery, wind, or solar generation resources is not expected to mitigate these concerns [e.g. power system support services including inertia, voltage support, short circuit supply, capacity reserve]," referencing the need for the transmission system to be energized. Synapse emphasizes in the Discussion section below that grid-

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43 Response to Synapse IR-8 (first set), Appendix A to the response.

44 Response to Synapse IR-8. Appendix A to the response includes a detailed description of the full and partial disconnection events. The November 29, 2018 full disconnection event duration was 8.5 hours per MECL's response (IR-8, a.ii.) though Appendix B to the IR-8 response includes a storm post-mortem report (January 21, 2019) with an Appendix A ("Summarized Sequential Event Log") that indicates a full disconnection of all four NB cables existed between roughly 8:54 AM through 4:12 PM (7 ¼ hours). The storm itself lasted roughly 24 hours, outages were caused by transmission and distribution system outages in addition to the loss of the interconnection, and all customers were in service by December 3, 2018.

45 Response to Synapse IR-8, Appendix A, pages 4-8.

46 MECL responses to Synapse IR-14 and IR-15 a, c, and d.

forming BESS resources *are* capable of providing such power system services and would directly support more effective utilization of on-island wind resources during a disconnection event.

MECL provided hourly load and supply resource data for the winter of 2024–2025 in response to IR-19. These data show the pattern of load and resource balance during the most recent winter peak period. Synapse uses these data in the following Section 3 to illustrate how a 6-hour BESS alternative would function during a winter peak period (using the 72-hour period from January 29–31, 2025, inclusive of the peak hour on January 30, 2025).

#### *Cost of Alternative Capacity Resources*

A key response to Synapse's second set of IRs from MECL in November 2025 concerned the cost of alternative capacity resources given different lifetimes for those resources. MECL provides a summary of costs in Table 1 of the letter prefacing the IR responses. As we explain in the Discussion subsection below, the capacity cost comparison presented in that table is incomplete and analytically flawed; it does not adequately describe relative costs between MECL's proposed CT project and a BESS alternative of similar scale (100 MW) over a consistent timeframe.

#### *Energy Price Arbitrage*

MECL also included a discussion on the energy arbitrage use case in the November 2025 letter prefacing its responses to Synapse's second set of information requests. MECL characterized the energy benefit available from price arbitrage of New Brunswick energy as limited, because of the average annual difference in on-peak to off-peak prices of $11/MWh for all of 2024, computed based on the relevant ISO NE New Brunswick energy pricing point.[47] However, MECL does not address the actual distribution of energy prices during the relevant periods in a winter season. There is a larger energy price differential for winter periods, which supports a net positive and significant energy benefit from the energy price arbitrage use case. We present this information in the Discussion subsection that follows.

As noted, we address the cost comparison and energy price arbitrage use case issues in our Discussion subsection below. We note that when the lifetimes of alternative resources are levelized, allowing for an apples-to-apples comparison across alternatives, the BESS resource alone, and certainly in combination with the net energy benefits that it will confer over its lifetime, continues to be a less costly capacity supply resource option than MECL's proposed CT project. We also show how the distribution of energy prices during the winter season will allow MECL to fully capture the energy benefits of price arbitrage using the BESS resource.

### Other Planning Factors

Other planning factors can affect consideration of the most prudent course for on-island capacity supply investment by MECL. Those factors include PEI's policy for reaching sustainability targets, the likelihood

[47] MECL response to Synapse IRs, November 12, 2025 letter preface, pages 2-3, "Use Case 1: Energy Arbitrage."

and timing of additional infrastructure investment such as the planned new 138 kV transmission line upgrading overall east-west transfer capabilities on PEI,[48] specific new wind project investment by PEIEC or others beyond the recently completed PEIEC Eastern Kings phase 2 project,[49] and the extent to which new demand-side resources can improve the ability to reduce peak load spikes during extreme winter weather periods.[50]

The third west-east transmission line considered in the ISP would improve overall PEI reliability though it is unclear exactly what the tradeoffs or substitution possibilities are between such a line, and the additional of new on-Island generation (or battery storage) capacity. While the ISP states "Need additional generation and/or a third west-to-east line in place" (page 87, ISP Appendix A), the ISP was not contemplating battery storage, as opposed to generation, located in the east. While it is possible that on-Island battery storage or generation at the Charlottetown site may reduce the need or the year-of-need for the line, we have not closely examined this aspect of MECL's planning as part of this report. We do note that having more reliable transmission transfer capability across the center portion of PEI extending from the Borden / Bedeque generation and cable landing areas through the load center of Charlottetown and towards the eastern end of PEI (with its connection to eastern wind resources) is reasonable in an era of increasing system loading.

## 2.2. Discussion and Critique

This section addresses the core issues considered by MECL in its Application and in the subsequent and related documents such as the S&L studies and the August 2025 Supplemental Budget Request.

We discuss and, where necessary, critique certain elements of the overall request by MECL to approve spending for 100 MW of new CTs, including the following:

- On-Island capacity supply need, use case, and reducing risk of New Brunswick energy import curtailment
- Cost of alternative options to the new CTs
- Timing of alternative options to the new CTs
- System energy considerations under different capacity alternatives, including New Brunswick energy pricing patterns and the value of energy and wind production arbitrage
- Resource performance under full or partial disconnection scenarios

48 MECL, Integrated System Plan, Table 31, Summary of Potential Capital Projects Post-2025.

49 MECL Application, Table 2, 106 MW of other new wind resources requesting interconnection. Page 22.

50 The newly installed AMI technology can help to enable additional demand response during extreme winter weather events.

- Synergies between BESS capacity resources and increasing amounts of wind on PEI to meet GHG and related PEI policies that would lower energy imports from New Brunswick
- Reliability and performance benefits of BESS and its ability to meet the “use case” needs required by MECL:
    - BESS grid-forming capabilities, including superlative ancillary service performance, to support on-Island use of wind during extreme weather events, and at 6-hour duration provide an even greater capability to reduce New Brunswick energy curtailment risk during extreme conditions
    - BESS capabilities to support even lower ongoing use of any diesel fuel consumption at existing CT resources by eliminating “hold to schedule” generation requirements from CTs

## On-Island Capacity Resource Need and Use Cases

### *On-Island Capacity Supply Need of 50 percent of Total Requirements Is Reasonable*

In recent past until 2022, MECL’s on-island dispatchable capacity has been about 50 percent of its peak load.[51] Historically, the remainder of capacity needs were procured as long-term or short-term firm capacity from NB Power as their legacy system provided such capacity at lower per-unit costs than new resources. MECL also has a 29 MW share of the Pt. Lepreau nuclear power plant capacity located in New Brunswick.

MECL recommends a target value of 50 percent of the capacity needs associated with projected winter peak load on its system, similar to recent historical trends. This includes the 15-percent reserve requirement above the forecasted normal winter peak load.[52] MECL notes that to maintain this level of on-island capacity as a percentage of winter peak load, additional on-island capacity will be required over time. MECL indicates that its original project capacity amount (the 150 MW value from its December 2024 application) is expected to bring 2033 on-Island capacity up to roughly 50 percent of PEI’s total capacity requirement.[53] The current proposal of 100 MW of CT resource would meet two-thirds of the on-island proportion of the capacity need.

MECL’s proposal to increase the amount of on-Island capacity to approximately 50 percent of its total capacity needs, with roughly two-thirds of that coming online in the near term (by the end of 2028) is reasonable. The rising cost of capacity purchases from NB Power, coupled with the decline of existing

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[51] Capacity Resource Study, page 9, page 16. It was 49% in 2020; and averaged 60% for the 2015-2019 period. These values are a share of peak load excluding the additional 15% capacity requirement for reserves shown in Table 9 of the Application.

[52] MECL, response to IR-7 b.

[53] Application, Figure 20 (page 70) and Table 10 (page 45), showing on-Island capacity of roughly 50% of 2033 capacity requirement (Table 10, 229 MW / 454 MW = 50.4%). On-Island: 30+49+150=229 MW.

on-Island resources and increasing peak load levels, supports MECL's proposal to increase on-Island resources. However, while the target of approximately 50 percent is reasonable, the exact timing and total magnitude of on-Island capacity does not reflect a hard constraint imposed on MECL because even in the event of extreme weather events, the set of interconnecting cables continues to be a reliable source for capacity and energy.

The scale and timing of the proposed on-Island capacity increase increment is thus reasonable, even though by itself it falls short of MECL's 50% on-Island target capacity balance projection for 2033, after the Borden units retire. It remains reasonable to procure a first increment of roughly 100 MW as the Application currently considers; without considering reserve needs, and using MECL's updated forecast (Application, Table 9), this leads to an on-Island dispatchable share in 2028 of 189/355 = 53%, and with planning reserves the value is roughly 189/408 = 46%.

*Total* on-Island capacity shares are higher when including the 30 MW of wind "effective load carrying capacity" (ELCC);[54] respectively, 62% (peak only) and 54% (peak + reserve requirement) from Table 10 of the Application. The loss of the Borden CTs after 2032 further reduces this share, as does peak load growth; to maintain a pace towards the 50% target, a second round of on-Island capacity procurement would be necessary for installation by roughly 2032, as the Borden CTs are retired, to both compensate for their loss, and to make up the remaining roughly 50 MW of targeted on-Island supply.

MECL can and should continue to procure lower-cost firm capacity from NB Power for as long as it is available; and MECL will need to access short-term firm capacity as it is available.[55] While the application indicates 190 MW of long-term firm capacity is available through 2026, MECL assumes firm capacity beyond the 190 MW is not available after 2026. This implies that in the interval period from 2027 through the time at which new on-Island capacity is secured, MECL will be at some risk of firm capacity shortages and thus will be at some risk of energy shortages. This is the "curtailment risk" MECL identifies in its application.

While the goal of increased on-Island capacity is reasonable, procurement of additional firm capacity from NB Power would help meet near-term capacity needs. It is reasonable for MECL to determine if NB Power firm capacity increments exceeding 190 MW after 2026 are potentially available, if only to mitigate capacity concerns until the new alternative on-Island capacity is operating. Additional increases beyond the 190 MW, if available, are not unreliable, since the interconnection itself is rated at 300 MW of firm capacity. It would be reasonable to keep such increases to a minimum to stay close to the target:

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[54] ELCC is defined, in short, as the 'resource adequacy' value attributable to a resource. It recognizes that a resource's nameplate MW rating cannot always be fully counted on to be available during the times when resources are most necessary, which is usually during peak load periods. Probabilistic assessments of the pattern of a resource's output during key peak periods are completed to gauge what percentage of the nameplate capacity can be relied upon. For existing MECL wind on PEI, MECL uses an ELCC value of 23%, or they count 21 MW of their 92.5 MW wind resource. This percentage value would decline over time as more wind comes online. MECL estimates that if 70 MW of additional wind were included in their portfolio, the ELCC share will decline to 17%. CRS, page 62.

[55] See, e.g., Application at page 20 and footnote 29, indicating that "to date, NB has had excess capacity available and has allowed the Company to purchase additional capacity on a short-term basis to meet the Company's capacity requirements."

for example, up to 210 MW of long-term capacity import, coupled with the 29 MW share from Pt. Lepreau leads to a total on-Island winter peak capacity share in 2033 of 47.4% (1 minus 239 MW/454 MW), reasonably close to the 50% target presuming Borden replacement with on-Island capacity. There would be minimal reliability or operational constraints associated with such purchases, as NB Power would only sell such resources if they were available, and the interconnection itself can support it.

Over the medium-term time frame (e.g., early 2030s), if - or as - additional wind resources are placed in service, additional rated firm capacity from such wind would reduce the amounts needed from New Brunswick and bring the on-Island total share back to or above 50%. Any further increments of demand-side peak load reduction (not included in Table 9, and potentially available once programs are in place) would also effectively increase the on-Island capacity share. We note that Table 10 in the Application *excludes* the capacity contribution that would come from increments of wind beyond the Eastern Kings Phase II project. The increase from the 106 MW of additional wind represented in the Application at Table 2 (Skinner's Pond, and Bedeque) would be roughly in the range of 10-20% of the nameplate capacity depending on an ELCC analysis, allowing for a reduction in NB capacity imports of that amount at the time of the wind plant's operation.

***Use Cases Support CT and BESS Resource Alternatives***

The Executive Summary of S&L's Capacity Resource Study sets out MECL's on-Island capacity supply needs: (1) meet energy and capacity obligations, (2) improve load service during electrical disconnection from the mainland, and (3) achieve sustainability targets.

In response to IR-2 of Synapse's second set of interrogatories, MECL confirmed that the use case for the on-island capacity supply need is seen in its December 2024 Application at page 13:

> "This capacity will primarily serve as peaking and backup capacity for responding to unplanned system events, hold-to-schedule directives from NB Power and facilitating planned maintenance activities. The project will reduce the need for off-island capacity purchases, which is expected to provide overall savings of approximately 20 percent over its useful life. The project is also expected to support additional renewable energy development on PEI and enhance the reliability and security of electricity supply to customers."

MECL also notes additional use cases or operational and reliability considerations, "that have become increasingly relevant in the context of Prince Edward Island's capacity deficit and the broader energy transition" and lists three further cases (including the second element listed in the Executive Summary of the Capacity Resource Study): (1) improved load-serving capability during disconnection events, (2) synchronous condensing operation for voltage support, and (3) transmission contingency support during high load conditions. MECL also emphasized during the September technical conference that reducing the risk of curtailment of energy imports from New Brunswick during extreme events was also of paramount importance.[56]

CTs and BESS resources both serve as "excellent" capacity resources.[57] Both meet the primary use case elements and the additionally considered elements 1–3 listed above. While MECL has not distinguished between use case needs during "partial" disconnection, vs. "full" disconnection, both CTs and BESS resources provide support during either a full or a partial disconnection.

S&L notes in the Capacity Resource Study that, "[a]t best, a BESS system could be very helpful for Maritime Electric during a disconnection from the mainland; however, if the wind power plants are not generating electricity during the time when PEI is disconnected from the mainland, then the amount of support a BESS could provide is limited to both its state of charge and duration."[58]

We note that the higher likelihood for disconnection occurs during extreme winter weather. In PEI, winter represents times when there is a higher likelihood of relatively high performance for wind resources, especially over the course of the entirety of a winter day. Also, as we show in our example in Chapter 3, wind power plants on PEI are not the only source available to ensure a BESS resource would be fully charged in anticipation of extreme system conditions. Energy imports from New Brunswick as available outside of the highest load hours can be used to ensure high availability of the BESS resource during critical periods.

Thus, a large-scale BESS resource, such as 100 MW, is a viable alternative that meets MECL's use case needs. Whether a four-hour or a longer period BESS resource such as six-hours is needed depends on the amount of risk curtailment MECL seeks with a capacity option. Grid-forming BESS resources can provide the ancillary service support necessary during even a full disconnection event. The state of charge of BESS resources can be managed by MECL and NB Power, especially under conditions where there is a greater possibility of disconnection during extreme weather events.[59] As we show in Chapter 3, and in the following subsection, a clearer cost comparison between the CT alternative and a similarly-sized BESS alternative is required to demonstrate which option has better cost-effectiveness for the use cases under consideration.

As noted, both CT resources and BESS resources are "excellent capacity" resources, according to S&L's Capacity Resource Study.[60] However, MECL in its application does not recommend additional BESS

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[56] This is also noted at page 68 of the Application, where MECL lists as part of "Project Justification" elements "limit exposure to Interconnection transfer limitations or curtailments from the NB system, which is a reliability benefit for customers".

[57] S&L Capacity Study, Table 5-9, page 76.

[58] Capacity Resource Study, pages 69-70.

[59] MECL had notice and was able to take steps to posture its system prior to the February 3-5, 2023, event, such as ensuring the CT resources were online. S&L, *Extreme Weather Event, Capacity Impact* report, July 12, 2023, page 8.

[60] Capacity Resource Study, Table ES-3, page VII and Table 5-9, page 76.

capacity because it states that "…the system peak reduction capabilities of a BESS are limited."[61] Synapse disagrees with the assertion that a larger-scale BESS resource is not an acceptable capacity alternative to the proposed 100 MW CT project, because of MECL's premise that a BESS resource's "system peak reduction capabilities are limited."[62] MECL fails to provide comprehensive analytical support and context for its levelized load example, or fulsome cost analysis in drawing its conclusion.[63]

MECL focuses on the capabilities of BESS resources and uses the February 4, 2023, peak day to illustrate, with an academic exercise, that BESS resources on their own (absent any consideration of the status of other supply resource availability, on- or off-Island) achieve a "maximum system peak reduction…" of 32 MW, requiring BESS energy storage of at least 262 MWh.[64]

The implication of this example is that a 32 MW battery with 8.2 hours of storage capability (262 MWh) would be needed to levelize the load on this extreme peak day. MECL also states that "increasing system peak reduction from 20 MW to 30 MW using a BESS requires a significantly larger BESS (167 MWh compared to 66 MWh) and the BESS cost would more than double."[65] However, the example does not provide any information about how the presence of a BESS resource under these conditions would affect MECL's and NB Power's approach to maintaining resource adequacy and minimizing any need to curtail required energy imports to PEI. Thus, the example requires further context and the premise requires closer examination.

