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The Island Regulatory and Appeals Commission

January 28, 2026

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

Dear Ms. Bradley:

Response to Interrogatories from the Prince Edward Island Energy Corporation On Island Capacity for Security of Supply Project (UE 20742)

Please find attached the Company's responses to interrogatories from the Prince Edward Island Energy Corporation with respect to the On-Island Capacity for Security of Supply Project Application filed with the Commission on December 18, 2024.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

Gloria Crockett
Director, Regulatory & Financial Planning

GCC04
Enclosure

Via Email: ctweedy@gov.pe.ca
racollier@gov.pe.ca

January 28, 2026

Richard A. Collier & Christiana Tweedy
Lawyers for the Added Party Intervenor
Prince Edward Island Energy Corporation
PO Box 2000
Charlottetown PE C1A 7N8

Dear Mr. Collier & Ms. Tweedy:

Response to Interrogatories from the Prince Edward Island Energy Corporation On Island Capacity for Security of Supply Project (UE 20742)

Please find attached the Company's responses to interrogatories from the Prince Edward Island Energy Corporation with respect to the On-Island Capacity for Security of Supply Project Application filed with the Commission on December 18, 2024.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

Gloria Crockett
Director, Regulatory & Financial Planning

GCC05
Enclosure

RESPONSES TO INTERROGATORIES
FROM
PEI ENERGY CORPORATION

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

Submitted January 28, 2026

PEI Energy Corporation ("PEIEC"), in its capacity as an Added Party Intervener in the Application Requesting Approval for On-Island Capacity for Security of Supply Project (the "Application"), submitted by Maritime Electric Company, Limited ("MECL"), requests responses to the following interrogatories:

IR-1 NS Power has included a significant amount of Battery Energy Storage System ("BESS") into their 10-year system plan and recently NB Power ("NBP") launched a procurement process for adding BESS to their system. NBP is the effective systems operator for PEI. Please outline the discussions that have taken place over the past two years regarding BESS opportunities for PEI.

Response:

Over the past several years, Maritime Electric Company, Limited ("Maritime Electric" or the "Company") has spent considerable time investigating Battery Energy Storage System ("BESS") technologies and their applicability to the Company's electrical system. This work has included consultations with battery developers, consulting engineers, other utilities, and industry groups to understand how a BESS could be effectively used on Prince Edward Island ("PEI"). Accordingly, the Company included a 10 megawatt ("MW")/4-hour demonstration BESS in its December 2024 Application to better understand how energy storage could support a portion of future capacity needs and other system requirements on PEI. Guidance from Sargent and Lundy ("S&L") emphasized the value of such a demonstration project, while also noting that BESS technologies, serving as capacity resources, continue to exhibit limitations that must be carefully considered.

As noted in the Company's cover letter to Synapse Energy Economics, Inc. ("Synapse") interrogatory responses (Exhibit M-15) filed on November 12, 2025, a BESS offers three primary use cases in the electric utility industry: (i) energy arbitrage; (ii) ancillary services; and (iii) as a capacity resource. Under PEI's current market structure, cost-saving energy arbitrage provides negligible value due to fixed energy pricing, and ancillary service benefits diminish beyond approximately 12.5 MW. When used as a capacity resource, a BESS can contribute to meeting peak demand, but only to the extent demonstrated through its effective load carrying capability ("ELCC"). ELCC represents the portion of a resource's nameplate capacity that can reliably contribute to meeting peak demand, reflecting the operating characteristics and duration limits of the BESS as well as overall system characteristics. Accordingly, ELCC must be studied to determine how much of a proposed BESS could be counted as firm capacity on PEI.[1]

NB Power recently issued a request for proposals ("RFP") for a 50 MW/4-hour BESS. However, the appropriate scale of a BESS project is inherently tied to the size of the electrical system it serves. NB Power's historic peak demand is roughly ten times larger than Maritime Electric's.[2] This means that a 50 MW/4-hour BESS for NB Power is proportionate to a 5 MW/4-hour BESS for Maritime Electric, which is half the size of the 10 MW/4-hour installation proposed in Maritime Electric's December 2024 Application.

1 A BESS sized in excess of what could be counted as firm capacity does not address Maritime Electric's capacity deficit and is, therefore, outside the parameters of what this current regulatory proceeding is addressing.
2 NB Power's historic peak demand (i.e., load plus losses) is 3,394 MW versus 359 MW for Maritime Electric.

Applying the same proportional lens to Nova Scotia Power ("NS Power"), whose system is approximately six times larger than Maritime Electric's,[3] NS Power's plan to add 400 MW of BESS would correspond to roughly a 60 MW BESS on the Maritime Electric system. NS Power has also published ELCC values for its planned BESS additions: the 400 MW BESS portfolio is expected to provide 181 MW of ELCC, which on a relative basis equates to approximately 27 MW of effective capacity for Maritime Electric.

These comparisons underscore that while a BESS can be a functional component of a modern grid, its use as a capacity resource has limitations. When comparing Maritime Electric's proposed BESS to those proposed by NB Power and NS Power you must consider the size of their respective electrical systems. As demonstrated above, Maritime Electric's proposed 10 MW BESS is within range, on a proportional basis, to that proposed by NB Power and NS Power.

3 NS Power's historic peak demand is 2,455 MW versus 359 MW for Maritime Electric.

IR-2 MECL, as a customer of NBP, should be part of the overall supply and demand planning for the area. Please demonstrate how your project fits well with the plans of NBP? How can you demonstrate that you have conducted recent meaningful discussions with NBP?

Response:

Maritime Electric maintains regular meetings with NB Power on a wide range of operational and planning matters, including discussions related to energy supply and capacity requirements. These meetings ensure coordination on interconnection usage, contingency planning, and system reliability, particularly during peak demand periods. However, each utility is responsible for conducting its own independent supply and demand planning to meet the reliability and capacity requirements of its respective service territory.

This proposed 100 MW Accelerated On-Island Capacity Development Solution (“Accelerated Capacity Solution”) is aligned with NB Power’s system planning objectives, as evidenced by the fact that both utilities have identified the same technology, and even the same supplier, as the most effective solution to address emerging capacity deficits. NB Power approached Maritime Electric nearly a year ago to explore the possibility of joint participation in its Renewable Integration and Grid Security (“RIGS”) project, recognizing that this solution could also meet a portion of Maritime Electric’s capacity deficit. NB Power’s decision to reach out as soon as it decided to pursue the RIGS project demonstrates the strength of the relationship and the depth of collaborative planning between the two utilities. This partnership has been a cornerstone of system reliability since PEI was first interconnected with the NB Power system in 1977 and continues to underpin meaningful regional planning today.

Furthermore, meaningful discussions are demonstrated by NB Power’s continued commitment to maintain 190 MW of firm capacity for Maritime Electric through the term of its published resource adequacy outlook, as NB Power addresses its own capacity challenges.[4] NB Power has not reduced this allocation, which underscores the collaborative nature of planning between the two utilities and Maritime Electric’s confidence that the Accelerated Capacity Solution aligns with regional reliability objectives.

Accordingly, while Maritime Electric’s planning process remains independent, the proposed project reflects a shared regional understanding of the urgency and suitability of dispatchable generation to maintain system security.

[4] NB Power RIGS Application Appendix A - Resource Adequacy Report shows “Export load capacity contracts” remaining constant up to 2030. Page 6 Table 1.

IR-3 Has there been a request to the New Brunswick Transmission System Operator for conditional firm transmission related to the gas combustion turbines ("CT") project scheduled for Centre Village? Access could provide additional capacity for PEI. Such a request would trigger a system impact study and determine availability of firm transmission. If so, please provide details regarding this request and resulting system impact studies or other information arising therefrom. If no request has been made, explain why not.

Response:

Yes, a request for conditional firm transmission capacity associated with the RIGS project was submitted to NB Power in July 2025, by New Brunswick Energy Marketing ("NBEM") on behalf of Maritime Electric.[5] The specific request is to increase the import limit from 300 MW to 350 MW, which will be contingent on the RIGS facility generating electricity or operating in synchronous condensing mode.[6]

It is important to note that this conditional firm request applies solely to transmission capacity and does not include any firm generation capacity. If Maritime Electric is successful in securing the requested conditional firm transmission capacity, then the Company would still need to secure firm generating capacity to address the capacity deficit. Maritime Electric currently contracts 190 MW of firm generating capacity from NB Power, along with an additional 29 MW from the Point Lepreau Nuclear Generating Station, for a total of 219 MW.