MECL presents this example without considering the status and patterns of other available supply resources (on-Island or off-Island) for February 4, 2023 (or for the February 3-5, 2023, 72-hour period depicted more fully in the S&L addendum to the Capacity Resource Study, from July 21, 2023). MECL's lack of consideration of how the BESS resource and other supply resources would function (and be dispatched in real time) on a peak winter day is an analytical shortcoming. This shortcoming leads to a flawed conclusion that a large-scale BESS would not be a reasonable or cost-effective option to meet the needs of the day. As we illustrate in an example in Chapter 3, the BESS resource leverages the other supply resources (namely,  on-Island wind and off-island energy flows as available from NB Power) to support a much-reduced risk of potential curtailment of NB energy due to tight off-Island supplies, even if it is not otherwise able to "levelize the load."

The purpose of a BESS alternative for capacity support on-Island is not to levelize the load over the course of a peak winter day (although that is likely an artifact of its operation), but to allow MECL and NB Power to optimize its use (i.e., when it is charged and when it is discharged). The optimization would aim to fully leverage both on-Island wind resource availability and off-Island energy import availability

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[61] Application, Section 8.3.

[62] Application, page 113.

[63] Application, Section 8.3, including Figure 29 and Table 21, pages 113-115.

[64] Application, pages 114-115.

[65] Application, page 114.

(while considering other system reliability factors) in such a way as to minimize curtailment risk for energy flows if the NB Power system is short (or potentially short) on capacity that day. Neither MECL nor S&L consider a BESS capacity resource in the context of its fully leveraging the availability of other supply resources over the course of an entire winter peak day (or event period) to mitigate the risk of a curtailment event if NB Power has insufficient capacity during certain hours of the day.

S&L's Extreme Weather Event Capacity Impact report presents the February 3-5, 2023, event period in more detail than is seen in MECL's Figure 29 and Table 21 of the Application. The report reveals critical information concerning the performance (or lack thereof) of wind generation during that period. The report's Figures 2-3 and 2-4 are particularly valuable in that they show that (1) wind speeds remained high even though some turbines performed poorly, and (2) wind generation during the earlier part of the period was particularly high, with total peak wind generation reaching 160 MW on the afternoon of February 3, 2023. Subsequent to this event, MECL confirmed that the performance ability of those generators that exhibited poor performance during the colder portion of the event[66] has since improved due to initiation of mitigation measures.[67]

The lessons learned from considering events on February 3-5, 2023, and considering what might occur on future winter peak days with improved wind resource performance are insightful. The data for that period show a correlation between the availability of wind power and low temperatures that drive increases in peak load. It also shows high wind resource output during an extremely cold day.[68] The presence of the wind resource (with improved performance attributes for existing resources, and assumed high performance in cold weather for new resources), if coupled with the presence of BESS resources, would provide MECL and NB Power considerably more flexibility to reliably dispatch on-Island resources and secure off-Island energy to meet load while minimizing any need to potentially curtail energy flows to the Island.

Chapter 3 of this report presents an illustrative example of BESS output patterns and system impacts during a winter peak day, using data from the 72-hour period from January 29-31, 2025, and assuming the presence of a 6-hour duration 100 MW BESS resource. It shows how a BESS resource would operate in consideration of both the available wind on PEI, and the available flow limits that may be in place between New Brunswick and PEI during that period. The example's purpose is to illustrate the viability and effectiveness of a BESS resource, in place of a new 100 MW CT resource, in meeting hourly energy needs during a winter peak day while respecting wind output patterns and import constraints between PEI and New Brunswick.

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[66] The colder portion of the event was during February 4, 2023, when temperatures were low and wind speeds were high, but wind output was low due to non-performance.

[67] MECL response to Synapse IR-14 and IR-15, May 2025.

[68] See Figures 2-3 and 2-4, page 10, of the S&L *Extreme Weather Event Capacity Impact* report.

## Comparative Installed and Net Present Cost of 100 MW CT Project and 100 MW BESS Alternative

### *Installed-Cost Comparison*

MECL has provided multiple estimates of the installed cost for CT, BESS, and RICE capacity alternatives. Some of the costs have changed considerably since the Capacity Resource Study was completed in December of 2022. MECL also provided net present cost information in the Application and provided the underlying net present cost formulations (in response to interrogatories) used to compare the proposed capacity solution costs relative to continuing capacity procurement from NB Power. Net Present Cost represents the costs accounting for financing costs, ratemaking protocols, and the time value of money (using MECL's weighted average cost of capital, 6.69 percent).[69]

We examine those costs and discuss MECL's methodologies for comparing capacity costs between CT and BESS resources in this and the following section. First, Table 1 below contains the cost estimates provided across MECL's submittals in this matter. Table 1 also contains two cost estimates from Synapse for larger-scale (100 MW, vs 50 MW) BESS resources based on MECL's underlying estimates for the 50 MW scale BESS resource. MECL did not explicitly provide any cost estimates for a 100 MW scale BESS resource alternative, and thus use of the per unit cost for a 50 MW resource may fail to capture economies of scale that could be obtained with a 100 MW BESS resource. If captured, those economies of scale could result in even lower per-unit costs for the 100 MW BESS resource than shown here.

[69] See Appendices E and F to MECL's Application, and the confidential spreadsheets provided in response to those appendices which contain the formulations used to compute net present cost.

**Table 1. Comparative Installed Cost**

| Capacity Resource | CRS Study December 2022 Installed Cost per Unit | Extreme Weather Event Capacity Impact Report July 2023 Installed Cost per Unit | Application, December 2024 Installed Cost per Unit | Application, December 2024 Tot. Installed Cost Tot. PresValue (PV) Cost, $ millions | May 2025 IR Responses | Aug. & Nov. 2025 MECL estimate / CT & 50 MW BESS<br>___________<br>Synapse Estimate for 100 MW BESS | Inteconnection, $/kW, at Charlottetown site (based on 100 MW) | Estimated Installed Cost – 100 MW Nameplate including interconnection, $ millions | Notes/Source |
|---|---|---|---|---|---|---|---|---|---|
| RICE - diesel 53 MW | $2,257/kW | | | | | | | | CRS, Table ES-3 and 5-9 and Appendix A |
| RICE - diesel 90 MW | | | $2,711/kW | 244 (installed)<br>315 (PV) | $3,234/kW | | | | Application, Table 13 (p62), Response to Synapse IR-12 b. May 2025. |
| RICE - diesel 148 MW | | $1,845/kW | | | | | | | July 2023 Report Table ES-1, Table 5-1, Appendix A |
| CT - diesel 73 MW | $2,486/kW | | | | | | | | CRS Table ES-3 and 5-9 and Appendix A |
| CT - diesel 50 MW | | | $3,120/kW | 156 (installed)<br>193 (PV) | $3,871/kW | | $100/kW | $397.1 | Application, Table 13 (p62), Response to Synapse IR-12 b. May 2025 |
| CT - diesel - 171 MW | | $1,744/kW | | | | | | | July 2023 Report Table ES-1, Table 5-1, Appendix A |
| CT - diesel - 100 MW | | | | | | $3,240/kW | $100/kW | $334.0 | August 2025 Supplemental Request |
| BESS – 4 Hour 10 MW | | | $2,664/kW | 27 (installed)<br>32 (PV) | $2,670/kW | | | | Application, Table 13 (p62), IR-12c response |
| BESS – 4 Hour 50 MW | $2,670/kW | | | | $2,234/kW | $2,710/kW | $100/kW | | Synapse IR-12 c. May 2025<br>Table 1, preface Nov. 2025 response. |
| BESS - 4 Hour 100 MW | | | | | | $2,234/kW | $100/kW | $233.40 | Synapse based on MECL May 2025 IR-12 b. response |
| BESS - 6 Hour 100 MW | | | | | | $3,038/kW | $100/kW | $313.80 | Synapse based on 1.36 NREL multiplier to 4-Hr cost estimate |

*Source: All resources except 6-hour BESS: Synapse compilation from MECL sources as noted in table. 6-hour BESS: Synapse, based on NREL 1.36 multiplier for 6 vs. 4 hour BESS. https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.*

Table 1 above shows increasing per unit costs for CT and RICE resources considered by MECL, between the time of the Capacity Resource Study submittal in 2022, the original project Application from December 2024, and then again during 2025. Cost increases for fossil resources are due to the ongoing supply constraints for such resources in the face of increasing demand.[70] The 2025 cost updates include those provided in May 2025 in response to Synapse interrogatories and current estimates for the ACS project cost submitted in the August Supplemental Budget Request and in the preface to the November 2025 response to Synapse's second set of IRs.

Table 1 above also shows flat and declining 4-hour duration BESS resource costs. Recent cost decreases and continuing projections of cost decreases for BESS resources stem from ongoing technological improvements in the resource base.

Review of the cost data highlights several key elements:

- The current per-unit costs ($/kW installed) of BESS resources are considerably less expensive than the per-unit costs for the CT or RICE resources. This is true even for the longer-duration storage (6 hour) BESS resources. This was not the case in 2022.
- There have been large changes in cost for CT and RICE resources since the initial 2022 Capacity Resource Study estimates. This is critical; fossil-based capacity costs have increased dramatically due to market pressures, while BESS costs continue to fall. MECL has not directly addressed this market and cost dynamic.
- MECL noted costs for 50 MW BESS of $2,234/kW in its May 2025 response; but in the November 2025 preface, MECL used $2,710/kW for 50 MW BESS. A 100 MW BESS unit could have additional economies of scale, lowering the per-unit costs.

Notably, in the 2022 Capacity Resource Study (Application, Appendix C) Final Recommendations section, S&L did not include a direct cost comparison between its preferred Portfolio D and the other portfolios considered (A, B and C, or any other portfolio option) even though the report explicitly notes that its portfolio recommendation "most cost-effectively" meets MECL's needs.[71] Based on MECL's response to IR-3 a, which asked what metrics were used to compare cost-effectiveness in support of its recommended portfolio, it appears S&L used capital and fixed O&M costs in support of the "most cost-effectively" assertion for the CT/RICE combination.[72] However, while per-unit costs for CT and RICE

[70] See MECL Application, page 128, "The factors that will influence the estimated impact on rate base, revenue requirement and customer rates include: …the impact of CT and RICE equipment market pricing dynamics *in a period of high demand*", and Supplemental Budget Request, page 8, "These increases reflected power generation market conditions in May 2025 and were based on similar equipment configurations and contingency allowances. *Currently, the power industry continues to experience upward cost pressures due to high demand for generating equipment*". [*emphases added]*

[71] Capacity Resource Study, Section 6.3, Final Recommendation, page 89.

[72] MECL, response to Synapse IR-3 a (first set), "The [Capacity Resource Study] evaluated capital and fixed O&M costs of generation and storage resources to compare portfolio options."

alternatives were lower than those for BESS options in 2022, that is no longer the case, as seen in Table 1.

In its December 2024 Application, MECL compares its preferred project cost to the cost of procuring capacity from New Brunswick, but it does not compare the cost to any other capacity supply alternative. MECL further states in the August 2025 Supplemental Budget Request that its proposed 100 MW CT accelerated capacity solution (ACS) from ProEnergy is "lower cost" than the prior estimate of per-unit CT costs provided by S&L for two 50 MW GE CTs. But again, MECL does not compare the ProEnergy costs to the costs of a 100 MW BESS resource. MECL asserts that the proposed ACS project is least-cost, but neither its Capacity Resource Study nor the December 2024 Application provides any direct cost comparisons to a BESS alternative of similar scale.

As Table 1 above shows, based on current market economics the BESS resources, even at a 6-hour duration, are less expensive than the CT resources on both an installed cost basis and a net present cost basis.

Next, we review resource lifetimes, net present costs, and related revenue requirement considerations to compare the economic cost of alternatives on a level playing field. We address the different lifetimes used by MECL (50 years for CT and RICE, and 20 years for BESS) and how to appropriately account for those differences (sustaining capital costs including augmentation needs in year 21–50 for BESS resources) when considering which alternative is more cost-effective for ratepayers.

***Net Present Value and Net Present Cost Comparisons Between Resource Options***

In the preface to its response to Synapse's second set of information requests in November 2025, MECL includes Table 1 ("MECL Table 1"), labeled as "Capacity Cost Comparison for BESS ELCC Scenarios" (shown below).[73] MECL Table 1 presents BESS capacity resource alternatives with a 20-year useful life, and the CT option with a 50-year useful life. This table is the only place where MECL provides a direct capacity cost comparison between the proposed CT project (ACS) and an alternative BESS resource of similar utility scale,[74] but the comparison does not first consider the costs for a 50-year BESS option.

Using a 50-year useful life assumption for one resource option (the proposed CT) and a 20-year useful life assumption (for the 4-Hr BESS) for the purposes of calculating a Present Monthly Capacity Cost—as MECL does in MECL Table 1—results in distorted cost results. Although BESS resources are often assumed to have a 20-year useful life, the investment in the balance of plant infrastructure will result in

[73] "ELCC" is effective load-carrying capacity.

[74] However, MECL does not capture potential economy of scale effects on the BESS resource cost in MECL Table 1. The per-unit cost in MECL Table 1 is higher than MECL indicated for a BESS resource (including interconnection costs) in its response to Synapse IR-3 (1st set), at $2,710/kW ($135.5 million/50 MW), vs. $2,334/kW. The BESS cost from MECL's response to IR-3 is $2,234/kW plus the cost of interconnection, or $100/kW (e.g., for a 100 MW interconnection at the Charlottetown plant site), totaling $2,334/kW.

value beyond the 20-year life. Estimating the costs of an increased useful life of 50 years for the BESS resource allows the economics of the CT and BESS resources to be directly compared to each other.

Synapse estimated these life extension costs by including sustaining capital in the years 21–50 (to allow for battery augmentation to offset degradation, and other sustaining capital if or as needed) which allows comparison of the CT and BESS resources to gauge relative cost-effectiveness. We show that in this section. Confidential Appendix A contains the NPC computation details, based on the structure of MECL's Confidential Appendix E to its Application.

**Figure 1. Image of MECL Table 1—Presentation of Capacity Cost Comparison for BESS vs. CT**

**TABLE 1**
**Capacity Cost Comparison for BESS ELCC Scenarios**

| | | Accelerated Capacity Solution | 4-Hour BESS High ELCC | 4-Hour BESS Medium ELCC | 4-Hour BESS Low ELCC |
|---|---|---|---|---|---|
| Nominal Capacity (MW) | A | 100 | 50 | 50 | 50 |
| ELCC (%) | B | 100 | 100 | 75 | 50 |
| ELCC (MW) | C = A x B | 100 | 50 | 37.5 | 25 |
| Useful Life (years) | D | 50 | 20 | 20 | 20 |
| Installed Cost ($ x 1,000) | E | 334,229 | 135,523 | 135,523 | 135,523 |
| **Present Costs** | | | | | |
| Present Cost ($ x 1,000) | F | 411,757 | 158,684 | 158,684 | 158,684 |
| Equivalent Annual Cost ($ x 1,000)[a] | G | 8,235 | 14,620 | 14,620 | 14,620 |
| **Present Monthly Capacity Cost ($/MW-yr)** | **H = (G x 1,000) / C** | **82,350** | **292,400** | **389,867** | **584,800** |

*Source: MECL Preface to responses to Synapse Second Set of Interrogatories, November 12, 2025.*

MECL Table 1 in its response preface shows installed costs for its 100 MW ACS of $334 million ($3,340/kW) and installed costs for a 50 MW BESS resource of $135.5 million ($2,710/kW, equivalent to $271 million for a 100 MW BESS). The present cost of the CT resource is $411 million, which is far greater than the $271 million present cost for a 100 MW BESS resource.

In this same table, MECL presents a "Present Costs" (Present Cost, and Equivalent Annual Cost rows) and concludes with a "Present Monthly Capacity Cost ($/MW-yr)"[75] listing in the table. In the text, MECL states that "the present monthly capacity cost of the BESS ($24,366/MW-month) is over three times more expensive (as a capacity resource) than the proposed Accelerated Capacity Solution ($6,863/MW-month)."[76] While MECL shows most of its computational steps in the table, it is unclear how MECL computed the "Equivalent Annual Cost" for the three 4-Hour BESS resources listed in the table. While the ACS value (8,235 in $'000) is seen to be equal to the Present Cost divided by the useful life ($411.8 million / 50 years), the same computation for the BESS resource entries does not yield the $14,620 value

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[75] While this is listed as a monthly cost, the numerical values listed are in $/MW-yr, not $/MW-month terms.

[76] Preface to the response to Synapse's second set of IRs, page 5, "Capacity Cost" paragraph.

(in $’000) seen in the table (158.7/20 years = $7,934). This inconsistency requires an explanation from MECL.

The conclusion that MECL draws—that a BESS resource as a capacity supply solution is more than three times more costly than the ACS—is inaccurate, when considering the value a BESS resource has after year 20. A BESS alternative (and certainly a 100 percent ELCC BESS resource) is not three times more expensive as a capacity resource than the proposed ACS, as we show in the Table 2 below. Separate from the unclear computation in MECL Table 1, the methodology MECL uses to draw this conclusion does not account for the significant BESS capacity resource value at the end of the 20-year lifetime assumed for the asset.

Synapse conducted an analysis of an extension of the BESS resource lifetime with sustaining capital and storage module augmentation investment for years 21–50 to allow its costs to be directly compared to the ACS costs.

Table 2 below shows the installed costs and the net present costs for the ACS option and 50-year useful life BESS alternatives. It shows the values used in MECL Table 1 in the IR response, as a comparison point. The calculation of the Net Present Cost for a 50-year BESS resource uses three different potential approaches to estimating the costs of extending the life of the BESS resource from 20 to 50 years:

1) Continuing augmentation every five years at years 21, 26, 31, 36, 41, and 46, at one-half the amount used by MECL in year 11 (which was a 10-year augmentation);
2) Replacement capacity at year 21 and year 41, at the full cost of a 100 MW BESS resource, amortized as 20-year assets, and assuming that roughly one-half of the capital asset needs replacement.[77]
3) Replacement capacity at year 21 and year 41, at the full cost of a 100 MW BESS resource, amortized as 20-year assets, and assuming that 100 percent of the capital asset needs replacement.

In both “replacement” approaches (2 and 3 above), the nominal cost of the BESS resource is estimated using The U.S. National Renewable Energy Laboratory’s (NREL) 2025 Annual Technology Baseline (ATB) estimation of the continuing trend of downward real costs for BESS assets.[78] Effectively, the real cost trends offset inflation such that the nominal costs are roughly the same as seen in the initial 20-year lifetime and amortization.

[77] NREL, *Cost Projections for Utility-Scale Battery Storage: 2025 Update*. Figure 1, page 6, shows the components of cost associated with a utility-scale battery energy storage system. The energy storage modules make up roughly one-half of the total capital cost of the initial investment. Augmentation is only required for the energy storage modules. Available at https://docs.nrel.gov/docs/fy25osti/93281.pdf.

[78] Ibid., at Appendix, Table 2, pages 16-17.

Costs for a 6-hour BESS resource, extended to a 50-year lifetime are also shown, using equipment capital costs that are roughly 1.36 times as costly as the 4-hour resource, based on NREL ATB's estimation for the increase in cost for a 6-hour vs. a 4-hour BESS resource.[79]

This approach puts the BESS capacity resource option on the same useful life footing as the ACS to allow an apples-to-apples cost comparison. A 6-hour BESS resource option is also shown. As seen in the rows at the bottom of Table 2, the Present Value Cost for the options is less expensive for the BESS resource in seven of the 10 scenarios listed:

- Assuming an ELCC of 1.0, all four BESS scenarios (three life-extension cost approaches for the 4-hr resource, and one for the 6-hr resource) have a less expensive capacity cost per month than the ACS.
- Assuming a 0.9 ELCC factor for the 4-hr battery resources, two of the three life-extension cost scenarios show a lower cost BESS resource than the ACS. Only the most expensive estimate (assuming full BESS replacement at year 21 and 41) is more expensive than the ACS ($6,953/MW-mo. vs $6,863/MW-mo), by 1.3 percent.
- Assuming a 0.75 ELCC factor for the 4-hr BESS, one of the three approaches to augmentation is less expensive than the ACS, and other two are more expensive.

In all cases, the ELCC of the ACS solution is estimated at 1.0, although CT resources exhibit forced outages that can lower their "effective ELCC" to less than one.[80]

In all cases, we assume a 6-hour BESS resource would exhibit a 1.0 ELCC factor.

In all cases, no additional energy premium benefit is considered for the BESS resource option, which would further improve the overall economics of these options.

The detailed cost schedules underlying this table, based on the structure provided by MECL in its Appendix E to the Application, are contained in Confidential Appendix A of this report.

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[79] NREL 2024 ATB, Utility-Scale Battery Overnight Capital Costs. The cost increase is less than 1.5 because only the energy storage component of the BESS resource is scaled up for the 6-hour duration battery; the power components (e.g., for a 100 MW inverter) are the same size and cost for the 6-hour resource as for the 4-hour resource.

[80] For example, some jurisdictions consider a CT resource having a resource adequacy value of roughly (1-EFORd), or 1 minus its forced outage rate. This would imply, for the ACS, an ELCC closer to .95 than 1.0.

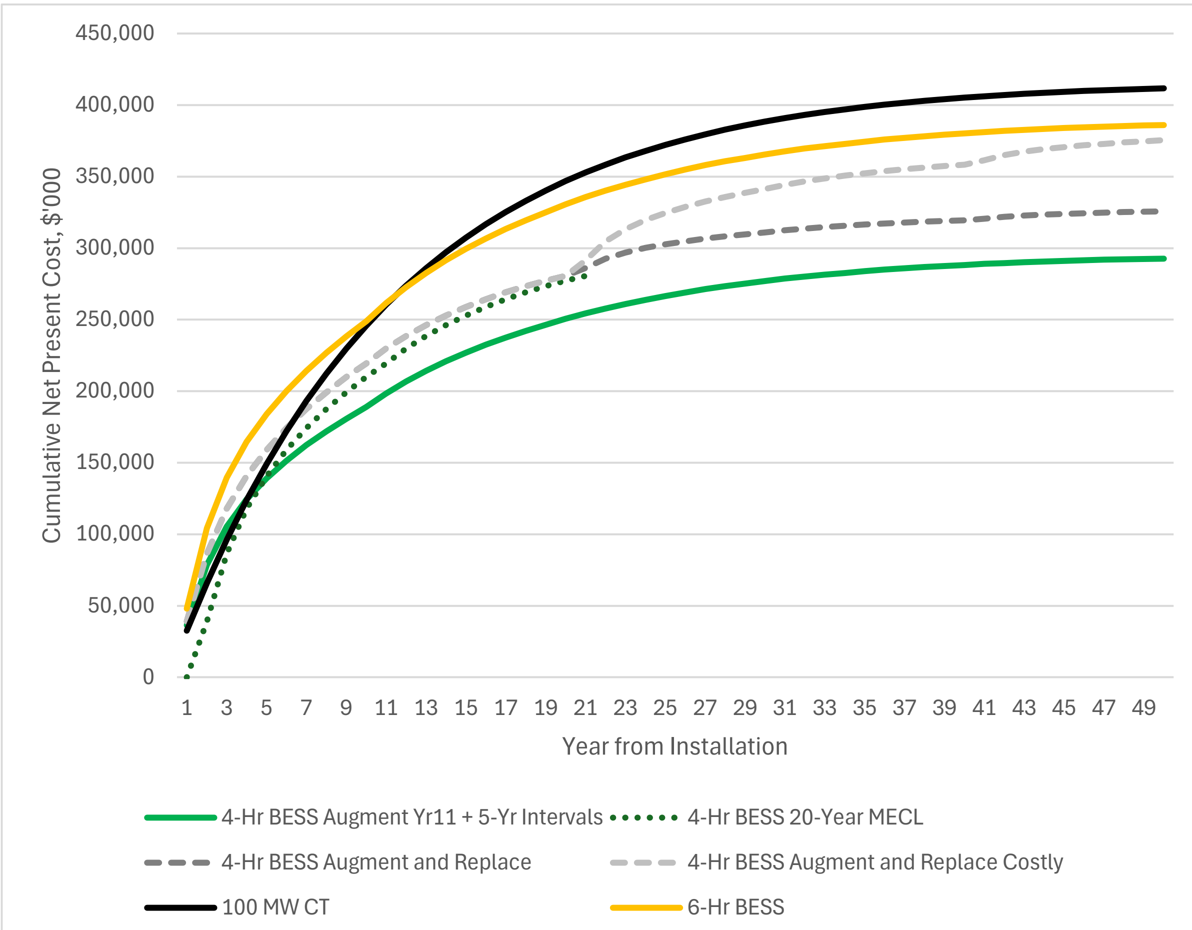
**Table 2. Cost Comparison, 100 MW CT (ACS) vs. 100 MW Battery Energy Storage System (BESS)**

| | MECL Table 1 and Text* | | | | Synapse** | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | ACS 50 years | 4-Hour BESS 20 Years | 4-Hour BESS 20 Years | 4-Hour BESS 20 Years | 4-Hour BESS 20 Years | 4-Hour BESS 50 Years Augment 1 | 4-Hour BESS 50 Years Augment 2 | 4-Hour BESS 50 Years Augment 3 | 6-Hour BESS 50 Years | Note |
| Nameplate MW | 100 | 50 | 50 | 50 | 100 | 100 | 100 | 100 | 100 | |
| ELCC | 1 | 1 | 0.75 | 0.5 | 1 | 1 | 1 | 1 | 1 | |
| Resource Obligation MW | 100 | 50 | 37.5 | 25 | 100 | 100 | 100 | 100 | 100 | |
| Useful Life, years | 50 | 20 | 20 | 20 | 20 | 50 | 50 | 50 | 50 | |
| Installed Cost per Unit, $/kW | 3,342 | 2,710 | 2,710 | 2,710 | 2,334 | 2,334 | 2,334 | 2,334 | 3,138 | MECL |
| Installed Cost, $'000 | 334,229 | 135,523 | 135,523 | 135,523 | 233,400 | 233,400 | 233,400 | 233,400 | 313,800 | 100 MW BESS cost 2,240/kW – MECL IR response (May 2025) |
| Net Present Cost, $'000 | 411,757 | 158,684 | 158,684 | 158,684 | 280,672 | 292,747 | 325,772 | 375,450 | 386,121 | Extending lifetime with capital investment / augmentation years 21-50. |
| MECL Equiv. Ann. Cost, $'000 | 8,235 | 14,620 | 14,620 | 14,620 | NA | NA | NA | NA | NA | MECL stated Table 1 |
| MECL Present Annual Capacity Cost, $/MW-yr | 82,350 | 292,400 | 389,867 | 584,800 | NA | NA | NA | NA | NA | MECL stated Table 1 |
| MECL Present Monthly Capacity Cost, $/MW-month | 6,863 | 24,366 | NA | NA | NA | NA | NA | NA | NA | MECL stated Table 1 |
| Computed Equiv. Ann. Cost = NPC/Useful Life | 8,235 | 7,934 | 7,934 | 7,934 | 14,034 | 5,855 | 6,515 | 7,509 | 7,722 | Synapse computed. |
| | | | | | | | | | | |
| Computed Present Annual Capacity Cost, $/MW-yr | 82,351 | 158,684 | 211,579 | 317,368 | 140,336 | 58,549 | 65,154 | 75,090 | 77,224 | Synapse computed. |
| Computed Present Monthly Capacity Cost, $/MW-month | 6,863 | 13,224 | 17,632 | 26,447 | 11,695 | 4,879 | 5,430 | 6,258 | 6,435 | Synapse computed. |
| Computed Present Monthly Capacity Cost, $/MW-month | | | | | At ELCC=.9: | 5,421 | 6,033 | 6,953 | | Synapse computed. |
| Computed Present Monthly Capacity Cost, $/MW-month | | | | | At ELCC=.75: | 6,505 | 7,239 | 8,343 | | Synapse computed. |

*Notes: *MECL Table 1 and text from preface to response to Synapse second set of IRs, November 2025. **Synapse estimates for BESS installed costs from MECL response to IR-12 c. (May 2025). Synapse estimates of NPC based on additional capital expenditure and augmentation costs for years 21-50. NPC computations for 50-year BESS useful life based on structure of MECL's Appendix E and listed in Confidential Appendix A to this report. Three approaches to augmentation / additional sustaining capital shown. All values exclude energy effects and exclude the savings (avoided costs) from lower capacity procurement from NB Power.*

Figure 2 below shows the accumulating net present cost over the 50-year period for the ACS CT and alternative 100 MW BESS capacity options, using the three approaches described above to estimate the costs of the BESS resource during the extended year 21–50 period. It also shows the 20-year cumulative NPC for MECL's presentation of the BESS option, assuming a 20-year useful lifetime.

**Figure 2. Cumulative Net Present Cost of Capacity Alternatives – 100 MW CT and 100 MW BESS**




*Source: Synapse, using computational structure provided in MECL's response to Synapse IR-2d (first set of IRs). See Confidential Appendix A to this report for detailed computations.*

Figure 2 shows the broad patterns of accumulating net present costs are similar, reflecting the ratemaking approach used by MECL and seen in Appendix E to its Application. The figure provides the following insights on the comparative economics of these resources:

- Figure 2 shows three different possible expenditure paths for augmentation. While all three lead to an increased NPC, relative to the 20-year lifetime BESS option, the final NPC remains less than that of the current 100 MW CT resource from ProEnergy.
- The time value of money has a significant effect on the contribution of BESS augmentation costs in years 21–-50 to the overall net present cost of expenditures.

Projections of continuing real cost improvements for BESS technologies are also a key driver of augmentation costs for scenarios which assume partial or full replacement based on NREL ATB BESS cost projections.

- Figure 2 excludes the effect of energy arbitrage benefits arising from the BESS alternative. The BESS resource allows for increased purchase of resources from NB Power at a lower cost during off-peak periods (vs. on-peak periods) than is otherwise needed to meet load, since the BESS resource allows for time-shifting of this energy purchase. While these purchases are contractually from NB Energy Marketing, the source of this energy could be from either NB Power imports or from on-Island wind resource energy held by NB Energy Marketing (i.e., the West Cape wind farm).[81]
- Figure 2 also excludes the benefits of avoiding capacity purchases from NB Power, which would occur with all options.

### Timing of CT / BESS Alternatives

There are no timing concerns with procurement of a BESS alternative instead of the ACS CT option. A BESS option could be in place at the same time as the considered ACS option.

In response to a Synapse information request,[82] MECL noted that lead times for BESS resource equipment is roughly one year from an order for that equipment, and long-lead-time items associated with substation work could be up to 2.5 years. MECL notes in that same IR response that it could exercise mitigating measures to reduce the lead times of those longer project elements. This illustrates that a BESS capacity alternative could be available for operation on a similar timeframe as MECL is projecting for its 100 MW CT alternative, i.e. towards the end of 2028. If lead times for the longest element of an alternative project were 2.5 years, MECL would require approval to go ahead with a planned alternative by no later than mid-2026 in order for the alternative project to be online in roughly the December 2028 timeframe. If MECL is able to exercise mitigating measures to reduce the lead time for the long-lead-time substation equipment for earlier delivery, a longer period would be available for review and approval of any alternative.

### Energy Arbitrage and the Energy Value Premium for a BESS Capacity Alternative

Energy arbitrage value potential exists for battery storage resources by allowing an operator to charge the battery (i.e., buy) at times of low prices in the market, and sell the energy stored in the battery during times of high market prices. A PEI-wind-focused generic variation on this conventional theme is

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[81] MECL response to Synapse IR-2c (second set). Response in part: "Under current arrangements, energy generated by PEI wind resources and sold outside the province (i.e., West Cape wind energy) is contractually delivered to NB Power. Maritime Electric, in turn, receives its full allocation of firm or non-firm energy from NB Power. In practice, however, physical delivery does not always match these contractual flows. *Although the contract specifies delivery from NB Power, West Cape wind energy typically remains on PEI and is consumed locally. This reduces the amount of energy that must be physically imported from New Brunswick ("NB") through the submarine cable interconnection*." [*emphasis* added by Synapse]

[82] Synapse second set of IRs, IR-1.

to charge the battery during times of higher wind output and meet load during times of low wind output with the energy stored in the battery. Of course, electricity supplies for PEI load consist of much more than just PEI wind, and thus the full market context must be considered.

In the PEI-New Brunswick market context, one important element is that players (aggregate buyers such as MECL, and aggregate sellers such as New Brunswick) have an ability to transact at granular intervals (i.e., hourly) to consider – or exploit - the price differential that exists across the hours on any given day of the market. In this case, the markets driving the hourly price differences are the ISO NE day ahead and real time energy market, at the border between New Brunswick and New England. ISO NE has a defined pricing point for this border (NB External Node #4010, Salbrynb345_1).