This conditional firm transmission capacity request is intended to provide temporary relief from current import limitations until NB Power implements the necessary system upgrades to support higher year-round transfer levels to PEI. Although the request has been formally submitted, the associated system impact study has not yet been completed. As a result, Maritime Electric does not have the final results or conclusions of that study at this time.

5 NBEM currently holds the firm transmission rights to PEI on behalf of Maritime Electric. This current arrangement made it more appropriate for NBEM to make the conditional firm request.

6 The current 300 MW import limit for PEI is primarily constrained by insufficient reactive power support within the NB Power system, particularly in the Moncton area, which restricts higher transfer levels across the NB–PEI interface. When the RIGS facility is generating or operating in synchronous condensing mode, it will provide additional reactive power support, thereby enabling higher import capability into PEI.

IR-4 There appears to be a short timeframe from the time a deposit is placed with ProEnergy and a finalized order is required. What are the next steps and timelines that will be carried out once a decision is reached on the deferral account? Please provide a response for both positive and negative outcomes.

Response:

In order to maintain alignment with NB Power's RIGS project, a decision on the Accelerated Capacity Solution must be made as soon as possible. It should be noted that NB Power has already secured its manufacturing slot with ProEnergy for the RIGS project, ensuring a confirmed position in the production schedule and securing the price.

Once a regulatory decision is received on the requested deferral account, the next steps are summarized as follows.

> **If the deferral account is approved as filed:** Maritime Electric would immediately finalize commercial arrangements with ProEnergy, thereby securing the manufacturing slot and the price. Maritime Electric would also initiate the engineering design, which is necessary for the installation of the units, and secure critical components to maintain schedule integrity.
>
> Upon finalization of the commercial arrangement with ProEnergy, payments will be made as laid out in the Slot Reservation Agreement, which requires three progress payments within the first four months of signing and the next progress payment is required in month number 12. The Company believes that it is possible to complete a fulsome regulatory review in that timeframe. Further details on this scenario were provided in the Company's response to IR-11 from the Island Regulatory and Appeals Commission ("IRAC" or the "Commission") Staff filed on January 15, 2026.
>
> **If the deferral account is denied:** Maritime Electric would revert to the December 2024 Application, in which case it is estimated that the in-service date of new generating capacity would be 2031 at the earliest. In addition, the Class 4/5 cost estimate provided at that time would be more than a year old.

Maritime Electric emphasizes that the urgency of this decision cannot be overstated. The current capacity deficit is growing, and regional supply constraints mean that neighbouring utilities cannot be relied on to provide relief. Timely approval is critical to ensure that PEI customers have a secure and reliable electricity supply.

IR-5 The August 14, 2025, Supplemental Filing (Exhibit M-12) noted that the first slot reservation payment was due in September 2025 and subsequent payments due by December 1, 2025. We recognize that these dates have passed. What impact has the delay in slot reservation payments had on the proposed project, including cost and timeline? What is the revised timeline for the slot reservation payments?

Response:

To date, the original manufacturing slot with ProEnergy continues to be available and timely IRAC approval would secure the original in-service timeline of 2028. However, ProEnergy continues to indicate that interest in their combustion turbine ("CT") packages remains strong.[7] Therefore, the original manufacturing slot will not be available indefinitely.

NB Power has indicated that regulatory approval prior to April 2, 2026, is necessary to maintain its contractual position with ProEnergy, and if approvals are not secured by that date, ProEnergy may reallocate the manufacturing slot to other customers.[8] As noted in the Company's response to IR-4, NB Power has already secured both its manufacturing slot and associated pricing protections through executed agreements with ProEnergy.

With respect to project cost, ProEnergy submitted a fixed-price proposal on June 13, 2025; however, the proposal did not specify a validation period. Market conditions suggest that demand for CTs may increase the cost. Regulatory approval to proceed with the execution of an agreement with ProEnergy will result in an accurate update on the cost of this project.

With respect to the timeline for the slot reservation payments, the time between each required payment remains the same. For example, as reiterated in IR-4, the first three payments are required with four months of signing a contract with ProEnergy and the next progress payment is required in month number 12.

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7 During a January 22, 2026 update call, ProEnergy informed Maritime Electric that demand for its generating units is robust, as illustrated by a recently contracted large order. Consequently, the delivery and pricing of Maritime Electric's two units may be at risk.

8 NB Power's Motion Regarding the RIGS Schedule, filed November 17, 2025 and available on the NB EUB website - https://filemaker.nbeub.ca/fmi/webd/NBEUB%20ToolKit13 (Matter # EL-002-2025) - addresses potential impacts of the proposed hearing schedule on the RIGS project timeline. Item 7 specifically notes the requirement for regulatory approval before April 2, 2026.

IR-6 In the November 12, 2025, response to Synapse IR3-a, MECL indicates that the company is prepared to address the effective load carrying capability of BESS to determine whether it would complement a diversified energy portfolio. When will the analysis of BESS options be completed?

Response:

As indicated in Maritime Electric's response to IR-3(a) from Synapse (Exhibit M-15), the Company is prepared to assess the ELCC of BESS within diversified energy portfolios to determine whether a technically and financially viable large-scale BESS addition could complement the first 100 MW of CTs proposed in the Supplemental Filing. However, this assessment has not yet commenced.

While Maritime Electric is prepared to undertake an ELCC study for additional BESS capacity, it is important to recognize that PEI's current capacity deficit fundamentally limits the ability of a BESS to function as a reliable capacity resource. A BESS can only contribute firm capacity when it is able to discharge during peak periods, which in turn requires that it be consistently charged during off-peak periods.

As explained in IR-6 - Appendix 1, the BESS depends on a foundation of other energy resources - NB Power imports, Point Lepreau, wind, solar, and on-Island dispatchable generation - to supply the energy required to charge it before peak conditions. However, Maritime Electric is forecasting a significant and growing capacity deficit, reaching 156 MW by 2033 (representing one third of its overall capacity requirement), which means there will be insufficient surplus generation resources available to reliably charge a BESS during elevated load periods (i.e., when the capacity is needed). Without adequate on-Island capacity to establish this foundation, the BESS's ability to maintain state-of-charge and therefore provide dependable short-term capacity is severely limited. Additional dispatchable generation is required before BESS ELCC can be meaningfully increased.

The Company's immediate priority is to address the significant capacity deficit identified in the December 2024 Application. The proposed 100 MW of CTs in the Supplemental Filing represents a critical step toward achieving security of supply for customers. Even if future BESS expansion proves feasible, dispatchable generation will continue to play an essential role in meeting system reliability requirements. Accordingly, it would not be prudent to delay the current Accelerated Capacity Solution pending further study of BESS alternatives.

IR-7 The capacity filing is relying on Sargent and Lundy's analysis from 2023, which utilizes out of date load forecasts and an outdated systems plan. Given what is available today for forecasting, both for the Island and regionally, would revised information affect the underlying request? Please explain why or why not. If so, what additional revised information does MECL have in this regard?

Response:

Yes. Revised load forecasts for PEI could impact the underlying request for 150 MW of on-Island dispatchable generating capacity by increasing it. S&L recommended, and Maritime Electric has reaffirmed, an objective of maintaining approximately 50 per cent of the Company's capacity requirement in on-Island dispatchable capacity resources. As forecasts evolve, the level of required on-Island dispatchable capacity shifts correspondingly.

Since the December 2024 Application, Maritime Electric has completed its 2025 load forecast and is now working on its 2026 update. Both the 2025 and preliminary 2026 forecast updates reflect only minor adjustments that, even taken together, do not amount to a material change and therefore do not alter the conclusions of the S&L analysis.

As discussed in more detail in the response to IR-12, housing starts remain the primary driver of load growth and continue to outpace projections. Although the current forecast shows significant near-term peak load growth (i.e., increases of 11.6 per cent in 2025 and 5 per cent in 2026), these increases are largely predetermined by the elevated housing starts already recorded in 2024 and 2025. Beyond 2027, annual increases in peak load trend towards a longer-term rate of 2.4 per cent by 2034.

A further factor affecting the capacity forecast is the inclusion of controllable demand-side management ("DSM") in the Company's planning assumptions. Maritime Electric relies on forecasts provided by the Government of PEI, which is responsible for DSM program delivery. The Government's plan, originally submitted in December 2021, projected 20.5 MW of controllable DSM to be in service by fiscal year 2024/25.[9] This has not occurred. Instead, the controllable DSM component has been repeatedly deferred, and to date no controllable DSM is operational on PEI. As a result, Maritime Electric continues to shift the assumed DSM in-service date ahead by one year in each annual update. The forecasts included in the December Application still assume incremental DSM reductions in load up to 20 MW by 2032, although this outcome appears increasingly unlikely without tangible program progress.

Accordingly, while material changes to the Company's load forecasts would influence the level of recommended on-Island dispatchable capacity, small adjustments will not materially alter the required capacity and, given recent trends, forecast changes are more likely to increase projected load than reduce it. The recommendations from S&L therefore remain appropriate and continue to support the need for additional dispatchable capacity. For broader regional developments, please refer to the Company's response to IR-9.

[9] The Electricity Efficiency & Conservation Plan submitted to the Commission in 2021 forecasted 1.25 MW of controllable DSM in 2022/23, 5.25 MW in 2023/24 and an additional 14 MW in 2024/25. Commission Docket UE41401.

IR-8 Does MECL currently maintain an active Integrated System Plan ("ISP")? If so, please provide an overview of the current plan, including the generation alternatives considered and rationale for their inclusion or omission. If this information is not available, please outline how MECL intends to plan for the system in the future. Specifically, will future requests include information regarding what project alternatives were considered and how those alternatives are being evaluated against an evaluation matrix that weights items such as sustainability, emission reduction, cost, reliability, etc.?

Response:

Maritime Electric's most recent Integrated System Plan ("ISP") was issued in 2020. The Company is currently developing a new version of the ISP, scheduled for release in the second half of 2026. Based on the work completed to date on updating the generation section of the ISP, the conclusions remain consistent with those presented in the December 2024 Application.

The Company remains in a capacity deficit and, therefore, the generation section within the upcoming ISP continues to focus on addressing this deficit. The amount of capacity required and planning direction identified through the Capacity Resource Study ("CRS") conducted by S&L (filed with the Commission on February 10, 2023) remain the most appropriate and cost-effective path to meeting Maritime Electric's future capacity and reliability needs.

The CRS included a comprehensive review of existing capacity resources, an assessment of additional available resource options, and an evaluation of a broad range of alternative solutions. This analysis continues to form the foundation of the Company's integrated planning work and supports the conclusions carried forward into the updated ISP.

IR-9 In the initial December application, Table 16 outlines Forecast Capacity Shortages in Eastern North America. Since this information was gathered, several updates have been provided by the Northeast Power Coordinating Council. Is there updated information available for the Maritimes area that could provide an updated forecast? If so, please provide.

Response:

Since December 2024 there have not been significant changes in forecasted capacity shortages in Eastern North America; however, several utilities (or system operators responsible for generation planning) have released specific plans or projects intended to address the forecasted shortages. A summary of updates for each jurisdiction since December 2024 is provided below.

Quebec
Québec's 2035 Action Plan outlines Hydro-Québec's strategy to meet a projected doubling of electricity demand by 2050 through an unprecedented build-out of reliable capacity and grid infrastructure. The plan commits $155 to 185 billion by 2035 to add 8,000 to 9,000 MW of new capacity, including 3,800 to 4,200 MW of new hydro, 1,500 to 1,700 MW of wind, and 500 to 1,000 MW of solar and storage, alongside 1,600 to 1,800 MW in efficiency gains.

New Brunswick
NB Power has announced its intention to contract ProEnergy to install a 500 MW gas plant (i.e., the RIGS project) in Centre Village. As part of the evidence submitted on this project, NB Power submitted a Resource Adequacy Report that was completed in March 2024. In that report, NB Power states "in addition to this 400 MW of required generation by 2028, NB Power must also begin predevelopment work in 2024/25 for an additional 600 MW that could be needed as early as 2030."

Nova Scotia
Nova Scotia generation planning is now the responsibility of the new Nova Scotia Independent Energy System Operator ("IESO"). The newly formed IESO issued a Request for Expressions of Interest ("REOI") from interested proponents to design, build, own and operate a fast-acting power generation facility at specific sites. The REOI indicates that "to support the significant build-out of renewables across Nova Scotia, this specific IESO Nova Scotia competitive RFP will result in a tolling agreement for at least 300 MW of fast-acting generation capacity with a targeted commercial operations date before the end of 2029." That REOI had a deadline of November 21, 2025, but no results have yet been made publicly available.

Newfoundland and Labrador
Since early 2025, Newfoundland and Labrador Hydro ("NL Hydro") has advanced a major 150 MW CT project at the existing Holyrood thermal site through multiple regulatory filings with the Public Utilities Board of Newfoundland and Labrador ("PUB").

In February 2025, NL Hydro submitted an early execution application for approximately $30 million to initiate work on the CTs, followed by a full capital application in March estimating the project at $891 million (Class 3 estimate) with a targeted completion date of late-2029. The PUB approved the refiled Early Execution Application in April 2025. In its October 2025 update, NL Hydro reported that the RFP for CT supply closed July 4 and negotiations with General Electric had concluded successfully. A Full Notice to Proceed is required by March 23, 2026, to secure production slots and pricing for the project. The update also confirmed that the estimated completion date has shifted to March 2030 due to procurement delays and extended vendor lead times, and that vendor pricing is significantly higher than the original estimate of $891 million. In December 2025, NL Hydro requested an additional $30 million for advance work and analysis.

This NL Hydro project is an important comparison for the proposed Accelerated Capacity Solution. The NL Hydro project followed a more traditional regulatory path, involving sequential approvals and a competitive bid process, that resulted in a decision to pursue CTs as the preferred solution but at a significantly higher cost per MW and a later in-service date compared to Maritime Electric's Accelerated Capacity Solution. The capital cost of NL Hydro's 150 MW CT project is now estimated to exceed the original estimate of $891 million, with an expected in-service date of March 2030. By comparison, Maritime Electric's Accelerated Capacity Solution includes 100 MW at a total cost of $334 million, deliverable by 2028. On a per-MW basis, the cost reflected in the NL Hydro process is more than 78 per cent higher than the ProEnergy pricing obtained in June 2025, illustrating both the cost-effectiveness and timeliness advantages of the Accelerated Capacity Solution.

New England

Since December 2024, the New England Independent System Operator has not published any material revisions indicating a worsening of long-term capacity shortages, nor has it announced major new dispatchable generation projects.

City of Summerside

Although the City of Summerside was not included in the original Table 16, their capacity planning is relevant.

In June 2025, it was reported that Dunsky Energy and Climate Advisors delivered a new energy strategy report to the City of Summerside recommending that the City "acquire or build 24 MW of wind (14 MW new and 10 MW replacement of expiring West Cape contract), add 10 MW of battery storage, strengthen NB Power interconnection capacity and build 15 MW of new diesel generators using cleaner fuels." In a November 17, 2025, City Council meeting, minutes state that "Summerside Electric has indicated its need for the additional [sic] of an 18.9 MW liquid fuel generation investment to meet reliability and energy security requirements within its service territory." City Council recommended "the investment of up to $400,000 to do the pre-engineering and environmental work required for the generator project."[10]

On a relative basis, the City of Summerside's electric system is approximately one-tenth the size of the Maritime Electric system.[11] Similar to the relative scaling of BESS projects in Nova Scotia and New Brunswick discussed in the Company's response to IR-1, the City's proposed addition of 18.9 MW of dispatchable generation is proportionate to adding approximately 189 MW of dispatchable capacity to the Maritime Electric system. This comparison underscores the scale of Summerside's planned investment relative to its system size and highlights the significant level of capacity being contemplated to meet its reliability needs.

[10] Details on the Summerside Generation project can be found in section 6 of the November 17, meeting minutes which are available on the City of Summerside website - https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_19514871/File/City%20Governance/Council%20Chambers/2025/Monthly%20Council%20Meeting%20Minutes%2011-17.pdf

[11] The City of Summerside's historic peak demand is 36.5 MW versus 359 MW for Maritime Electric.

NERC 2025-2026 Winter Reliability Assessment
The paragraph after Table 16 within the December 2024 Application references the North American Electric Reliability Corporation's ("NERC") 2022-2023 Winter Reliability Assessment report findings.

NERC's report for 2025-2026 will be released in the coming days, at which point the Company will review the findings and provide the Commission with an update to this response.