New Brunswick Power is directly connected to and is an active player in this market and should (as an economic matter) directly consider the hourly price differentials that exist. As long as MECL has the ability to contract with New Brunswick Power for at least a portion of potential energy purchases on an hourly level,[83] MECL is exposed to the opportunity to "buy low" rather than buying at the average price (over any given period, such as a year or a month), or buying at a high price during the peakiest periods.

In short, arbitrage works for MECL when they can minimize purchases from New Brunswick during high price periods by purchasing and storing energy (in the battery) during low price periods.

MECL underestimates the energy arbitrage value premium of a BESS capacity alternative in its Application. MECL states that the energy arbitrage use case does not provide value for a BESS resource because the difference between average annual peak and off-peak prices at the NB node of ISO NE is only CA $11/MWh.[84]

In reality, the energy arbitrage opportunity for MECL varies across the year depending on the season and the price formation fundamentals. These fundamentals are revealed in the daily patterns of price differences—especially those between peak and off-peak periods *for the purpose of buying charging energy*. It is greatest during seasonal peak periods (winter, summer) when loads are higher and spot price differences can be greater between on- and off-peak hours of any given day. For all periods, MECL can and should be selective in using the BESS for arbitrage opportunities only when such arbitrage exists, and only in consideration of other reliability-based needs (such as maintaining a certain level of charge in the BESS for contingency mitigation). In general, energy arbitrage *analysis* should be a daily operational occurrence and arbitrage itself (through operational decisions to charge and discharge) should be selected if the price differences are large enough. MECL's example in the preface to the IR

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[83] MECL confirmed this during the September technical conference when discussing their interactions with New Brunswick Energy Marketing for the Energy Purchase Agreement renewal or renegotiation required before the end of 2026. While the current EPA contains "fixed" pricing (MECL 11/12/25 preface to Synapse second set of IRs, page 2), going forward this is not required to be the case.

[84] This is based on ISO NE designated on-peak and off-peak periods during 2024. Source: MECL, preface to the response to Synapse second set of interrogatories.

response does not represent optimal selection of the greatest value arbitrage opportunities that will exist for the BESS resource.

When considering how MECL could operate a PEI BESS to maximize value, the following points are important to consider:

1. Optimal price arbitrage behavior will not be aligned solely with the ISO NE peak and off-peak periods, as opportunities for economic charging and discharging cover different hours.
2. BESS dispatch needs to consider the available wind supply patterns on PEI (which will often influence the New Brunswick energy prices).
3. BESS dispatch should aim to avoid operation of MECL's diesel peaking resources, which are high cost.

All these value elements must be considered when analyzing the energy premium opportunity, whereas MECL only reviewed the difference between ISO NE average peak / off-peak energy prices under ISO NE's hourly definitions.

A more careful analysis of the patterns of NB Power opportunity costs for energy is required to gauge the actual value of the energy arbitrage premium associated with a 4-hour or 6-hour BESS resource on PEI. We recommend MECL conduct such an analysis. The analysis should include consideration of how its projected increasing use of the on-Island CTs over time would affect the ongoing opportunity to reduce such use for generating energy, which can be much more expensive than energy from wind or from NB Power used to charge the BESS.[85]

Synapse conducted a high-level analysis of potential BESS arbitrage opportunities at a finer granularity than MECL and found there is a much higher arbitrage potential than MECL estimated. Table 3 below illustrates a high-level analysis of the daily spread of hourly New Brunswick node prices between November 2024 and November 2025. It shows the average daily difference between peak prices and off-peak prices.[86] There are 54 winter days and 138 total days with average price differences between 6-hour peak periods and 18-hour, off-peak periods greater than $USD 20/MWh. These days are highlighted in green in the table below. We estimate that such a pattern can lead to annual arbitrage value ranging from $1 million to $2 million ($CA) for a 100 MW, 6-hour duration BESS resource. This estimate is based on certain assumptions including an average annual BESS capacity factor and the

[85] MECL response to Synapse IR-4 and IR-5 (second set) show increasing energy needs from the CT resource, more than doubling between 2029 and 2033, with total diesel fuel consumption costs increasing to above $5 million per year by 2030, and more so by 2033.

[86] Here, peak hours are defined as hours ending 18-23, and off-peak hours are defined as hours ending 1-17, 24.

average cost difference between charging energy and the value of avoided energy purchases during BESS discharge periods.[87]

**Table 3. Average Daily NB Node Price Difference for BESS Charging – Peak (HE18-23) minus Off-Peak (HE24, HE1-17), NB External Node (ISO NE) Price Data ($US) from November 2024 through October 2025**

| Day of Month / Month of Year | January | February | March | April | May | June | July | August | September | October | November | December |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 5 | 36 | -9 | -18 | 29 | 21 | 53 | 17 | 13 | 10 | 16 | 54 |
| 2 | 35 | 70 | 85 | 63 | 19 | 17 | 13 | 16 | 15 | 27 | 11 | 21 |
| 3 | 37 | -53 | 49 | 4 | 39 | 12 | -2 | 42 | 22 | 11 | 17 | -9 |
| 4 | 62 | 76 | -1 | 19 | 10 | 12 | 9 | 36 | 19 | 33 | 0 | 31 |
| 5 | 81 | 49 | -5 | 10 | 40 | 38 | 33 | 23 | 7 | 53 | 11 | -1 |
| 6 | 13 | -13 | 27 | 23 | -30 | -18 | 24 | 10 | -19 | 53 | 17 | 34 |
| 7 | -8 | -1 | 17 | 10 | 30 | -6 | -6 | 36 | 7 | 1 | -5 | 28 |
| 8 | 27 | 22 | 21 | -3 | 30 | 19 | 29 | 24 | 11 | 0 | 4 | -4 |
| 9 | 22 | 20 | 11 | -25 | 6 | 0 | 18 | 29 | 9 | 38 | 23 | -17 |
| 10 | 55 | -23 | 22 | 49 | -3 | 4 | 8 | 92 | 23 | 11 | 7 | 7 |
| 11 | -9 | -10 | 11 | 4 | 34 | 36 | 27 | 23 | 15 | 17 | 13 | -2 |
| 12 | 6 | -36 | 21 | 4 | 27 | 20 | 22 | 31 | 23 | 9 | 20 | 6 |
| 13 | 28 | 56 | 22 | -5 | 38 | 6 | 37 | -4 | 15 | 3 | 44 | 29 |
| 14 | 109 | 21 | 10 | 15 | 35 | 5 | 25 | 27 | 27 | 9 | 33 | -9 |
| 15 | 13 | 73 | 19 | 13 | 43 | 16 | 65 | 21 | 12 | 14 | -4 | 12 |
| 16 | 88 | -13 | 10 | 39 | 8 | 23 | 33 | 19 | 14 | 6 | 1 | 9 |
| 17 | -38 | 26 | 1 | 41 | 8 | 18 | 1 | 8 | 16 | 15 | 13 | 16 |
| 18 | -14 | 27 | 17 | 37 | 14 | 9 | 9 | 10 | 29 | 9 | 7 | 13 |
| 19 | 42 | 15 | -7 | -16 | 3 | 7 | 31 | 22 | 41 | 12 | 26 | 25 |
| 20 | 47 | 12 | 10 | 42 | 43 | -5 | 18 | -7 | 20 | 1 | -20 | 41 |
| 21 | -7 | 22 | 12 | 15 | 11 | 22 | 19 | 3 | 20 | 23 | -1 | 10 |
| 22 | -15 | 49 | 15 | 21 | 2 | 33 | 26 | 13 | 17 | 10 | 5 | 41 |
| 23 | 1 | 34 | 39 | 40 | 5 | 140 | 14 | 9 | 24 | 24 | 7 | 1 |
| 24 | -12 | -16 | 8 | 33 | 17 | 537 | -52 | 28 | 4 | 15 | 15 | -85 |
| 25 | 42 | 29 | -2 | 21 | -1 | 113 | -19 | 8 | 6 | 21 | 2 | 3 |
| 26 | 33 | 20 | 9 | 6 | 25 | -27 | 6 | 8 | 14 | 22 | -5 | 46 |
| 27 | 38 | 11 | 5 | 1 | 16 | 10 | 29 | 5 | 19 | 5 | 10 | -3 |
| 28 | 82 | 15 | 6 | 74 | 12 | 36 | 98 | 4 | 24 | 12 | -14 | -5 |
| 29 | -47 | 0 | 10 | -39 | 6 | 30 | 128 | 9 | 25 | 16 | 20 | 2 |
| 30 | 16 | 0 | -4 | 79 | 2 | 17 | 7 | 11 | 9 | -2 | 13 | 12 |
| 31 | -1 | 0 | -2 | 0 | -1 | 0 | -27 | 17 | 0 | 3 | 0 | 6 |
| **Days/Mo. Delta>$20/MWh** | **16** | **14** | **8** | **13** | **12** | **11** | **15** | **13** | **11** | **9** | **6** | **10** |

*Note: The values shown for each day are the difference between the daily average 6-hour period (HE17-HE23) real-time NB node price and the daily average real time price for the 18-hour period outside of the HE17-HE23 window, or HE24 and HE1-HE17. This split is used to roughly estimate the time periods over which charging and discharging would occur for the purpose of the illustrated arbitrage potential. Source: ISO NE Real Time Hourly Price Data, NB External Node #4010, Salbrynb345_1, 1/1/2024 – 10/31/2025. Computation of daily average peak and off-peak values and table summaries and formatting by Synapse.*

## NB Interface Reliability Considerations

PEI will remain dependent on the NB-PEI interconnecting tie lines and related capacity and energy resources from New Brunswick well after the purchase of on-Island capacity resources. MECL's

[87] The value of roughly $1 million per year is equal to CA$30/MWh (weighted average price period difference) multiplied by 54,750 MWh (which represents an annual average 100 MW 6-hour BESS capacity factor of 6.25%), or $1,642,500 less the cost of BESS system losses required to be procured to charge the BESS (=.125*54,750*90 = $615,937.5). An average charging energy cost of $90 is used. This represents a winter operation. The $2 million/year value assumes all-year operation for arbitrage, at a BESS capacity factor of 12.5%. Both of these assumptions reflect using the 6-hour BESS roughly one-half of the time it would be available to undertake a daily charge/discharge cycle of 6 hours discharging/18 hours charging. The computation considers the pattern of pricing seen at the NB external node in Table 3.

projection for firm capacity purchase from NB Power remains at 190 MW in 2033, even if the full amount of on-Island capacity requested in the Application (150 MW) is eventually secured.[88] MECL is not planning for on-Island resources to fully replace firm purchases from New Brunswick. The full disconnection of the interconnection between the provinces is not a planning constraint, and MECL acknowledges, clearly, that loss of load could occur under instances of full disconnection.[89]

There will always be some (relatively minor) risk of loss of load accompanying any MECL resource plan that includes purchases across the interconnection, as the risk of losing the entire interconnection, however small, is above zero.[90] The more likely scenarios are partial disconnection and loss of some of the current 300 MW of firm import capability. Both CT and BESS resources provide mitigation against partial disconnection loss of import capacity. Depending on operational status, either the CT or BESS resource could, in theory, outperform the other.

In comparing capacity resources in the Application, MECL stated "that a battery's state of charge during a contingency event is not known,"[91] as part of its rationale for not considering a larger BESS resource (beyond 10 MW). MECL also acknowledged that "system operators can forecast charge-to-discharge transitions most of the time."[92] It is true that system operators will need to consider which resources—including the BESS, among other options—would need to be available to address a contingency situation. However, the overall economics for considering a BESS compared to a CT resource should not rest solely on a comparison of a *single* attribute for *one* aspect of operational requirements of each resource. In other words, the evaluation of BESS versus CT economics should go beyond a comparison of their potential availability during a contingency, which translates to the state of charge for BESS, or availability of fuel for CT.

In addition, it is worth noting that during the full disconnection event of 2018, there were periods when the CT resource was not operating in a fully reliable mode; it tripped off several times.[93] This point

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[88] Application, Table 15, Capacity Resource Adequacy Assessment.

[89] Capacity Resource Study, page 17: "Accounting for the anticipated continued load growth on PEI, and also considering the continued growth of DSM on the island, approximately 85 MW of additional dispatchable capacity is required to bring the current ratio of dispatchable capacity to peak load back in line with the 50% historical threshold. Note that even with this amount of additional dispatchable capacity, there would likely still be a need for rolling blackouts to be implemented if PEI were disconnected from the mainland." July 2023 report, page 22: "Note that even with up to 150 MW of additional dispatchable capacity, there may still be a need for load shed to be implemented if PEI were not able to secure enough electricity imports to fully meet load; however, the additional 125 to 150 MW would help to bring the risk of load shed to be consistent with historical levels".

[90] For that matter, all resource plans include some loss of load risk, under the conventional 1-day-in-ten-years loss-of-load event standard for resource adequacy considerations.

[91] Application, page 100.

[92] MECL preface to response to Steven Chandler IRs, page 2. May 2025.

[93] MECL response to Synapse IR-8 (first set), Appendix B report of the 2018 storm and restoration event, with its Appendix A: Summarized sequential event log: 0804h: CT3 breaker closed, connecting CT3 to the system. Within seconds, the unit tripped off due to an issue with the associated switchgear. 0854h: CT3 was started a second time. However, during its start-up sequence the supply was lost from New Brunswick, causing a system wide blackout and causing CT3 to trip off. 1134h:

merits consideration when assessing the relative operational reliability (separate from fuel or charge state) of the alternative capacity options.

A BESS resource in grid-forming mode is a modular, highly flexible, ancillary-service-providing capacity resource with instantaneous operation. Not only could a BESS provide a reduction in risk of energy curtailment from NB Power due to its ability to shift energy across time periods, it could also provide immediate dispatchable capacity and meet ongoing on-Island capacity needs.

### Sustainability Objectives

One of the three key considerations for on-Island capacity supply is meeting sustainability and carbon emission reduction goals. MECL states that "Although this project will result in an increase of generation emissions, the Company's goal of integrating additional wind and solar energy resources to the grid will significantly reduce the Company's Scope 2 and 3 GHG emissions."[94] MECL does not assess the longer-term implications of its proposed CT resource plan in any other analytical manner, including the plan for the CT to operate more frequently over time.

S&L states in the Capacity Resource Study that both CT and RICE resources will have a small impact on MECL's overall carbon emissions because the plan is to use them infrequently and as backup capacity. However, neither MECL nor S&L perform any analysis to carefully consider which resource, over time, would better match PEI's goals for emission reduction. S&L qualitatively states that a "… BESS would be able to better help Maritime Electric meet sustainability goals" as more wind is installed on PEI beyond the 70 MW planned for the coming years, but it only recommends that a comparative assessment be performed to which is the better solution.[95] MECL notes that its planned project will steadily increase fossil fuel consumption, and the capacity factor of the proposed CT resource will increase over time.[96]

BESS is a highly effective capacity supply resource for integrating greater amounts of PEI wind while simultaneously meeting MECL's immediate capacity supply aims. A BESS resource would reduce and may even eliminate MECL's "hold to schedule" CT needs (current and projected).[97] If PEI's goal is to continue to become less reliant on New Brunswick energy imports and increase on-island renewable

…In addition, the CT3 output voltage was low and could not be increased, limiting the amount of output from the machine to existing levels. 1615h: CT3 tripped offline (low voltage trip), cutting off supply to all customers in Charlottetown. …a delay restricted CT3 from starting its cool-down cycle, forcing it into a 4-hour cool down lockout. This restricted CT3 from restarting until after 2040h.

94 Application, page 126.

95 Capacity Resource Study, page 70.

96 MECL response to Synapse IR-4 and IR-5 (second set) show increasing energy needs from the CT resource, more than doubling between 2029 and 2033, with total diesel fuel consumption costs increasing to above $5 million per year by 2030, and more so by 2033.

97 MECL response to Synapse IR-5 (second set), Table IR-5(a)I shows "hold to schedule" amounts required by the CT resources. MECL response to Synapse IR-9 (first set) listed a "maximum" historical hold-to-schedule capacity requirement of 64 MW (in 2021), with average amounts ranging from 19 MW to 34 MW between 2019 and 2023. This illustrates that a 100 MW BESS resource could effectively eliminate the need for any CT operation to meet hold-to schedule requirements.

energy, a BESS resource meets this aim, while continuing to provide the capacity attributes sought for on-Island supplies.

BESS resources allow for "surplus" wind to be absorbed on-Island and used at a later period of the day. In grid-forming mode, a BESS resource can instantaneously provide the stability and voltage support needed to keep on-Island wind resources on-line in the event of a disconnection event.