IR-10 The application indicates that MECL's 190MW of capacity will continue to be required from NBP. Nowhere in the application is there an assessment of the amount of capacity that NBP will have available following the 2026 energy purchase agreement. Please comment on the plans to secure capacity from NBP and status of negotiation of the energy purchase agreement, including capacity requirements.

Response:

Maritime Electric intends to maintain 190 MW of firm capacity from NB Power under a renewed Energy Purchase Agreement ("EPA").[12] This position was included in the December 2024 Application, which noted:

> *"Under the existing EPA, the firm capacity allotment is 180 MW for 2024, 185 MW for 2025, and 190 MW for 2026. For planning purposes, Maritime Electric has assumed that NB Power can continue to provide the 2026 allotment of 190 MW beyond 2026, but no additional firm or short-term capacity would be available."*

This assumption reflects NB Power's indication to continue supplying 190 MW of firm capacity to Maritime Electric, which is referenced in response to IR-2; however, an increase in the allotment beyond the current level is not expected. NB Power has also cautioned that, without adding new capacity resources, it expects to be capacity deficient within five years. NB Power's Resource Adequacy Report, filed as part of its evidence supporting the RIGS project, indicates that export capacity contracts are expected to remain consistent through 2030, signaling NB Power's intention to maintain current capacity export levels.[13] However, NB Power has emphasized that its ability to sustain this commitment is contingent upon the successful execution of its own capacity additions.

Maritime Electric reconfirmed this assumption in its response to IR-2(b) from Synapse on behalf of the Island Regulatory and Appeals Commission filed on November 12, 2025 (Exhibit M-15), stating:

> *"NB Power has indicated that it intends to continue to provide this level (i.e., 190 MW) of firm capacity to Maritime Electric in the future, but that it does not expect to be able to increase this allotment."*

Maritime Electric maintains an active and collaborative dialogue with NBEM regarding future energy and capacity supply. Formal negotiations on the renewed EPA have not yet commenced, as the outcome of the Accelerated Capacity Solution will materially influence both the products to be secured under the EPA and their associated pricing.

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12 The current EPA expires on December 31, 2026.

13 A copy of the NB Power's Resource Adequacy Report can be found in Appendix A to the RIGS Project application - https://filemaker.nbeub.ca/fmi/webd/NBEUB%20ToolKit13 (Matter # EL-002-2025).

IR-11 The August 14, 2025, Supplemental Filing (Exhibit M-12) indicates an in-service date of 2028 for the ProEnergy equipment based on coming to terms with the company in September 2025. What is MECL's plan to address capacity shortfalls that may occur during the winter of 2027. Have any short-term solutions been researched and evaluated? If so, please provide; if not, explain why not.

Response:

Maritime Electric has examined potential options to address short-term capacity shortfalls that will continue until the commissioning of the proposed permanent solution. The Company began by assessing the regional capacity market; however, this review confirmed that there are no viable options to secure additional off-Island capacity for the near term. Neighbouring jurisdictions face similar capacity constraints, leaving no surplus resources available during peak winter conditions. Off-Island capacity will only become available after a neighbouring jurisdiction installs and commissions additional capacity that exceeds their own capacity requirements.

Recognizing this limitation, Maritime Electric evaluated temporary generation options in January 2025. This evaluation considered renting generating assets from multiple suppliers, along with the related site requirements, engineering needs, and operational considerations.[14] Supplier options ranged from smaller units (i.e., as small as 16 MW) to large turbine packages (i.e., up to 29 MW per unit). The estimated first-year costs for approximately 60 MW of rental generation ranged from $33 million to $57 million, depending on supplier and configuration.

It is important to note that this evaluation reflects market conditions as of early 2025. There is no guarantee that the units identified will remain available. Demand for CTs has increased significantly, and many suppliers are shifting away from long-term rentals in favour of outright sales. If rental units are available, costs will likely have escalated.

[14] Even a rental unit would require infrastructure investment in order to connect the unit to the electrical system.

IR-12 Increasing capacity relies on increasing trends for electrification based on population increases and the need for additional housing/building starts. Has MECL completed any sensitivity analysis to model future capacity needs under high, moderate, or low percentage increases to population? If so, please provide that analysis; if not, explain why not.

Response:

Maritime Electric has refined its load forecasting methodology over many years, continuously updating assumptions based on demonstrated predictive accuracy. This ongoing refinement is integrated into the Company's annual load forecast updates, which incorporate observed customer behaviour, evolving weather patterns, technology adoption, and other measurable inputs. The forecasting methodology used today is the same methodology previously reviewed and approved by the Island Regulatory and Appeals Commission.

There are several trends that impact load and Maritime Electric's peak forecast (i.e., capacity requirements), including housing starts, government incentives (e.g., heat pumps and electric vehicles), gross domestic product, demand side management and temperature. Historically, the Company has found that housing starts is a reliable predictor of load growth because new construction directly adds to connected electrical load.

Maritime Electric has found that housing starts typically affect load one to two years after construction begins. Therefore, load increases expected in 2026 and 2027 are largely predetermined by the elevated housing starts already recorded in 2024 and 2025. This timing relationship means upcoming near-term load growth is already "locked in" based on past and current construction activity.

Maritime Electric relies on external sources - specifically the Conference Board of Canada ("CBOC") housing starts forecasts and the PEI Government's Fiscal and Economic Update - to ensure the load forecast is based on objective, industry-recognized data.

As shown in Table IR-12, actual observed housing starts have consistently outpaced the forecasts used in the Company's capacity planning:

- 2024 actual housing starts were 1,694, 40% higher than the CBOC October 2023 forecast of 1,214 used in the December 2024 Application;
- 2025 housing starts as of the third quarter ("Q3YTD") were 1,451, already 17% higher than the full-year CBOC projection of 1,245; and
- The latest forecasts from CBOC (December 2025) and the PEI Government's Fiscal and Economic Updates project continued high levels of construction activity—all higher than the forecasts originally used in the December 2024 Application.

TABLE IR-12 PEI Housing Starts Forecasts					
Year	Actual	CBOC Forecast (Oct. 2023)	CBOC Forecast (Dec. 2025)	PEI 2024-2025 Fiscal and Economic Update Forecast	PEI 2025-2026 Fiscal and Economic Update Forecast
	A	B	C	D	E
2022	1,318	-	-	-	-
2023	1,139	-	-	-	-
2024	1,694	1,214	-	1,600	-
2025	1,451 (Q3YTD)	1,245	1,643	1,800	1,700
2026	-	1,275	1,242	2,000	1,800
2027	-	1,305	1,124	-	-
2028	-	1,335	1,033	-	-
2029	-	-	951	-	-
2030	-	-	880	-	-

Given that actual housing starts continue to exceed prior forecasts, the Company believes its December 2024 capacity requirements forecast is, if anything, conservative.

IR-13 Part of the costs for the proposed addition of two CTs at the Cumberland Street site include a significant expansion to fuel storage facilities. Given the proximity of the bulk tanks that supply all of PEI to the proposed site, are additional tanks required? Would supply agreements provide a better economic benefit and a more environmental solution to supply needs? If so, please provide that analysis; if not, explain why not.

Response:

The final amount of fuel storage required onsite, or the potential to secure supply agreements, to ensure reliable operation of all three CTs will be determined during detailed engineering following approval of the deferral account. Through the engineering design phase, the Company will continue to pursue any cost saving opportunities that are identified.

IR-14 Page 112 of the December 2024 application, note 178, indicates that *"the Company* is *currently studying expansion of the Interconnection. Preliminary results suggest that replacing Cables 1 and 2 with cables similar to Cables 3 and 4, each with a dedicated transmission line, is the preferred option. The study will be completed early in 2025 and will be filed with the Commission upon completion."* What is the status of this study and when will results be available?

Response:

A final draft of the PEI Long-Term Interconnection Study was completed and shared with the PEI Energy Corporation ("PEIEC"), the Government of PEI and the City of Summerside (i.e., all parties that form the PEI/NB Interconnection Committee) on December 4, 2025.

To date no comments have been received from the PEIEC or the Government of PEI. Comments were received from the City of Summerside. Maritime Electric intends to finalize the report in the first quarter of 2026, at which time it will be filed with the Commission.

IR-15 The application focuses only on added capacity needs for MECL customers. Section 5.2.3 of the December application, figure 14, illustrates a 27% increase in energy sales. How is the company looking to address continued increases in energy sales within a tight local energy market?