# 3. BESS Capacity Alternative and Winter Peak Operation

This chapter illustrates how a BESS alternative would function and support reduction of New Brunswick energy curtailment risk, and it provides a cost comparison for three specific scenarios: MECL's proposed ACS, an alternative scenario using 100 MW of 6-hour BESS resource instead, and a third scenario using a 4-hour BESS resource instead of a 6-hour BESS resource.

## 3.1. BESS as an Alternative to CTs

The alternative scenarios propose the replacement of the CTs with either a 6-hour or 4-hour 100 MW BESS. We briefly summarize the key attributes for considering BESS resources as a direct alternative to the proposed CT project.

***Economics***

A BESS resource provides essentially the same capacity benefit as the proposed CT while providing greater operational flexibility, improved energy benefits, and better support of PEI's sustainability targets for increasing the amount of procured renewable energy from on-Island sources. MECL has not sufficiently analyzed the alternative of a 100 MW utility-scale BESS as a direct, on-Island capacity resource for installation at the Charlottetown plant site. MECL has a opportunity to install 100 MW of new supply at a site with interconnection infrastructure already in place at the existing plant. If the BESS is a better economic alternative, then this opportunity should favor the BESS over the CT project.

A BESS resource provides additional benefits on a regular, blue-sky-day basis that are not available with the CT alternative, such as zero-local-emission grid balancing and energy arbitrage. This resource also aligns with PEI policy to become net-zero energy by 2030 and have net-zero GHG emissions by 2040. A BESS resource would set PEI on a trajectory towards more renewable energy in the long term and would help to reduce PEI's reliance on New Brunswick Power purchases of fossil-fuel-sourced electricity.[98] Integration of on-Island BESS would allow for further development of the island's wind energy resources

[98] Prince Edward Island, 2040 Net Zero Framework, Accelerating Our Transition to a Clean, Sustainable Economy , February 2022, accessed on Nov 13 2025, available at: https://www.princeedwardisland.ca/sites/default/files/publications/2040_net_zero_framework.pdf.

without risk of “surplus” wind generation as BESS allows for energy storage when wind is generating, and energy dispatch during low wind periods. We present this information as background context for considering the BESS alternative, not how it may relate to the Commission’s statutory review framework.

***Technical and Reliability Attributes***

A grid-forming BESS resource provides voltage and stability support and greater support for integration of renewable energy than the CT option because of its operational flexibility and instantaneous response to events. It inherently allows for economic arbitrage opportunities for energy needs. Its resource adequacy attributes allow it to replace procured capacity from NB Power, at relatively high ELCC values of likely 1.0 for 6-hour resources and 0.9 for 4-hour resources.[99] Nova Scotia Power’s recent completion of installation of three, 50 MW 4-hour BESS resources can serve as a useful and practical example of BESS installation for reliability and sustainable energy support in the Maritimes.[100] Unlike the CT project, there is no need for a synchronous condenser at the Charlottetown site with a BESS resource because it directly provides for dynamic reactive power support; it also provides fast frequency response and can directly address MECL’s “hold to schedule” needs without operating a CT.

***Timing***

A BESS alternative appears to be available on the same timeline as, or sooner, than the CT alternative, based on MECL’s response to IR-1 of the second set of Synapse interrogatories.[101] While MECL states in the Supplemental Filing that its proposed 100 MW CT represents the only viable and cost-effective solution to mitigate the province’s increasing capacity deficit “within the required timeframe,” the response to IR-1 indicates that the timeframe is not a constraint for the BESS resource alternative.

## NB Power Capacity Accreditation for BESS Resources

NB Power IRP describes how it considers the ELCC of BESS resources for capacity adequacy purposes.

> “The analysis shows that the first 250 MWs of batteries provide almost full capacity value[.] [As] the installed capacity increases, the reliability benefits decrease as we enter diminishing returns. To create a reliable system that meets the NPCC reliability metric of a loss of load expectation of less than 0.1 days per year, NB Power needs to have a

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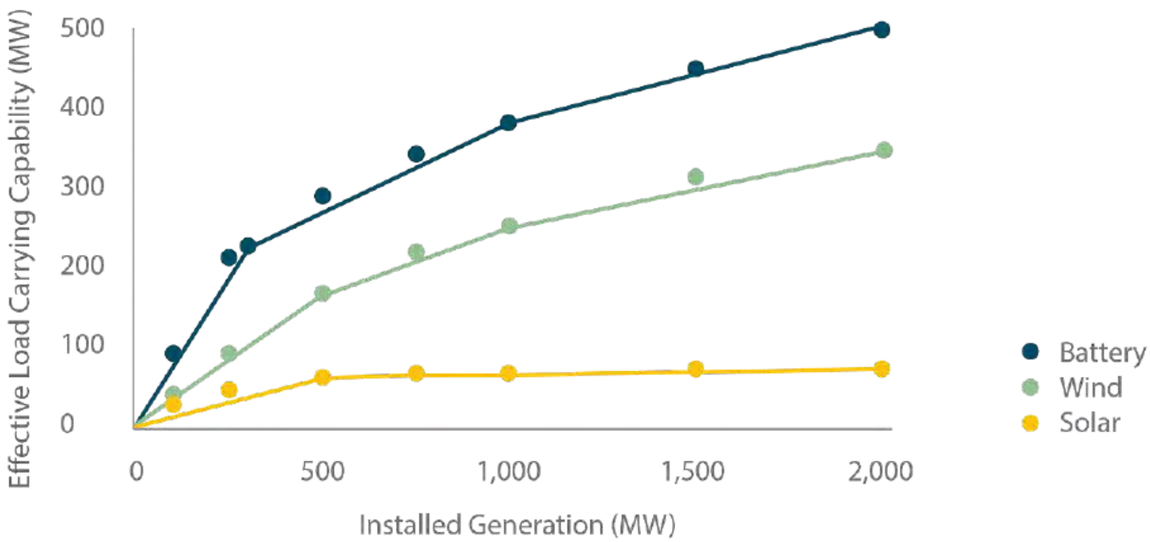
99 NB Power 2023 IRP, Figure 9.2, page 46.

100 See, e.g., Nova Scotia Energy Bureau Decision in Matter M11539, June 2024, for Nova Scotia Power’s 3x50 MW (4-hour duration) battery energy storage system installations at three sites in Nova Scotia. Available at https://nserbt.ca/sites/default/files/NSUARB%20Board%20Decision%20-%20Nova%20Scotia%20Power%20Incorporated%20%28M11539%29.pdf.

101 MECL response to Synapse second set of interrogatories, IR-1. The response indicates a one-year delivery lead time for the core BESS components such as battery modules and inverter systems. MECL notes that some ancillary equipment, such as step-up transformers and circuit breakers may have 2 to 2.5 year lead times, but that “there are some mitigating measures that Maritime Electric could exercise to reduce lead times for some of the long-lead items.”

variety of generation sources and reliable backup generators. NB Power recognizes that combinations of wind and battery and to a greater extent solar and battery can increase the effective load carrying capacity of the combination above the individual components. However, this difference has no impact on the model at the current levels of battery penetration." (NB Power 2023 IRP at p.45)

**Figure 3. NB Power 2023 IRP - Estimate of BESS ELCC from E3 Analysis**




*Source: NB Power 2023 IRP, Figure 9.2, page 46.*

As seen in Figure 3 above from NB Power's IRP, and as noted in the text, the ELCC of the initial BESS resources for the NB Power system is fairly high with diminishing returns as the penetration of these resources increases. However, as the report states, the first tranche of batteries will provide "almost full capacity value." For the purposes of comparative economics, Synapse assumes the 100 MW 4-hour BESS resource would be accredited with 90 percent of its nameplate capacity to meet NB Power resource adequacy obligations. A 6-hour BESS resource would likely be accredited at 100 percent of its nameplate capacity.

## 3.2. On-Island Wind as Complementary Resource for Capacity and Energy

Some of PEI's existing wind resources suffered reduced operation during the extreme winter event in 2023. However, PEI's winter wind resource is economic, reliable, and—notwithstanding the extreme weather event of 2023—can perform well during periods of low temperature and higher energy needs. In combination with energy storage resources that allow for a "smoothing" of overall availability of wind generation during winter peak days, the resource greatly helps to reduce the risk of curtailment of energy imported from New Brunswick during winter peak days and extreme event days. As noted in S&L's Capacity Resource Study:

> Consistent and strong wind speeds are one of PEI's best resources from a power generation perspective. New wind farms on PEI could approach a 50% capacity factor on an annual basis, which is among the highest in the energy industry for onshore wind farms. Maritime Electric already has under contract a total of 92.5 MW of wind capacity that it utilizes to serve load, and an additional 70 MW of wind generation is planned. Wind is a clean energy source and its continued development on PEI will be a key part in helping Maritime Electric to achieve its carbon emission reduction goals.[102]

Since the extreme weather event of 2023, MECL has indicated that PEI's existing wind resources have seen performance improvements due to mitigation measures taken by the owners to allow for more reliable operation during cold winter periods.[103]

As MECL noted in its response to Synapse's IR-15(d) (first set), it continues to use the current ELCC rating for PEI wind for resource adequacy, or capacity requirements; actual output during extreme events can, and likely will vary. During the February 2023 event at the time of the peak, MECL states that wind production was 26 MW, above the ELCC value of 23 MW. This was for MECL's contracted wind, not the entirety of the PEI wind resource. Figure ES-4 of the Extreme Weather Event Capacity Impact report shows a value of roughly 40-45 MW (all PEI) at time of system peak. Notably, as MECL stated in the IR-15 (d) response, during that event wind turbine performance was poor, even though it was greater than the ELCC rating for MECL's contracted wind. Most importantly, Figure ES-4 shows that the wind output just prior to the turbine shutdowns or their output reduction was much higher (160 MW of producing wind on PEI at 4 PM on February 3, 2023) and the wind speeds continued to be high throughout February 4, 2023. Lastly – perhaps most importantly for the purpose of considering what the output level of PEI wind will be during extreme events – MECL confirmed in the IR-15(d) response that "most PEI wind farms are now believed to be well positioned to maintain operation during extreme cold weather events such as the February 3 to 5, 2023 polar vortex".

## 3.3. Battery Energy Storage System Operation – Winter Peak Period

In this section we illustrate an alternative approach to MECL's proposed Accelerated Capacity Solution using a new 100 MW, 6-hour duration battery energy storage system as the on-Island capacity resource, instead of 100 MW of new CTs. We show how such a resource would operate during an MECL winter peak period, using the 3-day winter peak period of January 29–31, 2025, as an example.

A BESS resource's functionality would include grid-forming capabilities to support voltage and ancillary service requirements under a disconnection scenario.[104] Under normal circumstances, including during

[102] Capacity Resource Study, page 40-41.

[103] MECL response to Synapse IR-14 and IR-15 (first set).

[104] In response to Synapse IR-13 (first set), MECL indicates that "…the addition of battery…resources is not expected to mitigate these concerns [power system support services]." S&L also states, in the Capacity Resource Study at page 11, "In the event that the Charlottetown CT3 was also lost, the island would have an extreme shortfall in dispatchable generation

winter peak periods, MECL and/or NB Power would optimize its daily use on either an economic basis or to consider those periods when New Brunswick energy imports would be at greatest risk of curtailment due to availability.[105] In our example, we use a 6-hour BESS resource. However, we also recommend that MECL considers the 4-hour battery storage option for initial installation, with the potential to add more energy storage to a configuration with a fixed power output magnitude such as 100 MW.

The example below first shows the actual 3-day dispatch during the peak week in January 2025, and then the resulting stylized dispatch of a 6-hour 100 MW BESS resource if available. The example is *illustrative*; there are a number of ways in which MECL and NB Power might optimize a daily dispatch to minimize the risk of needing to curtail energy supplies to PEI. MECL and NB Power likely already examine near-term weather forecasts to anticipate changes in on-island load and wind output, and they likely review expected energy prices in New Brunswick and the cost to operate on-Island resources. This type of analysis would inform the decisions to charge or dispatch the BESS. In the future, if or when MECL has procured more on-Island wind resources, the optimization would change.

As the example shows, the BESS resource serves as a critical energy availability buffer, allowing MECL and NB Power to optimize system dispatch in consideration of each day's PEI wind output forecast (both MECL and PEIEC[106] wind assets)[107] and considering all other system constraints and parameters (e.g., hourly load and available supply both on-Island and across New Brunswick). As we noted in Chapter 2, the BESS resource is not intended to solely reduce the net peak load seen on MECL's system, although that is often an outcome because it usually discharges during peak hours.

An important purpose of the BESS is to provide flexibility to occasionally discharge during hours when other resources exhibit low availability or are highly priced, even if it is not during the peak hour or hours of the day. These situations may include wind output reductions, unavailability of CTs, or tight or high-priced energy conditions on the New Brunswick grid. During a particularly windy period, the BESS may not fully or even partially discharge even if it is a peak-load hour because the on-Island wind resource (MECL's, or PEIEC's via NB Energy Marketing "imports") is available at a high capacity factor. During these periods, as during other periods, the BESS resource is available for instantaneous operation in the event of a contingency.

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that could be used for energy balancing; thus an estimated 0% of the on-island wind generation could be utilized without risking system collapse." A BESS resource configured in grid-forming mode resolves these concerns and can be utilized during islanded operation to support use of on-Island wind as a contributor to meeting needs during an extreme disconnection event.

[105] Response to Chandler IR – MECL and NB have predictability capability.

[106] Prince Edward Island Energy Corporation (PEIEC) sells the output of the West Cape wind farm to NB Power Energy marketing.

[107] As noted in response to Synapse IR-2 c (second set, November 12, 2025), NB Power can deliver energy to MECL from their wind energy entitlements at West Cape, which "…reduces the amount of energy that must be physically imported from New Brunswick ("NB") through the submarine cable interconnection."

Essentially, the BESS resource helps to render what is usually considered a one or even multi-hour peak period capacity concern (i.e., a tight reliability constraint) into a more manageable energy delivery problem spanning much of the entire day (i.e., a looser reliability constraint). The flexibility of the BESS resource (essentially instantaneous charging or discharging capability) is a critical functionality of the asset and is often undervalued as an attribute of the capacity investment.

### Three-Day Hourly Pattern – Winter Peak, January 29-31, 2025

Figure 4 below shows the supply and load patterns during January 29–31, 2025, the peak period last winter.