Response:

Maritime Electric is currently able to secure ample energy supply for customer needs for the vast majority of the year (i.e., 95 per cent of the time) through its existing EPA with NBEM and Power Purchase Agreements for renewable energy generated by the PEIEC. The current EPA will expire on December 31, 2026, and negotiations for the next EPA will begin in the near future.

Additional on-Island dispatchable generating capacity will provide Maritime Electric more flexibility to purchase different energy products from NB Power, including non-firm energy, which would help mitigate energy costs for customers.

While the regional electricity market is very tight on capacity, it generally has energy available for sale throughout most of the year. For example, NB Power entered into a long-term agreement with Hydro-Québec (“Quebec”) several years ago to import a total of 47 terawatt-hours (i.e., 47,000,000 megawatt-hours) of electricity between 2020 and 2040.[15] This energy is not capacity-backed - meaning it is not guaranteed during peak periods - because Québec does not have additional firm capacity during peak periods. However, for the vast majority of the year, Québec has energy available to supply NB Power. Similarly, the Maritimes region typically has adequate resources to supply energy for most of the year, with shortages occurring only during cold weather or significant generation or transmission outages.

Additionally, several renewable energy projects are currently in the interconnection queue which have the potential to contribute to PEI’s future energy requirements. These proposed projects include approximately 166 MW of new wind generation and 164 MW of photovoltaic solar generation, with anticipated in-service dates ranging from 2026 to 2029. While these projects will not eliminate the need for firm dispatchable capacity, some could form part of the overall energy mix to serve customers.

The December 2024 Application and Supplemental Filing for the Accelerated Capacity Solution are meant to address the remaining five per cent of the time, when loads across the region are high and neighbouring utilities do not have excess energy for sale.

15 Details of the Agreement between Hydro-Quebec and NB Power can be found on NB Power’s website - https://www.nbpower.com/en/about-us/news-media-centre/news/2020/hydro-quebec-and-nb-power-sign-agreements-on-electricity-purchases-and-expertise-sharing/

IR-16 Increasing the on-Island capacity available for MECL through acquiring two 50MW CT units is the only option presented. There are many that believe that a true comprehensive grid modernization strategy is required. What is MECL doing to plan for a modern grid?

Response:

Maritime Electric respectfully disagrees with any assertion that the Company only considered one option. In fact, Maritime Electric filed a comprehensive Capacity Resource Study with the Commission on February 10, 2023, and forwarded a copy to PEIEC.[16] This study examined a broad range of potential capacity resources, and their suitability to Maritime Electric's needs.

The scope of the Capacity Resource Study included:

- Evaluation of 16 potential technologies based on screening criteria;
- Screening criteria included whether the potential technology is a proven technology (i.e., does the technology have sufficient energy industry deployment to ensure viability and reliability) and whether there is sufficient and economical supply of the required fuel (or natural resource) to support electricity generation; and
- From this screening process, 8 technologies advanced to a second-stage evaluation for more detailed consideration.

The Capacity Resource Study resulted in a recommendation to proceed with a portfolio of three technologies, including a combustion turbine. When the Accelerated Capacity Solution became available, via the NB Power RIGS project, Maritime Electric transitioned to present that option as it was the most economically viable solution which could be commissioned by 2028 - two years earlier than alternate solutions. This process demonstrates that Maritime Electric did not restrict its analysis to a single option but instead evaluated a full range of alternatives.

Grid Modernization Initiatives
Grid modernization extends well beyond just generation planning. Maritime Electric has undertaken significant steps to modernize its electrical grid, which is summarized as follows:

1. **Wind Integration:** Maritime Electric began integrating wind resources in the early 2000s, achieving approximately 25 per cent of its overall energy supply from PEI-based renewables by the mid-2010s, after which load growth diminished this percentage. In 2026 Maritime Electric is forecast to exceed 25 per cent of its supply from PEI-based renewable generation once again, following the recent commissioning of the Eastern Kings Phase 2 wind farm.

   This percentage of PEI-based renewable generation excludes on-Island wind that is sold to off-Island markets, via Maritime Electric's system.[17] Including this additional generation would increase the expected percentage to greater than 40 per cent for 2026. For comparison, the province with the next highest percentage of renewable generation is

[16] An addendum to the Capacity Resource Study was filed with the Commission on July 21, 2023, following the significant loads experienced on PEI during the February 2023 polar vortex event.

[17] Although this wind energy is sold off-Island, it is physically integrated into the Maritime Electric system. As a result, the technical requirements associated with accommodating high levels of renewable generation (i.e., renewable backstopping, voltage support, and contingency response) must still be provided by Maritime Electric.

Nova Scotia at approximately 13 per cent.

2. **Behind-the-Meter Solar:** Currently, more than 51 MW of behind-the-meter solar is installed on Maritime Electric's system - a proportion that is significantly higher relative to the size of the system compared to any other electrical utility in Canada.[18]

3. **Advanced Metering Infrastructure ("AMI"):** This ongoing project to install smart meters and an associated communication network will provide real-time visibility into system voltages and other critical data, enabling more effective system operation. The AMI communication network will also support future grid modernization initiatives by enabling communication with downstream devices.

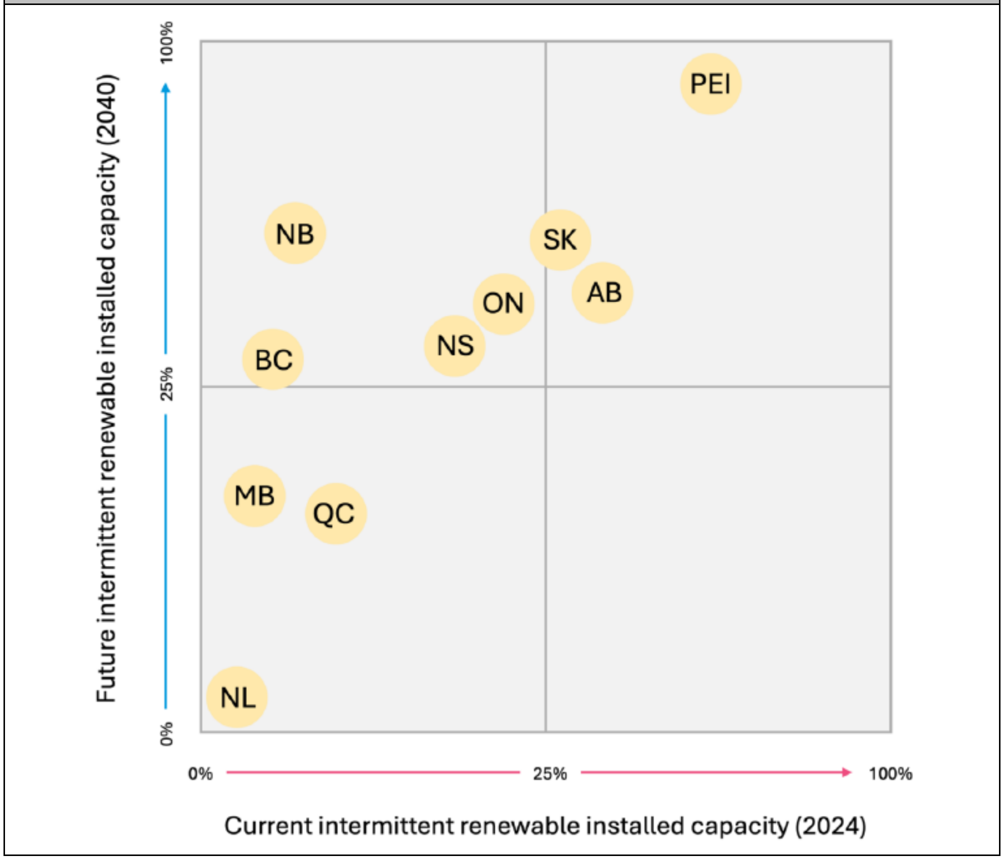
4. **Charlottetown Grid Modernization Project:** Maritime Electric recently secured 50 per cent federal funding for this pilot project, which will deploy automated switching, voltage regulation, and communication systems on the 13.8 kilovolt distribution network serving approximately 8,000 customers in Charlottetown. The project will enhance grid visibility, enable remote control of devices, improve outage restoration, and support the integration of distributed energy resources such as rooftop solar. The Company plans to use the final design and lessons learned from this initiative to inform future projects aimed at increasing grid modernization throughout the rest of the electrical system.

5. **Fibre Optic Expansion:** Maritime Electric has continually expanded its fibre-optic network to substations throughout PEI, increasing telemetry capacity and strengthening system visibility, which in turn supports the implementation of broader grid-modernization initiatives.

To support Maritime Electric's claim that it has incorporated higher amounts of renewable generation into its system compared to any other province in Canada, the Company has attached an Intertie Study completed by Deloitte LLP ("Deloitte"), which was commissioned by Electricity Canada, as IR-16 - Appendix 2 to these responses. On pages 13 and 14 of that study, Deloitte presents the role of intermittent resources (i.e., renewable resources) currently and in the future for each province in Figure 4, which is provided below for ease of reference. Provinces in the bottom-left quadrant of Figure 4 are low adopters of intermittent resources and continue to depend on traditional resources. While provinces in the top-right quadrant are the high adopters of intermittent resources who have significant intermittent capacity deployed today and aim to grow this out to 2040. PEI holds the highest place in the top-right quadrant, above all other provinces in Canada.

[18] Behind-the-meter solar differs from utility-scale solar because it lacks utility-grade protection devices and is connected closer to customers, creating unique operational challenges that must be addressed by the utility.

Figure IR-16
Copy of Figure 4 taken from the Deloitte Intertie Study included as Appendix 2



IR-17 As per Exhibit M-12 Appendix A, Sergent & Lundy's August 13, 2025, letter to MECL, noted that PEI's peak load is expected to reach approximately 408 MW in 2027. Given PEI's current interconnection limit of 300MW and 104MW of dispatchable on-Island generation, PEI is at risk of being unable to meet peak load times without curtailments. Please explain how usage has been trending since the August 2025 letter, and whether the system has approached peak capacity in recent months.

Response:

Peak load trends continue to increase. Maritime Electric discussed peak load trends in a letter to IRAC dated April 23, 2025 (Exhibit M-3). Table IR-17(i) below is an update to Table 1 from that letter. Note that the table includes Maritime Electric load only – City of Summerside load is excluded.

Table IR-17(i) shows that moderately cold temperatures are now resulting in significantly elevated peaks.

TABLE IR-17(i) (Update to Exhibit M-3 Table 1) Maritime Electric System Peak Loads			
Year	Temperature at Peak[a] (°C)	Maritime Electric System Peak (MW)	Space Heating Peak Coefficient (MW/°C)
2016	-15.9	237	2.1
2017	-14.8	250	2.3
2018	-17.1	250	2.5
2019	-13.1	245	2.6
2020	-11.9	260	2.9
2021	-13.3	246	3.1
2022	-18.5	293	3.7
2023	-23.8[b]	359	4.1
2024	-11.0	310	4.5
2025	-14.9	346	5.1
2026 YTD	-17.9	362[c]	6.3[d]
10-Year Average[e]	-15.4		

a. Source: Environment Canada (Charlottetown Airport).
b. 2023 peak occurred during a polar vortex weather event. The temperature shown is the average temperature for 24 hours prior to the peak.
c. The 2026 year-to-date ("YTD") system peak occurred on January 25. The peak load of 362 MW shown is from the Company's Energy Purchase System and is subject to change following more precise meter readings obtained at the end of the month.
d. Preliminary results based on December 2025 and YTD January 2026 peak data.

On January 25, 2026, Maritime Electric's YTD system peak of 362 MW occurred between the hours of 5:00 and 6:00 p.m. when the ambient temperature was -17.9°C. The resulting space heating peak coefficient of 6.3 MW/°C, which represents the MW increase in Maritime Electric's system peak load for every 1°C drop in temperature, demonstrates the seriousness of the capacity challenge faced by PEI. A temperature of -20°C at peak is now estimated to result in a Maritime Electric system peak of 375 MW (or a total of approximately 417 MW for PEI).[19]

[19] Based on 2026 data, the peak would be 375 MW: -17.9°C minus -20.0°C = 2.1°C; 2.1°C x 6.3 MW/°C = 13 MW; 13 MW + 362 MW = 375 MW. Maritime Electric's system peak is approximately 90% of the PEI total.

As Maritime Electric's system peak continues to increase, delaying the installation of additional on-Island dispatchable generating presents significant security of supply risks. Every winter without additional on-Island dispatchable generating increases the probability and the consequences (i.e., magnitude and duration) of capacity shortages (i.e., rotating outages) for PEI and its residents.

The PEI-NB interconnection transmission capacity limit of 300 MW can be misleading as it does not represent the amount of firm capacity actually available to PEI.

As explained in Maritime Electric's December 2024 Application (Exhibit M-1), only 219 MW of firm generating capacity is currently available from New Brunswick (i.e., 190 MW from NB Power plus 29 MW from Point Lepreau). Firm capacity is the amount of capacity that is contractually reserved for Maritime Electric, and imports from New Brunswick that exceed this amount are not guaranteed and can be curtailed at any moment. Given capacity shortages currently being experienced in New Brunswick, the probability of curtailments will become a certainty during high-load and low-wind periods (i.e., high demand and low supply).

Considering the current firm capacity available to Maritime Electric, the loads experienced on January 25, 2026 exceeded the Company's firm, dispatchable resources by approximately 54 MW.[20] The system was able to meet this peak only because sufficient wind generation happened to be available at that time, highlighting the increasing reliance on intermittent resources to bridge an increasing capacity gap.

20 362 MW – 219 MW – 89 MW (i.e., Maritime Electric's on-Island dispatchable generating capacity) = 54 MW

IR-18 With regards to the proposed deferral outlined in Exhibit M-12, please provide additional details, including the proposed definitions of the account, eligible cost categories, recording methodology, recovery, and timeline for reporting to the Island Regulatory and Appeals Commission.

Response:

In responses to Commission Staff interrogatories filed on January 15, 2025, Maritime Electric provided detailed information on the proposed deferral account, including the nature of risks to be transferred, the breakdown of costs, accounting treatment, and rationale for prudency. These responses (specifically responses to IR-10, IR-11, and IR-12) explain that the deferral account is intended to manage upfront costs required to maintain alignment with NB Power's schedule, mitigate reliability risks, and preserve the opportunity to secure the ProEnergy solution. They also outline the proposed structure for recording balances, carrying costs, and the Company's position that approval is necessary to avoid significant delays and certain cost escalation.

IR-6 – APPENDIX 1

Letter to Response to Second Set of Interrogatories from Synapse Energy Economics on behalf of Island Regulatory and Appeals Commission dated November 12, 2025

All our energy.
All the time.

MARITIME ELECTRIC
A FORTIS COMPANY

November 12, 2025

RECEIVED
NOV 1 2 2025
The Island Regulatory and Appeals Commission

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

Dear Ms. Bradley:

Supplemental Capital Budget Request
On-Island for Security of Supply Project – Docket UE20742
Response to Second Set of Interrogatories from Synapse Energy Economics
On behalf of Island Regulatory and Appeals Commission

Please find attached Maritime Electric Company, Limited's ("Maritime Electric" or the "Company") responses to the second set of interrogatories from Synapse Energy Economics ("Synapse") on behalf of the Island Regulatory and Appeals Commission (the "Commission") with respect to the On-Island Capacity for Security of Supply Project received on October 29, 2025.

An electronic copy of this submission will be forwarded shortly.

A number of the interrogatories from Synapse are directly or indirectly related to the use of a Battery Energy Storage System ("BESS"). This letter intends to provide the Commission with additional information about the possible use cases of BESSs by Maritime Electric for consideration in its decision.

There are three primary use cases of BESSs in the electric utility industry: (1) energy arbitrage, (2) ancillary services and (3) capacity resource.[1] The three BESS use cases can provide value for a utility and its customers depending on a power system's specific needs and circumstances. These use cases and their implications for Maritime Electric are described in detail in this letter.

In Maritime Electric's case, the value of energy arbitrage is negligible, ancillary service benefits are limited, and the use of a BESS as a capacity resource does not eliminate the need for additional dispatchable generation. Maritime Electric's proposed Accelerated On-Island Capacity Development Solution ("Accelerated Capacity Solution") for 100 MW of combustion turbines ("CT"), as filed in the August 2025 Supplemental Filing ("Supplemental Filing"), is essential to address the Company's capacity deficit and to maintain security of supply for customers at the lowest reasonable cost.

.../2

1 Only one of the use cases can be utilized at any given time. For example, a utility may use a BESS as a capacity resource during the winter months and for ancillary services for non-winter months.