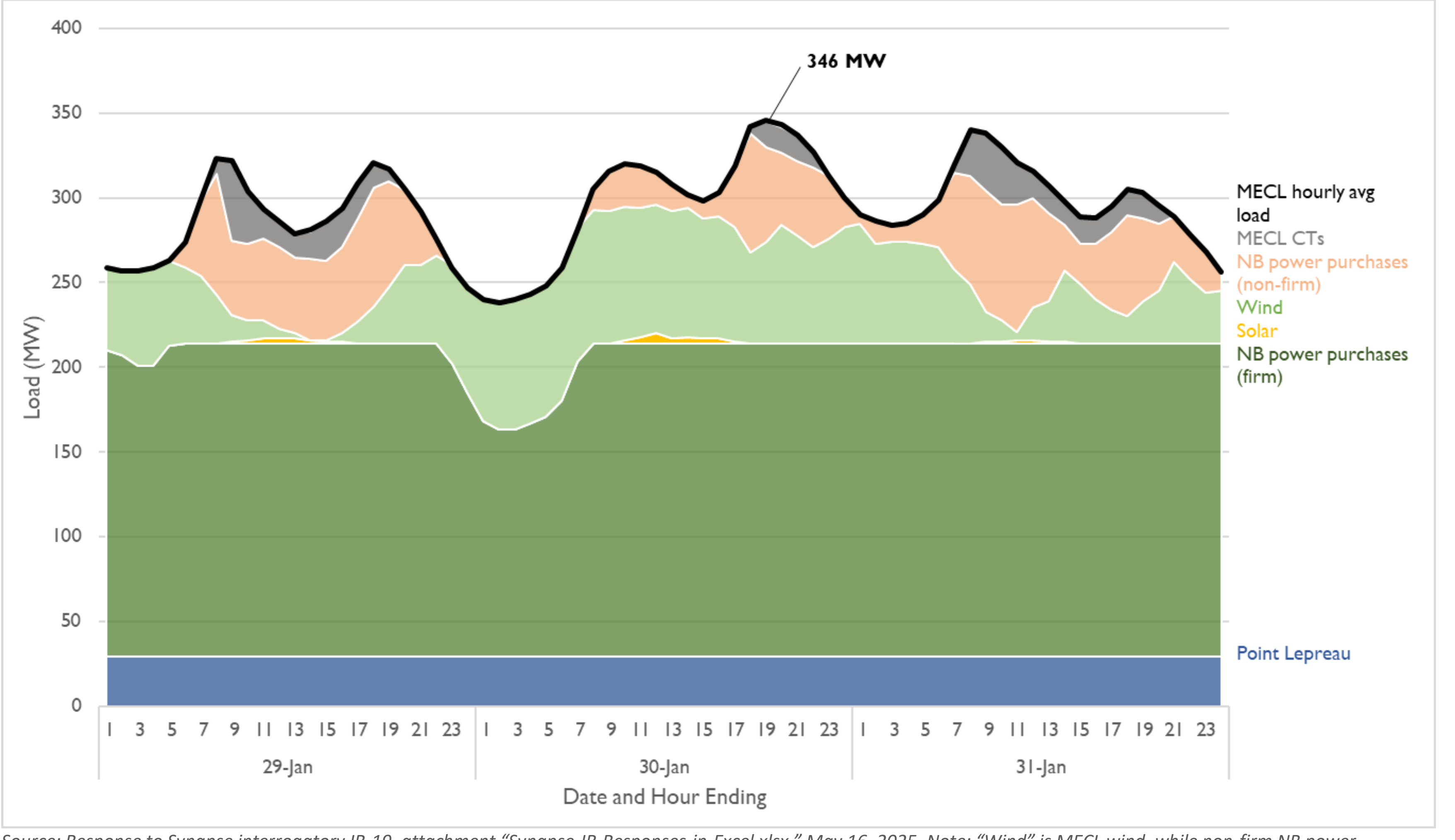
As seen in Figure 4, load dipped to below 250 MW early in the morning (1 AM) on January 30 and rose throughout the morning to peak at roughly 320 MW at 8 AM. During the early morning dip in load (1 AM – 5 AM), and as seen on the graph, MECL reduced its firm energy purchases and did not import any non-firm energy. After seeing an afternoon dip, MECL load again increased throughout the evening to reach an evening peak of 346 MW in the hour ending at 7 PM. Noticeably, wind output was relatively high during this peak period, and imports from New Brunswick were at 199 MW (1 hour earlier, they were at 216 MW). During the next day, wind levels were lower, and non-firm imports increased, such that the average physical flow (including non-firm energy) reached 303 MW between 8 AM and 11 AM on January 31.[108]

During the three-day period between January 29–January 31, firm power purchases from New Brunswick provided 61 percent of total MECL energy. Non-firm power purchases from New Brunswick, generation from Point Lepreau, and MECL's combustion turbines contributed 10 percent, 10 percent, and 3 percent, respectively. Meanwhile, MECL wind provided 16 percent of the total energy consumed during this period. During the hour of absolute peak of 346 MW, MECL wind generated 60 MW or 17 percent of total load. It is our understanding that for any of the hours with imports from New Brunswick energy, including the peak hour, NB Energy's wind resources on PEI (West Cape, 99 MW) could have been a contributing resource to make up some of the amount shown in the "non-firm imports" category.[109]

[108] MECL included physical NB-PEI flows in its response to IR-19. "NB-PEI Physical NB-PEI Intertie Hourly Average MW (+ = importing) (- = exporting)."

[109] Based on MECL's response to Synapse IR-2 c) (second set, November 2025).

**Figure 4. MECL resource loads and dispatched supply during January 2025 winter peak load event**




*Source: Response to Synapse interrogatory IR-19, attachment "Synapse-IR-Responses-in-Excel.xlsx," May 16, 2025. Note: "Wind" is MECL wind, while non-firm NB power purchases may include purchases from on-Island wind to which NB Power has entitlements.*

## Illustrative Dispatch – 100 MW BESS During 3-Day Peak Period - Leveling Net Load

A 100 MW, 6-hour duration BESS resource provides energy during critical hours of the peak day or during extreme weather event multi-hour periods. The BESS reduces off-island supply needs, and thus off-island energy supply curtailment risk, during critical hours. As we show in this illustration, using the battery option directly mitigates energy curtailment, as its 6-hour energy duration provides considerable increased flexibility to manage the peaks and utilize on-Island wind energy (MECL-owned, or PEIEC energy available from NB energy marketing) and import energy as available.

Figure 5 shows a hypothetical three-day charge and discharge cycle for a 100 MW 6-hour BESS resource that is included on MECL's system and is (conservatively) empty starting at midnight on January 29, 2025. Generally, BESS resources charge during overnight and early morning off-peak times and dispatch to reduce the evening net peak and small secondary morning net peak. The illustration essentially "flattens" the net peak load seen by the system, after accounting for battery output.

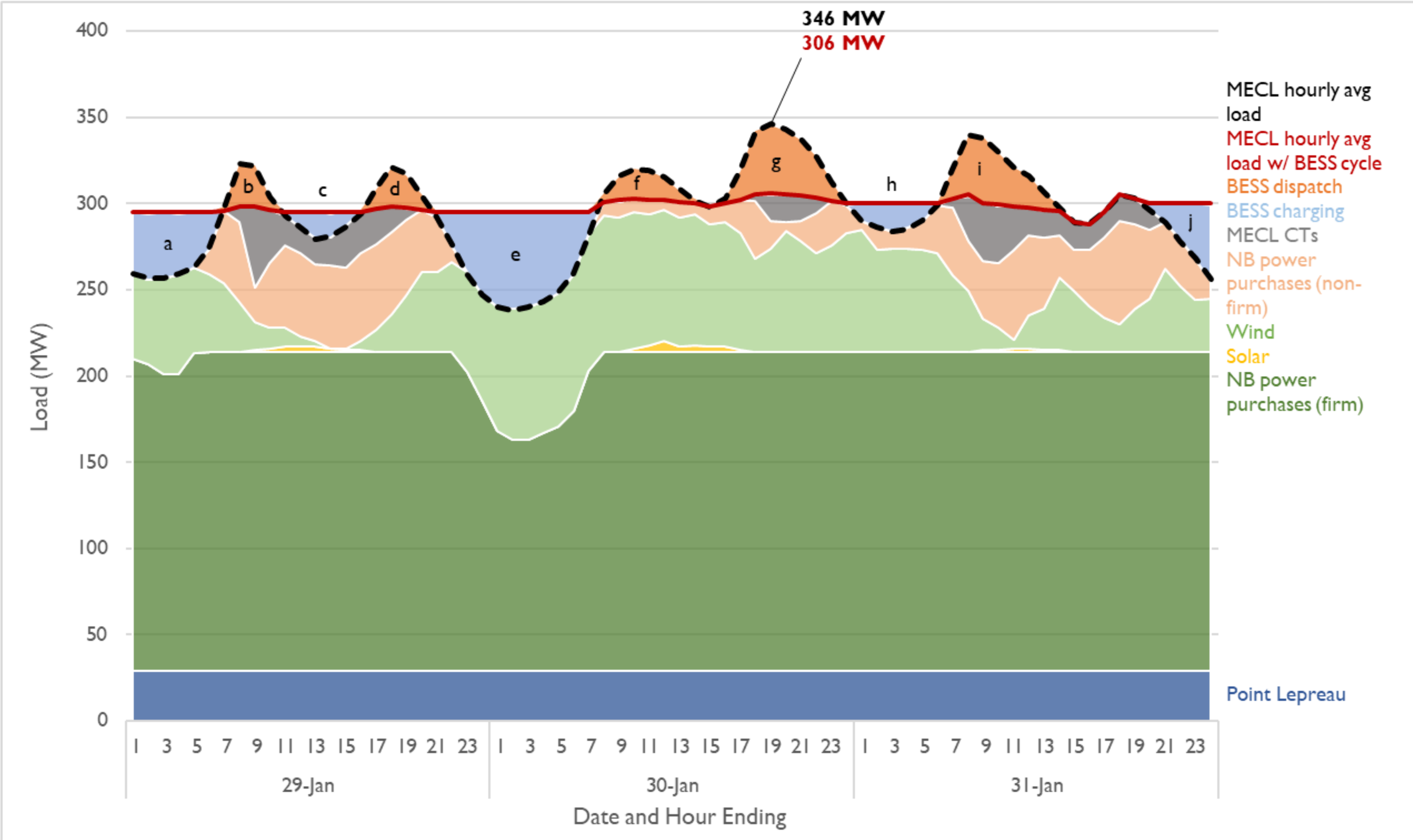
The goal of this illustrative example is not to suggest that MECL should operate a BESS with multiple charge and discharge cycles during a single day, but to demonstrate that a BESS could help load-shift and reduce winter net peaks during the tightest days. In this example, the BESS is a 6-hour duration battery (600 MWh) with an assumed efficiency of 87.5 percent, and it has variable charge or dispatch periods, depending on the average MECL hourly load. The 100-MW BESS with 6-hour duration battery allows for longer dispatch periods, which are helpful to handle prolonged periods of higher load.

This demonstrates a BESS resource could have reduced the net peak load to be supplied by resources from 346 MW to 306 MW at the peak hour, even if the BESS were empty at the beginning of the 3-day period. More importantly, the use of the BESS allows MECL or NB Power to dispatch available resources to meet load or charge the battery such that the overall curtailment risk during the period is minimized.

Critically, in this example the 100 MW capacity of the battery was never fully utilized. At most, roughly 40 MW was discharged, reducing the peak hour net load from 346 to 306 MW. The average battery state-of-charge during the 24-hour interval (January 30) was roughly 65 percent. Thus, most of the BESS was still available to serve as a capacity resource in the event of a contingency. Alternately the BESS headroom could be used to reduce the energy from CT resources on this winter peak day. MECL CTs were run for four hours on the 30th, and then for 14 hours on the 31st during a period with a relative wind lull.[110] The BESS resource we illustrate in this example could have eliminated the need for the existing CT operation on the peak day, if that would be considered by MECL to be more important than retaining charge for contingency planning purposes. Also, the battery headroom indicates even a 4-hour duration BESS would support capacity needs, although not as robustly as a 6-hour duration resource.

[110] MECL response to IR-19 (first set).

**Figure 5. MECL resource loads during January 2025 winter peak load event, with modeled 100-MW BESS dispatch**




*Source: Synapse re-dispatch of resources on 1/29-25 through 1/31/25, based on MECL data in response to Synapse interrogatory IR-19 attachment "Synapse-IR-Responses-in-Excel.xlsx," May 16, 2025. Note: "Wind" is MECL wind, while non-firm NB power purchases may include purchases from on-Island wind to which NB Power has entitlements. See text for description of redispatch.*

Figure 5 shows BESS charge and dispatch cycles broken up into lettered regions (a, b, c, etc.), which we describe in further detail below. “Net load” or “net peak” is actual load less the output of the BESS resource in that hour.

(a) Charge. The BESS is assumed to begin this exercise fully empty, i.e. 0 MWh. During early morning hours when on-island load is low, the BESS charges.

(b) Dispatch. The first peak of the day occurs during the morning. BESS dispatch reduces the net peak (load minus BESS output) by 24 MW.

(c) Charge. The morning lull allows for several hours of low levels of BESS charging.

(d) Dispatch. During the evening peak, the BESS discharges and reduces the maximum hourly net load by 23 MW.

(e) Charge. MECL experiences a dip in load overnight on January 29 and into the morning hours of January 30, which allows for a long charging period.

(f) Dispatch. BESS dispatches during the small morning peak and reduces this net peak by 16 MW.

(g) Dispatch. With energy available from the long overnight charging period on January 29/30, the BESS goes through another round of dispatch to reduce the 346 MW net peak at hour end 7 PM on January 30. During this event, the BESS reduces the net peak hourly load by 40 MW.

(h) Charge. Taking advantage of a small dip in load overnight, the BESS charges for several hours at low duration.

(i) Dispatch. The morning peak on January 31 reaches 340 MW. BESS dispatch provides 35 MW of net load reduction during this peak hour.

(j) Charge. The BESS begins to charge overnight on January 31 when the average hourly MECL load dips below 295 MW.

The energy to charge the BESS could come from a variety of resources and would be determined by economics of the least-cost resource (including import energy) and contingency planning for a potential peak load day. For example, during period (e) in Figure 5 MECL reduces its firm, already-contracted energy imports from New Brunswick since overall island load dips overnight (the “NB power purchases non-firm” series in tan drops to zero). Hypothetically, MECL could continue importing energy during these off-peak hours to charge the BESS. Otherwise, MECL has other resource options at its disposal. MECL could charge a BESS with on-island wind, or existing combustion turbines, depending on availability, cost-effectiveness, and near-term operational planning considerations.

### Illustrative Dispatch – 100 MW BESS During 3-Day Peak Period – Reduce New Brunswick Curtailment Risk

An alternative dispatch arrangement could be used to reduce the risk of energy curtailment from New Brunswick by reducing the amount of energy imported over the interconnection through timely, or near-term-optimized use of the BESS resource. In the "load levelizing" example above, the peak day (January 30) exhibited relatively lower flows over the interconnection because of on-Island wind output. MECL imported total firm plus non-firm energy equal to 284 MW at the peak hour (HE 7PM) on January 30.[111] However, physical flows over the interconnection at that hour were only 216 MW. The difference appears to be based primarily on NB Energy meeting its contract requirements by "delivering" energy from its on-Island wind entitlements.[112] Another BESS dispatch arrangement could reduce purchases from NB Power during the tightest time periods where there may be energy curtailment risk. This may not coincide with the peak hour or even the peak day during a multi-day winter peak period.

Optimizing BESS dispatch would require good data, analysis, and the ability to take rapid action to charge or discharge. With projections of load and wind and scheduled flows, MECL can devise protocols that allow for the use of the BESS to minimize the likelihood of curtailment by taking advantage of the predicted availability of on-Island and off-Island energy in near-term operational timeframes.

Figure 6 below illustrates a variation on the example above by modifying the BESS dispatch and superimposing two NB-PEI interconnection flow variables on the rest of the supply sources shown. The additional variables are (1) actual NB-PEI interconnection flows for the 3-day period, and (2) adjusted interconnection flows illustrating the effect of a modified BESS dispatch (reflecting charging during low interconnection flow periods and discharging during the periods exhibiting the highest interconnection flows). The modifications to the actual flow were premised on reducing the amount of energy flow that actually occurred during the two periods (one on January 29, and one on January 31) with highest physical flows from New Brunswick to PEI.[113] A simple manual exercise was used to illustrate the effect, maintaining the battery energy charge state above a minimum amount.

Figure 6 below thus shows an example of the direct effect of the BESS resource on reducing the risk of curtailment of New Brunswick energy that might otherwise occur during the highest energy import periods. For the hours 7AM to 7PM on January 29th, the average flow across the interconnection is reduced by 26 MW. For the hours 7AM to 5PM on January 31, the average flow was reduced by 37 MW. These flow patterns are seen on the lower half of the graph (secondary y-axis values). During the periods with lowest actual interconnection flows, the battery was charged, as seen with the "BESS charging" variable (blue) on the graph.