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Use Case 1: Energy Arbitrage

Utilizing a BESS for energy arbitrage refers to the practice of charging it when marginal energy costs are low (e.g., during off-peak periods) and discharging it when marginal energy costs are high (e.g., during on-peak periods).[2] Energy arbitrage allows the user to store produced or purchased energy when costs are low and to use it at a later time when energy costs are higher. Economic value is derived when the price spread between low- and high-cost energy is significant enough to compensate for the BESS's round-trip efficiency (typically 85 per cent).[3] Energy arbitrage is more common in jurisdictions with significant variability in energy prices throughout the day due to variability in demand (e.g., nighttime versus daytime load) or supply (e.g., excess solar energy during the day).

Maritime Electric's energy supply situation is unique and currently not suited for energy arbitrage. The Company does not operate baseload generation and, today, 100 per cent of wind energy purchased through power purchase agreements is used instantaneously by customers without the need for curtailments or off-Island exports. As a result, the Company's marginal energy source (i.e., the source of the next unit of energy) is primarily energy purchased from New Brunswick Power ("NB Power").[4,5] Maritime Electric's current Energy Purchase Agreement ("EPA") with NB Power includes fixed energy pricing (i.e., the price is the same for all hours of the year);[6] therefore, Maritime Electric currently has no "low" and "high" marginal energy cost periods that are required for energy arbitrage (i.e., the marginal energy unit price is always the same).

Although Maritime Electric's current EPA with NB Power includes fixed energy pricing, it is evident that NB Power's marginal energy costs are variable. NB Power is currently interconnected with ISO New England ("ISO-NE") which publishes hourly locational marginal pricing ("LMP") for various interconnections including the NB External Node.[7] This ISO-NE LMP represents NB Power's opportunity costs (if they sold electricity to ISO-NE instead of Maritime Electric) and is a reasonable proxy of NB Power's hourly marginal electricity prices for evaluation purposes.

An evaluation of hourly ISO-NE LMP for the NB External Node in 2024 reveals that the average off-peak electricity price was $46.41/MWh and the average on-peak price was $57.41/MWh.[8] This information is useful in evaluating the potential economic value of energy arbitrage in the region. A 50 MW 4-hour BESS has a total energy storage capacity of 200 MWh. A round-trip efficiency of 85 per cent results in 216 MWh required to fully charge the BESS and 185 MWh available for discharge.[9] Charging the BESS with 216 MWh during off-peak periods at $46.41/MWh has a cost of $10,025. Discharging the energy stored provides 185 MWh to the grid during on-peak periods when energy prices are $57.41/MWh, resulting in $10,621 of avoided costs. Using the BESS for energy arbitrage, in this scenario, would provide a value of approximately $596 per cycle (on

2 Marginal energy costs refer to the price to produce the next unit of electricity demand and is analogous to avoided energy costs.

3 Round-trip efficiency is the ratio of the BESS's total useful energy discharged relative to the total energy required to charge it. A round-trip efficiency of 85 per cent indicates total losses of 15 per cent.

4 Maritime Electric purchases energy and capacity from New Brunswick Energy Marketing Corporation, but "NB Power" is used for simplicity.

5 The only exception is during periods when energy from NB Power is curtailed and Maritime Electric's CTs are operating.

6 The current EPA with NB Power expires at the end of 2026.

7 Location ID number for the NB External Node is 4010; location name is ".ISALBRYNB345 1."

8 Converted to CAD using a USD to CAD exchange rate of 1.37 in 2024. Based on ISO-NE published on- and off-peak periods.

9 200 MWh / 92.5% = 216 MWh. 200 MWh x 92.5% = 185 MWh.

average) or $152,650 for the 2024 year (assuming one full charge/discharge cycle per day).[10] This annual value is negligible relative to the capital cost of installing a 50 MW 4-hour BESS, which is estimated at $135.5 million.[11]

Maritime Electric's energy supply circumstances and negligible potential economic value of energy arbitrage in the region do not currently support using a BESS for energy arbitrage.

Use Case 2: Ancillary Services

Utilizing a BESS for ancillary services refers to the practice of using it to support grid reliability and stability by providing services such as frequency regulation, voltage support, spinning reserve and load following. These ancillary services are described in detail in Section 6.1 of the December 2024 Application.

Maritime Electric's current ancillary services obligations that could be supported by a BESS include 4.7 MW of load following and 7.8 MW of spinning reserve (12.5 MW total).[12] Maritime Electric's December 2024 Application proposed using the 10 MW 4-hour BESS to meet 10 MW of its ancillary service requirements during periods of the year that the BESS is not required as a capacity resource (see use case 3). This use of the BESS improves the business case for it; however, a BESS larger than 12.5 MW has diminishing value because 12.5 MW is the upper limit of the BESS's use to meet the Company's ancillary service obligations.

Maritime Electric's December 2024 Application, which proposed a 10 MW 4-hour BESS, takes advantage of the BESS's full 10 MW capacity to meet the Company's ancillary service obligations. BESSs that are larger than 12.5 MW provide no incremental ancillary service benefit.

Use Case 3: Capacity Resource

Utilizing a BESS as a capacity resource refers to the practice of deploying it to supply power during peak periods. Maritime Electric's December 2024 Application proposed using the 10 MW 4-hour BESS as a 10 MW capacity resource during the winter period from December to February to help meet the Company's capacity requirement. Section 8.3 of the December 2024 Application explained why Maritime Electric did not propose additional BESS capacity.

The challenge with using a BESS as a capacity resource is that it is fundamentally different than traditional dispatchable generation resources due to its limited supply duration. As such, electric utilities and system operators must study the use of BESSs as capacity resources to determine their effective load carrying capability ("ELCC"). The ELCC is the portion of the nameplate capacity that can be reliably counted as a capacity resource towards meeting the capacity requirement. BESS ELCC studies are complex because they are dependent on the BESS's ability to discharge stored energy during peak periods and whether there are sufficient surplus generation resources (such as wind, solar, dispatchable generation and off-Island energy) to charge the BESS during off-peak periods.

Figure 1 shows a visual representation of Maritime Electric's energy resources to illustrate that the ability of a BESS to reliably contribute as a capacity resource depends on the foundation

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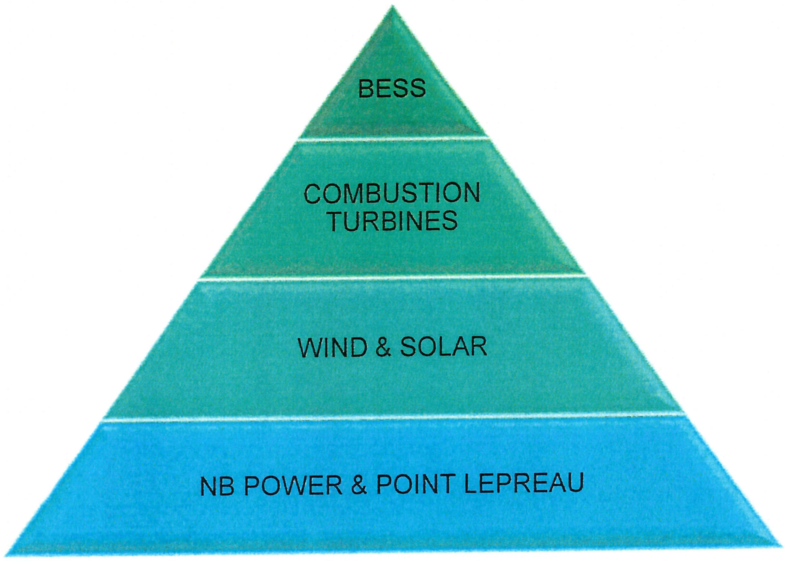
10 $10,621 – 10,025 = $596/cycle. $596/cycle x 256 days with on-peak periods = $152,650/year.

11 Capital cost estimate based on Sargent and Lundy December 2022 cost estimate.

12 Maritime Electric also has a 1.7 MW automatic generation control obligation, but there is currently uncertainty about whether this ancillary service can be supported by a BESS.

provided by other generation resources. Below BESS in the pyramid, in order of dependency, are Maritime Electric's energy resources (including NB Power, Point Lepreau, wind, solar and CTs) that can supply energy needed to charge the BESS before peak demand periods. Maritime Electric is forecasting such a significant capacity resource deficit (156 MW by 2033) that it will not have sufficient generation resources to provide a strong foundation for a BESS. Without a strong foundation, a BESS cannot be charged effectively, and its ability to act as a reliable capacity resource is limited.