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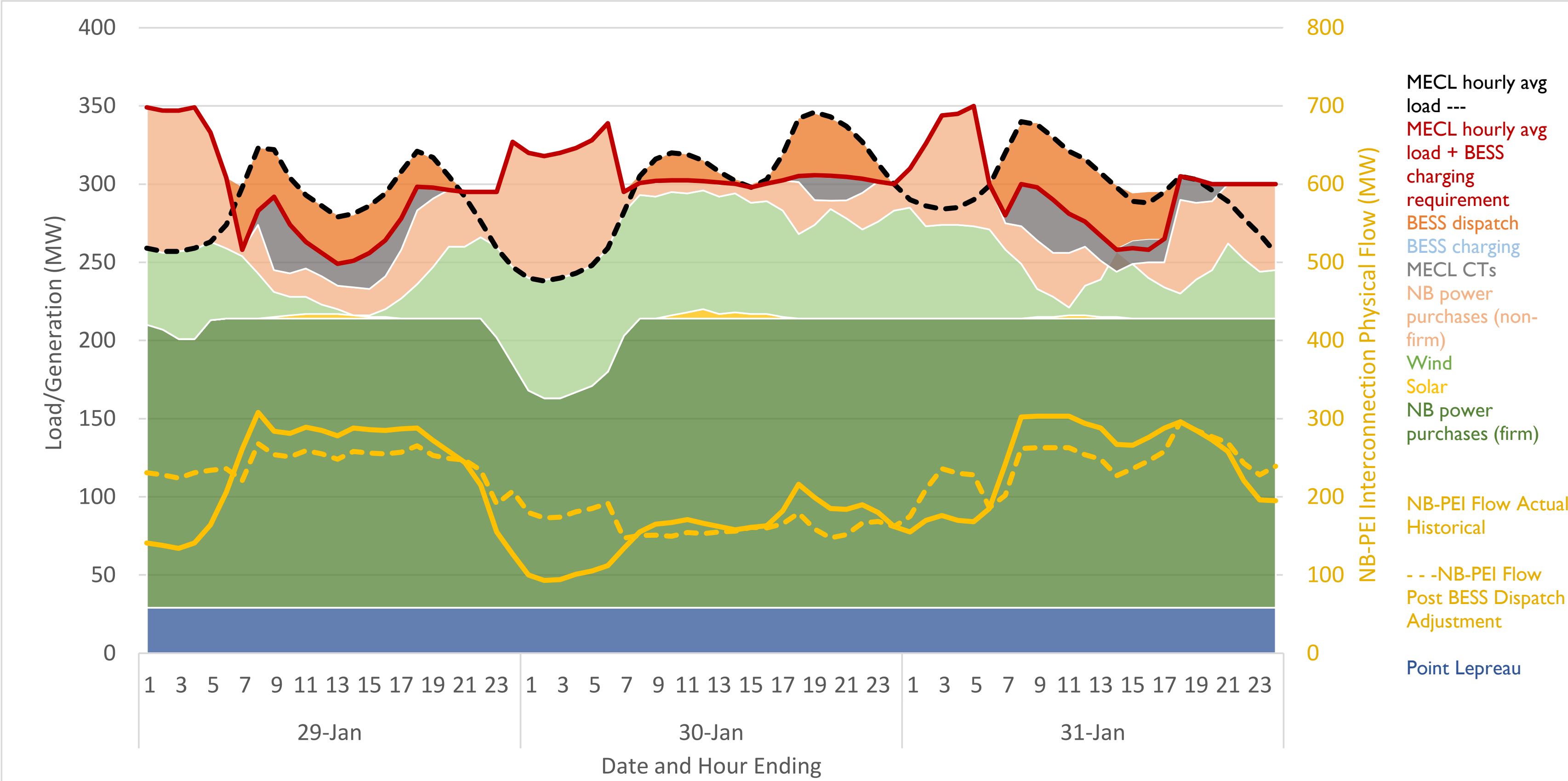
111 Lepreau (29) plus firm (185) plus non-firm (70) equals 284 MW.

112 See MECL response to Synapse IR-2 c (second set) and MECL response to IR-2d (first set) with data on physical interconnection flows between NB and PEI.

113 MECL response to Synapse IR-19 (first set) data provided the physical hourly flows between NB and PEI for this period.

**Figure 6. Illustration of New Brunswick Energy Flow Curtailment Risk Reduction with BESS Operation**




*Source: Synapse re-dispatch of resources on 1/29-25 through 1/31/25, based on MECL data in response to Synapse interrogatory IR-19 attachment "Synapse-IR-Responses-in-Excel.xlsx," May 16, 2025. Note: "Wind" is MECL wind, while non-firm NB power purchases may include purchases from on-Island wind to which NB Power has entitlements. The two yellow lines on the bottom part of the graph are the actual NB-PEI physical flows, and an adjustment to those flows to represent reductions (during battery discharge) and increases (during battery charging).*

The two examples provided above are intended solely as an illustration of the fundamental dispatch pattern changes that can be used when a BESS resource on PEI is available to MECL and NB Power system operators. The examples are not meant to convey the "right" solution for this example period (actual load and supply conditions for the January 29–31, 2025 period), or any particular period. As we recommend, MECL should conduct a more thorough and systematic assessment of the optimal use of a BESS resource. In particular, MECL should analyze how ongoing and projected conditions over the next planning period (5, 10, or 20 years), considering longer-term changes to load and supply resource availability, would result in different operational approaches to BESS resources on the MECL grid.

### Battery Storage Performance During Extreme Events

Battery storage system performance during an extreme event - such as occurred in February 2023 – would be a refinement of the patterns seen in Figures 5 and 6 and would be based on the actual and predicted conditions at the time of the event. Those conditions would include, especially, the status of on-Island wind resources, availability of other on-Island capacity, the predicted load, and the availability of both import energy and the interconnection cable and associated transmission system capability. The most important attribute a BESS resource contributes during an extreme event is its flexibility and responsiveness as a dispatchable resource.

Presumably, MECL (in combination with NB Power) would have a detailed operational protocol in place for extreme event conditions, reflecting the flexible characteristics of the BESS resource if on-Island battery capacity were installed. Such protocols would explicitly include the BESS resource duration parameter and allow for charging when system resources (on or off-Island) are available after periods of discharge.

The batteries would likely charge in advance of expected extreme cold temperatures, for example, either from on-Island wind if or as available, or from import availability in advance of the event. The batteries would be used (i.e., discharged) to reduce the need for import energy during the times when predicted import availability is lowest; or a portion (or all) of the battery capacity could be held as operating reserve, for instantaneous use to make up a shortfall upon loss of a capacity resource or a partial (or full) disconnection event. The battery would continuously provide system support as an ancillary services (operating reserves, frequency support) and energy provider, or potentially in charging mode if the on-Island wind resource output was high (as seen in Figure 2-3 (page 1) of S&L's Extreme Weather Event Capacity Impact report, wind output was on PEI was at 160 MW on the afternoon of February 3, 2023). Nova Scotia Power reported on the status of its new battery energy storage resources during the January 23-26, 2026 cold weather event in the Maritimes.[114]

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[114] See Nova Scotia Power's report under Matter M12694, at https://uarb.novascotia.ca/fmi/webd/UARB15. "The NS Power BESS currently consists of two sites (99W Bridgewater, 132H Spider Lake) with a combined output capability of 100 MW for up to four (4) hours. With the reduction of forecast wind generation and in anticipation of the tight supply situation over the evening system peak, the batteries were maintained at a state of full charge until approximately 16:20 on January 25 when they began discharging energy back onto the grid. Battery output

## On-Island Capacity Balance and Cost for Alternative BESS Scenario

In this section we illustrate the capacity balances and a comparative measure of the annual capacity costs of the proposed 100 MW CT scenario versus alternative 100 MW BESS capacity scenarios (4- and 6-hour durations). The comparative measure of the annual capacity cost is the cost of the new on-Island capacity resource, plus the cost of the required remaining New Brunswick firm import purchases necessary to meet resource adequacy obligations. The firm capacity is balanced across the three scenarios to allow a level cost comparison.

Notably, this capacity cost comparison does not include net effects from energy costs associated with each of the scenarios. As we have noted, we expected BESS scenarios to result in net annual energy benefits relative to the CT scenario.

MECL has not sufficiently explored the cost comparison for alternatives to purchasing 100 MW of new CTs. Alternative portfolios can satisfy MECL's and PEI's top two priorities: (1) maintaining on-Island capacity at roughly 50 percent of winter peak needs, and (2) meeting at least 115 percent of future winter peak gross loads. The three scenarios below outline the base case and two potential alternatives that would allow MECL to meet its capacity needs.

- **Scenario 1 – MECL's proposed portfolio**. This scenario includes 100 MW of new CTs installed in 2028. It also assumes an additional 50 MW of CTs replaces the Borden CTs one-to-one in 2032.
- **Scenario 2 – New BESS – 6 Hour**. This scenario includes 100 MW of new 6-hour BESS installed in 2028 (instead of the proposed 100 MW CT). An additional 50 MW of CTs replaces the Borden CTs one-to-one in 2032.
- **Scenario 3 – New BESS – 4 Hour**. This scenario includes 100 MW of new 4-hour BESS installed in 2028. An additional 50 MW of CTs replaces the Borden CTs one-to-one in 2032. NB Power firm purchases are slightly higher in this scenario, to reflect the lower ELCC likely to be considered for the 4-hour resource, to meet capacity obligations.

The capacity balance table shown below reflects the overall capacity supply resource needed to meet MECL requirements through 2033. The capacity cost shown in the following graph reflects only the capacity cost associated with the new on-Island resources, plus the required purchase of New Brunswick firm capacity to make up the remaining need to meet capacity obligations. This almost provides an apples-to-apples cost comparison across the alternatives considered; but it excludes net energy benefits that would accrue to the BESS scenarios.

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was adjusted in response to fluctuations in generation, the Onslow South Corridor flow and system voltage in the Metro and West regions, and to augment the Metro dynamic reactive reserves. Over the course of the evening peak, the BESS provided 230 MWh to the grid and substantial VAR support to maintain system voltages during the period of high system loading. The available state of charge of the batteries also contributed to operating reserves and assisted in reserve recovery. … The addition of BESS was beneficial during the event, providing capacity and reactive power peak support over peak load periods." Report, pages 21 and 23.

We note that many different permutations could be considered to meet capacity needs. In this report we simplify consideration of the 100 MW CT proposal by placing it in direct comparison to a specific reasonable resource type option currently available. As we further recommend, an updated Integrated System Plan exercise is required to more fully allow for all energy and capacity considerations for MECL's new infrastructure investments.

***MECL Capacity Balance with New On-Island Capacity Resources – CT and BESS Scenarios***

For either the CT project or the BESS alternative, the capacity balance will reflect NB Power's required resource adequacy obligations including MECL's committed capacity purchases and on-Island capacity resources. Table 4 below shows the projected capacity balance for the CT scenario, and for alternative 100 MW BESS scenarios, for the period through 2033. For this summary, we assume the 6-hour BESS resource provides the same level of firm capacity as the CT resource (i.e., ELCC=1.0 for both). The 4-hour BESS resource is assumed to provide 90 percent of the capacity of a 6-hour BESS resource (ELCC=0.9).

For all scenarios, additional capacity from demand-side peak load reductions, the Pt. Lepreau contract, existing wind resources, and existing CT resources contribute to meeting MECL's needs, which are at least 115 percent of its peak load. Table 5 shows each scenario's on-Island capacity as a percentage of winter peak load, which is the same (in each year) across the three scenarios.

Table 4. Alternative Resource Portfolios for PEI (2024-2033) – Nameplate Capacities (MW)

| Year | NB power purchases [(1)] | | | New CT | | IL + DSM [(2)] | BESS - | | Wind [(3)] | Pt. L. [(1)] | Existing CTs | Peak Winter Load |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | S1 | S2 | S3 | S1 | S2 and S3 | All | S1 | S2 and S3 | All | All | All | All |
| **2024** | 190 | 190 | 190 | 0 | 0 | 14 | 0 | 0 | 203 | 29 | 89 | 314 |
| **2025** | 185 | 185 | 185 | 0 | 0 | 14 | 10 | 10 | 203 | 29 | 89 | 350 |
| **2026** | 190 | 190 | 190 | 0 | 0 | 17 | 10 | 10 | 233 | 29 | 89 | 363 |
| **2027** | 190 | 190 | 190 | 0 | 0 | 23 | 10 | 10 | 246 | 29 | 89 | 373 |
| **2028** | 190 | 190 | 200 | 100 | 0 | 28 | 10 | 110 | 246 | 29 | 89 | 383 |
| **2029** | 190 | 190 | 200 | 100 | 0 | 32 | 10 | 110 | 339 | 29 | 89 | 393 |
| **2030** | 190 | 190 | 200 | 100 | 0 | 33 | 10 | 110 | 339 | 29 | 89 | 402 |
| **2031** | 190 | 190 | 200 | 100 | 0 | 33 | 10 | 110 | 339 | 29 | 89 | 411 |
| **2032** | 190 | 190 | 200 | 150 | 50 | 34 | 10 | 110 | 339 | 29 | 74 | 420 |
| **2033** | 190 | 190 | 200 | 150 | 50 | 34 | 10 | 110 | 339 | 29 | 49 | 429 |

**Notes**

**(1) Off-island resource**

(2) Interruptible load and demand-side management (Table 9, Application, p. 44).

**(3) Reflects all existing nameplate wind on Prince Edward Island, plus requested new wind (Table 2, Application, p. 22)**

Table 5. On-island and total capacity as a % of winter peak

| Year | On-island capacity, as a % of winter peak | | | Total capacity, as a % of peak winter | | |
|---|---|---|---|---|---|---|
| | S1 | S2 | S3 | S1 | S2 | S3 |
| **2024** | 50% | 50% | 50% | 123% | 123% | 123% |
| **2025** | 44% | 44% | 44% | 105% | 105% | 105% |
| **2026** | 43% | 43% | 43% | 103% | 103% | 103% |
| **2027** | 44% | 44% | 44% | 102% | 102% | 102% |
| **2028** | 70% | 70% | 67% | 127% | 127% | 127% |
| **2029** | 73% | 73% | 71% | 129% | 129% | 129% |
| **2030** | 72% | 72% | 69% | 126% | 126% | 126% |
| **2031** | 70% | 70% | 68% | 124% | 124% | 124% |
| **2032** | 77% | 77% | 75% | 129% | 129% | 129% |
| **2033** | 70% | 70% | 68% | 121% | 121% | 121% |

Notes: For calculations of on-island capacity as a % of winter peak and total capacity as a % of peak winter load, we applied the following ELCCs to battery and wind resources.

90% ELCC applied to MECL's 10 MW of BESS (present in all scenarios).

100% ELCC applied to 6 hr batteries in S2; 90% ELCC applied to 4 hr batteries in S3

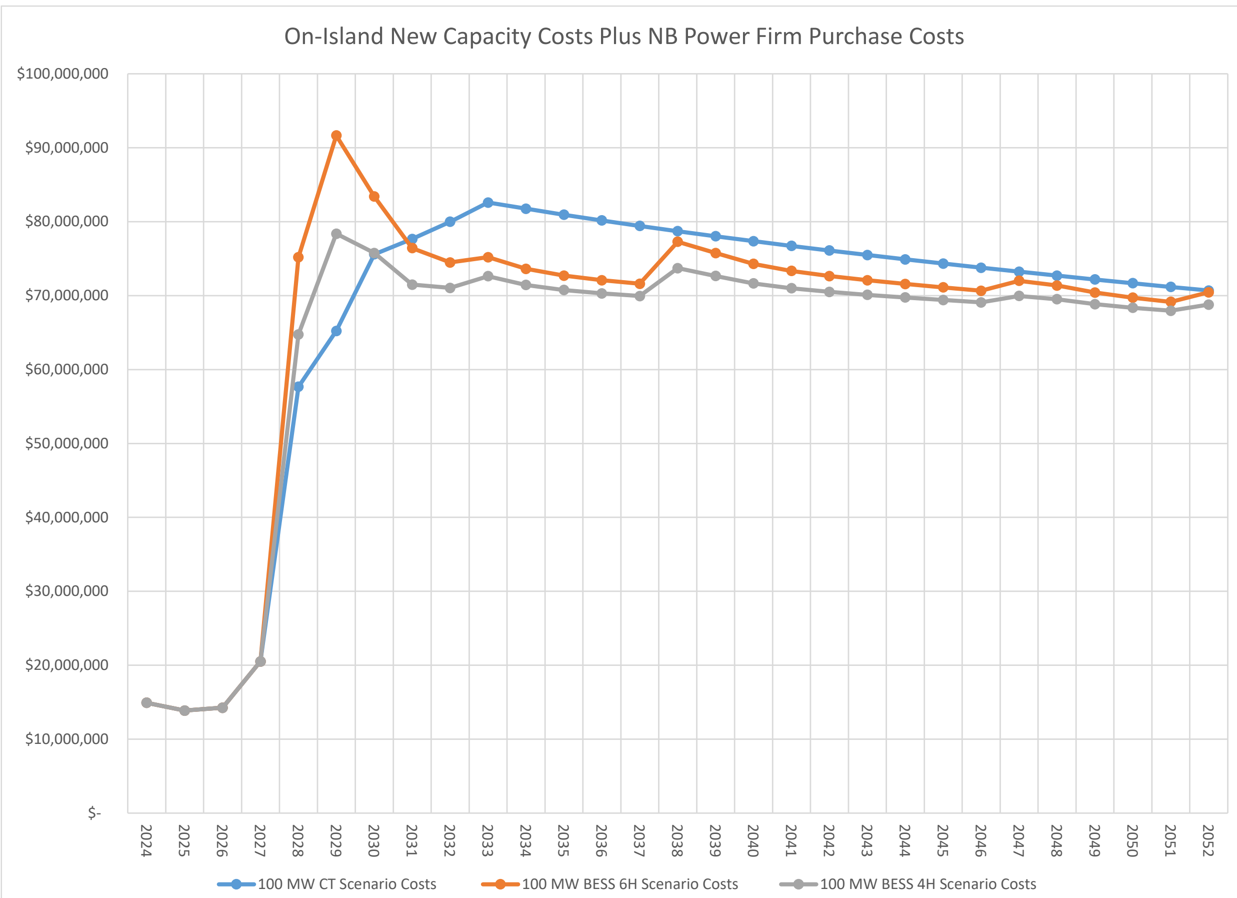
20% ELCC applied to wind total in 2024 and 2025 and 17% ELCC applied to wind total in 2026-2033 for all scenarios, to reflect average wind portfolio ELCC effects for purpose of capacity accounting.

On-island capacity as a percentage of winter peak for 2028-2033 is lower for S3 to account for 10 MW more from NB, vs. S1 or S2.

### *New On-Island Plus Remaining New Brunswick Firm Purchases Capacity Cost – CT and BESS Scenarios*

Figure 7 below shows the annual costs of the combined New Brunswick firm purchases and the new on-Island capacity for the 100 MW CT and 100 MW BESS scenarios. All other capacity costs are excluded, as they are the same across the CT and BESS new on-Island capacity scenarios. The costs were developed using MECL's methodology for recovering annual revenue requirement from new capacity sources, as shown in Appendix E of the Application and as provided in Confidential Appendix A to this report. It also uses MECL's confidential cost projection for firm New Brunswick capacity and considers the firm capacity value of the BESS resources.

**Figure 7. Annual Cost of Capacity – New Brunswick Firm Purchase Plus 100 MW of New On-Island Capacity**




*Note/Source: Excludes capacity costs common to each of the CT and BESS scenarios (Pt. Lepreau, existing CTs, existing wind, new 10 MW BESS if developed). Source: Synapse, based on MECL capacity requirements, NB Power confidential capacity cost projection, and costs of 100 MW CT and BESS (4 hour and 6 hour) resources.*

As seen in Figure 7, the pattern of annual cost recovery for the scenarios depends on the asset, and is largely driven by the tax treatment. Figure 7 shows the augmentation increases required for the BESS resource if operating on a daily cycle. It also shows a difference in the specific pattern of cost recovery in the early years, with the requirements for the BESS resources initially higher but then decreasing to levels less than the CT resource after a few years. This phenomenon is due to the Accelerated Capital Cost Allowance (CCA) treatment that applies to BESS resources, but not the CTs.[115] This incentive provides an enhanced first-year allowance for eligible property. As a result, the BESS resources have higher annual costs initially, but lower longer term annual costs relative to the CT, which has a straight line tax depreciation trajectory. As noted in the earlier portion of this report, the net present cost for the BESS resource (both 6-hour and 4-hour) is less than the net present cost of the CT resource over a 50-year lifetime assessment.

We recommend that MECL review the overall capital cost recovery framework for a BESS resource that will require augmentation (i.e., sustaining capital investment) over time, depending on its overall operational use pattern. We note that the actual amount of augmentation required will depend on the frequency of operation. The level of expected energy benefits arising from BESS resource operation will be proportional to its required augmentation needs: the more the BESS is used to obtain energy arbitrage benefits, the greater the amount of augmentation that will be required. Conversely, if the BESS resource is only used for a limited function (for instance, as a pure capacity resource with little operation for energy purposes—similar to MECL's stated use for the CT resource) then its augmentation needs will be reduced.

# 4. CONCLUSIONS AND RECOMMENDATIONS

### Conclusions

1. Based on MECL's responses to Synapse's second set of interrogatories, a 100 MW BESS resource can likely be purchased and installed by the end of 2028, providing the same timeline for increased on-Island capacity as the proposed 100 MW CT project. The proposed 100 MW CT project is thus not the only viable option for provision of on-Island capacity in the nearest possible timeframe.

2. The current market pricing conditions for the proposed 100 MW ProEnergy CT project, MECL and S&L's current estimates for the cost of BESS resources, and an estimate for the increased costs associated with a 6-hour vs. a 4-hour duration BESS project allow us to draw reasonable conclusions when comparing costs across resource options. Relative installed costs have changed considerably since 2022, and BESS resources are now less expensive than equivalent CT resources.

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[115] Clean energy investments that are acquired after 2018 and available for use before 2028 can qualify for the accelerated CCA treatment. See: https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/sole-proprietorships-partnerships/report-business-income-expenses/claiming-capital-cost-allowance/accelerated-investment-incentive.html

A 100 MW 6-hour duration BESS resource has a roughly 6 percent lower installed capital cost (at $314 million) than the alternative 100 MW CT project for which MECL is requesting approval (at $334 million). A 100 MW 4-hour duration BESS alternative has a 30 percent lower installed cost (at $233 million) than the 100 MW CT option because it requires less energy storage (than the 6-hour resource) to accompany the same 100 MW capacity output capability.

3. Based on NB Power's 2023 IRP estimate of the ELCC value of BESS resources, the ELCC value of the first 100 MW of utility-scale 4-hour duration BESS resource installed on MECL's system (given no BESS resources currently on NB Power's system) is likely relatively high, at or above 0.9. This indicates that a 100 MW 4-hour BESS resource would reduce the need for capacity procurement from NB Power by at least 90 MW, for the purpose of meeting resource adequacy requirements. For a 6-hour BESS resource, the ELCC can be considered 1.0 and it would fully replace 100 MW of capacity procurement from NB Power to meet capacity adequacy obligations. It is unclear if the 100 MW ProEnergy CT proposal would also merit a 100 percent resource adequacy contribution, since it does exhibit a forced outage rate of roughly 4 percent, and generally in other jurisdictions CT resource capabilities for the purpose of meeting resource adequacy obligations are often lower than 100 percent, by roughly the value of the forced outage rate.

4. Correcting for the resource adequacy value of the BESS and CT options, either of the 4-hour or the 6-hour BESS resource option is less expensive than the CT option on a per-MW installed cost basis for on-Island capacity provision.

5. Using MECL's ratemaking framework for net present cost estimation, the net present cost (NPC) of the 100 MW CT alternative is $411 million for a 50-year useful life period. Using MECL's 20-year useful life framework for the 4-hour BESS resource, and excluding any value remaining after year 20, the NPC is $280 million.

   Using the same MECL accounting framework as used for the CT project and extending MECL's augmentation approach for the BESS resource useful life to reach 50 years (i.e., augmentation in years 21, 26, 31, 36, 41, and 46 in addition to year 11), the low end of the projected net present cost of a 4-hour 100 MW BESS resource, corrected for required augmentation to reach a 50-year useful life, is $292 million.

   Under two other projections of augmentation and replacement cost for the 4-hour BESS resource, the net present cost is seen to be either $326 million (medium), or $375 million (high). For a 6-hour BESS resource, the NPC for a 50-year useful life is $386 million using the medium augmentation and replacement approach.

   Thus, either the 4-hour or the 6-hour 100 MW BESS resource option is less expensive on a net present cost basis than the 100 MW CT proposal for equivalent useful lives.

   Extending the accounting framework for the BESS resource to one equal to the CT project (i) allows the full value of the declining real cost trajectory for BESS resources to be captured, (ii) recognizes that only a portion of the original BESS investment is more steeply degraded due to use (the energy storage component) compared to other components, and (iii) reflects the effect of the time value of money.

6. The installed cost basis and the net present cost basis for the resource capacity in the above conclusions do not include additional value premium associated with operating the BESS resource. The BESS resource can reduce the effective cost of some of the energy procured from NB Power through “time shifting” of procurement. The BESS resource can also be operated to avoid energy costs from generating electricity using on-Island CT resources, whose marginal or operating costs are much higher in general than average procured energy from NB Power.

7. Energy arbitrage potential is not based on an annual average difference in overall ISO NE-defined on-peak and off-peak energy periods. Energy arbitrage potential from a 6-hour or a 4-hour BESS resource exists because of the variability of *daily* energy price patterns, across different hours for battery charging and discharging purposes.

   While *some* days do not see much price variation, based on the November 2024 to October 2025 price patterns at the ISO NE NB external node, 54 winter days and 138 total days *do* exhibit price differentiation that illustrate the potential for cost-effective arbitrage opportunities valued at least as roughly $1 million to $2 million per year, based on 2025 patterns. As PEI load and on-Island resource scenarios change, and over time as the NB and ISO NE systems change, the arbitrage opportunities will also likely change.

8. Both CT and BESS resource options fully support the primary use cases for on-Island capacity need (peaking and backup capacity response to unplanned events, hold-to-schedule directive, and facilitating maintenance). Neither on-Island capacity alternative fully protects against a lengthy full (or lengthy severe partial) disconnection event, nor are they intended to. Both options mitigate loss-of-load concerns under either full or partial-disconnection events. Both options support the secondary use case considerations for voltage support and other ancillary service needs, and transmission contingency support during high load conditions.

9. Both resource options reduce the risk of curtailment of New Brunswick energy flows during tight conditions. A 100 MW 6-hour or 4-hour duration BESS alternative can reduce the risk of curtailment of New Brunswick imports during the riskiest winter periods by providing a critical ability to time-shift energy flows sourced either from on-Island resources (especially wind) or from New Brunswick imports or on-Island New Brunswick energy entitlements (non-MECL wind on-Island).

   A 100 MW BESS alternative effectively transforms a peak hour or hours reliability concern into a more easily managed daily energy concern by allowing for such energy time-shifting. A 6-hour BESS resource represents a more robust ability to mitigate the curtailment risk than a 4-hour BESS resource, at an increase in installed costs.

10. MECL has not comprehensively, or sufficiently, analyzed the costs and benefits for a 100 MW BESS alternative to the proposed CT project. Particularly, MECL has not evaluated the ongoing or near-, medium- and longer-term energy provision implications for ratepayers under different on-Island capacity type increases. Any significant capital expenditure for on-Island capacity increase will have near-, medium-, and longer-term implications for energy costs and meeting PEI provincial policies for GHG emission goals. These implications should be directly considered prior to any project approval.

The analytical elements required to comprehensively examine the costs and benefits of a BESS alternative to the proposed project include a considered assessment of the two main components of electricity costs: energy, and capacity. MECL's application, and this report, have been focused primarily on the capacity component. The BESS alternative is inherently tied to energy considerations – MECL's failure to sufficiently address these energy considerations is the primary shortfall of its analysis in this application.

A third element to consider is a metric associated with MECL's contribution in support of Prince Edward Island's progress toward meeting its sustainability goals. While there are a number of ways this could be achieved, one straightforward metric to consider is the overall emissions associated with the total energy needs in each year, computed based on the source of energy.

In summary, we characterize these three elements as follows:

- **Energy**. A twenty-year forward projection of the total energy requirements to meet load, and the associated costs MECL will incur for this energy. This should include the sources, generation types, and location (on or off-Island). In particular, the exercise needs to carefully assess the value of significant increases in on-Island wind energy (vs. the alternative of NB import energy and increases in fossil-fueled on-Island generation). It must also consider the cost and timing of energy procured from New Brunswick, which would be different from current patterns if on-Island battery storage was present to better optimize such purchases.
- **Capacity**. The same twenty-year forward projection of the total capacity costs required to meet the load. Generally, these are the costs that have been addressed in this report. The results of any market-faced effort to determine the BESS-alternative costs (such as RFP results) would be needed to improve the accuracy of the estimates used by MECL thus far for BESS resources.
- **Emissions**. The total emissions associated with the energy sources, including recognition that import energy from New Brunswick carries an emissions burden depending on the timing (season, hour of the day, etc.) of the import quantities. On-island energy source emissions can be directly computed.

While a production cost exercise using standard industry models and software might be required to precisely estimate these values, such as would be reflected in a new Integrated System Plan, a simpler spreadsheet-based "scenario comparison" exercise would suffice to more quickly gauge the energy and emission components noted here, in addition to the capacity costs considered in this report.

11. Proceeding with the proposed CT project absent comprehensive cost and benefit analysis of viable, timely alternatives—including energy effects—would be economically imprudent, because a large on-Island capacity addition has direct implications for future energy costs for MECL. A large on-Island capacity addition also has direct implications for how MECL's system would contribute to meeting PEI GHG and net-zero emission goals.

12. Existing on-Island wind energy improvements since the February 2023 weather event (made to the set of resources that were low-performing during that event) indicate that even greater capacity and energy injection value is reasonably likely during similar events. MECL's response to Synapse IR-14 and IR-15 (first set) confirms this, including the statement "Based on the information provide by wind farm operators on PEI, most PEI wind farms are now believed to be well positioned to maintain operation during extreme cold weather events such as the February 3 to 5, 2023 polar vortex." Figures 2-3 and 2-4 of the S&L Study (July 2023) show a roughly 100 MW drop in PEI wind generation output while wind speeds remained high, as temperatures dropped. This drop persisted for at least a 24-hour period while winds remained high.

13. The presence of on-Island wind energy resources that exhibit high output performance correlated with low temperatures and higher peak load—at times of highest New Brunswick energy curtailment risk—is a synergistic benefit for PEI electricity systems. MECL should more fully and carefully examine these synergies in the context of a need for a new Integrated System Plan.

    A BESS resource option leverages these synergies by allowing MECL to (1) more effectively utilize PEI wind energy during the intervals it is most needed, and (2) store energy as needed (for later use) during the periods in which wind output is high or at a maximum, or New Brunswick import energy is more readily available or less expensive. Grid-forming BESS resources also allow PEI wind to operate fully during a disconnection event.

14. Having the option of procuring NB Power energy with time-differentiated pricing is a sensible economic attribute in general, and doubly so for a system with BESS resources. BESS resources can allow MECL to better control the hourly schedule of energy needs from New Brunswick Power and account for pricing that can vary by the hour.[116]

15. The presence of a BESS resource allows reduced operation of existing and/or new CTs on the island because BESS resource dispatch can fully eliminate the use of CT energy to accomplish the "hold to schedule" requirements of NB Power. A BESS resource in grid-forming mode can provide the full range of ancillary services required for frequency and voltage and stability needs during a disconnection event as needed.

## Recommendations

1. The request for capital cost approval of the ProEnergy CT project should be denied, pending a more comprehensive analysis of the cost of a battery alternative obtained through the results of an RFP or RFI (request for information) to fully inform an estimate of the current market costs of such an alternative. Less expensive BESS capacity

[116] S&L in the Capacity Resource Study at pages 23-25 implied that MECL would need to be part of ISO NE in order to obtain access to hourly pricing. MECL during the September 2025 technical conference indicated that it is considering hourly pricing with NB Power in its new energy marketing agreement. We believe S&L is incorrect that MECL must be part of ISO NE in order to obtain opportunity cost energy pricing from NB Power on an hourly basis. It is not our understanding that MECL would need to be part of an ISO in order to accomplish this, and MECL's comments at the technical conference appear to confirm this. We assume that NB Power Energy Marketing, with whom MECL contracts for energy, has direct access to hourly pricing as reflective of the opportunity cost of hourly energy flows to PEI.

resources will provide at least the same on-Island capacity as the CT project, and they can provide additional, synergistic short- and long-term benefits (energy and GHG emission reduction, support for integration of more on-Island wind) while reliably meeting the use case need.

2. MECL should rapidly undertake an RFP or RFI process to consider installation of 100 MW of 4-hour or 6-hour BESS capacity. This will provide MECL and the PEI IRAC up-to-date information on the direct, likely costs of installation of an alternative capacity resource option.

3. MECL should continue to negotiate the new (post-2026) energy procurement agreement with NB Power and directly consider how to include a form of hourly energy pricing for at least some of the contracted energy. This form of pricing will be critical to allow MECL to capture the benefits of procuring needed energy from NB Power as often as possible during lower-price energy cost hours.

4. A new, comprehensive ISP is required to allow MECL to analyze resource adequacy needs and options for the near- and longer term. We recommend MECL stage such an analysis, with priority given first to reviewing the role that an initial on-Island BESS resource would play to meet near-term reliability needs and contribute towards meeting a 50 percent on-Island capacity needs target. The analysis must include the energy effects associated with BESS resource alternatives, and it must include the role wind energy will play in meeting larger portions of MECL's retail load.

5. Any new ISP must fully consider the role that advanced demand-side management initiatives can play in reducing peak load during both normal winter peak periods and also during extreme event periods when loads are extremely high and/or curtailment risk from New Brunswick is particularly high. This analysis must consider using best practices[117] to ensure peak load reduction from the transportation and heating sector through use of enabling technologies and in recognition of MECL's rollout of AMI capability.

6. MECL should report to the PEI IRAC on its plans to directly contribute towards PEI meeting its sustainability targets through increased MECL procurements of on-Island wind energy, and planned reductions in procurements of New Brunswick energy. This should be coordinated with its analysis in a new ISP, and in direct recognition of the synergies present in on-Island wind and considered BESS resource deployment.

[117] See the most recent Dunsky demand-side management reports for Prince Edward Island.

# APPENDICES

**Confidential Appendix A** (to be provided separately)

Net Present Cost Computations for BESS Resource with 50-Year Useful Life

**Appendix B – Grid Forming Battery Reference Attachments**

1. Energy Systems Integration Group (ESIG) and GridLab

Brief for Decisionmakers: Grid-Forming Battery Energy Storage Systems, A Call to Action for a Stable Energy Transition, March 2025

2. North American Electric Reliability Corporation (NERC)

White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems, September 2023