FIGURE 1
Pyramid of Maritime Electric's Energy Resources



Some other jurisdictions have begun studying BESS ELCC. Recently, Nova Scotia Power Incorporated ("NSPI") published BESS ELCC values used in its Integrated Resource Plan ("IRP") studies. In August 2023, Synapse provided comments to the Nova Scotia Energy Board ("NSEB," formerly the Nova Scotia Utility and Review Board) regarding NSPI's calculation of BESS ELCC in the 2023 Evergreen IRP.[13] In its comments, Synapse stated the following:

> *As noted, the battery energy storage ELCC profile used in this IRP update is a critical input value to the modeling that needs to be carefully re-examined in the next IRP or IRP update. The re-examination needs to be conducted in conjunction with an updated "portfolio ELCC" analysis that better considers the interactive effect of all four clean resources (wind, solar PV, battery energy storage, and demand response or peak load mitigation during winter peak periods). The current input assumptions used for ELCC for the portfolio of resources, while reflecting some level of diversity benefit, do not fully capture this critically important dynamic.*

In response to the Synapse comments, NSPI acknowledged the recommendation to expand the ELCC study and agreed to investigate it prior to completing the next IRP.[14] However, NSPI stated that:

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13 NSEB Matter M11307 Exhibit N-3 page 6.
14 NSEB Matter M11301 Exhibit N-5 page 7-8.

[...]there is an average requirement of approximately 600MW of new fast acting generation capacity by 2032 in No Atlantic Loop Evergreen IRP scenarios. The Company's 2023 Load Forecast Report also shows accelerated firm peak growth relative to the 2022 Load Forecast Report. Accordingly, although there is potential value in the diversity benefit of added solar and storage, further study is not necessary prior to proceeding with the first addition of 300MW of new fast acting generation with an in-service target of 2027 identified in the 2030 Resource Development Plan.

Due to timeline constraints, the NSEB accepted the results of the 2023 IRP Update, as filed, but directed NSPI to consider Synapse's comments in the next iteration of its IRP.

Maritime Electric acknowledges that more than the 10 MW of BESS capacity proposed in its December 2024 Application may be technically feasible as a reliable capacity resource, but this would require further study to evaluate the ELCC of BESS under various diversified energy portfolios. While the Company is prepared to study the potential for additional BESS capacity beyond what was proposed in the December 2024 Application, such study should not delay proceeding with the first 100 MW of CTs proposed in the Supplemental Filing. The December 2024 Application identified the need for 150 MW of additional capacity and the Company expects to continue to purchase 190 MW of capacity from NB Power. If a larger BESS is deemed technically and financially viable, it can serve to meet the remaining 50 MW of the December 2024 Application or offset capacity purchases from NB Power.

Capacity Cost Comparison

In addition to the technical issues already discussed, using a BESS larger than 10 MW for capacity is not the least cost solution. Table 1 shows a cost comparison of the Accelerated Capacity Solution with high, medium and low BESS ELCC scenarios for a 50 MW 4-hour BESS. The results show that, even if a 50 MW 4-hour BESS has an ELCC of 100 per cent (i.e., the full nameplate capacity can be counted), 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).[15]

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**

a. Calculated using Maritime Electric's weighted cost of capital.

[15] 24,366 / 6,863 = 3.55.

Conclusion

There are three primary use cases for BESSs in the electric utility industry, of which only one can be utilized at a given time. Maritime Electric's energy supply situation does not currently support using a BESS for energy arbitrage. The Company has 12.5 MW of ancillary service obligations that can be supported by a BESS, but BESSs that are larger than 12.5 MW provide no incremental ancillary service benefit. There are opportunities to study the ELCC of BESSs for use as a larger share of capacity resources in Maritime Electric's system and the Company is prepared to do so, but this does not eliminate the critical and immediate need for the 100 MW of CTs proposed in the Supplemental Filing.

Under the provisions of the PEI *Electric Power Act*, Maritime Electric is responsible for providing a reliable and secure supply of electricity to customers and making prudent investments to ensure service is delivered at the lowest reasonable cost. Under current system conditions, a BESS by itself is not a reliable capacity option, nor is it the least cost solution to the very serious capacity deficit facing the Company. For this reason, the proposed Accelerated Capacity Solution, which is critical to maintain security of supply for customers at least cost, must proceed immediately.

Should you require clarification or additional information concerning the content of this letter or the attached interrogatories responses, please let me know.

Yours truly,

MARITIME ELECTRIC

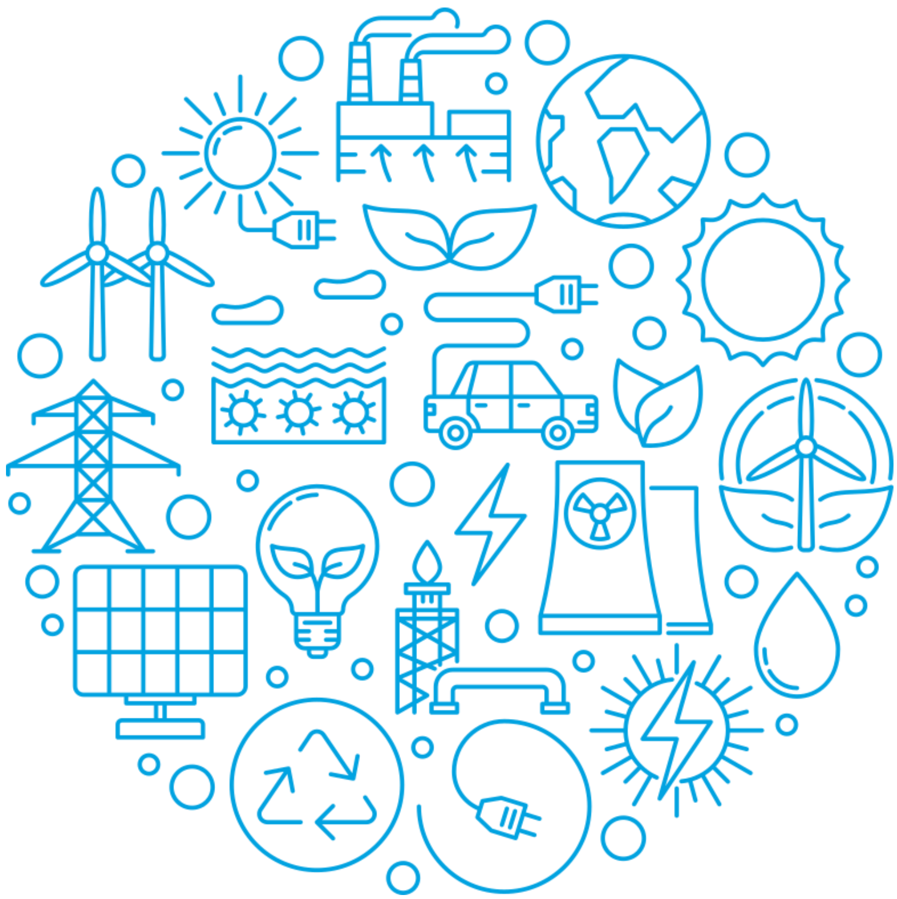
Michelle Francis
Vice-President, Finance & Chief Financial Officer

MF50
Enclosure

IR-16 – APPENDIX 2

Deloitte
Intertie Study
December 2025

Deloitte.



December 2025

Intertie Study

Commissioned by

Electricity Canada
Our energy future

Table of contents

Executive summary

Canada's electricity system has historically delivered reliable, affordable, and low-emission electricity, with each province developing distinct and different resources, market, and regulatory frameworks to meet local needs. As demand for electricity is expected to increase, driven by economic growth, electrification of transport and industry, and emerging sectors, the necessity to expand the electric system and the value of optimizing the Canadian grid through enhanced interprovincial transmission has never been greater or more timely. Deloitte, commissioned by Electricity Canada, conducted a thorough analysis of Canada's intertie network, examining both current usage and future supply-demand scenarios to assess how strategic transmission investments might support a resilient, affordable, and sustainable electricity system.

The analysis illustrated that Canada's interprovincial interties already play a vital role in supporting reliability and market outcomes, with most connections operating at high utilization rates during peak periods. However, capacity is unevenly distributed, province-to-province from coast-to-coast, potentially resulting in regional constraints and limited flexibility to transfer electricity where it is most needed limiting Canada's ambition of a more regionally optimized system. Looking ahead to 2040, supply-demand forecasts indicate that some provinces are likely to maintain surplus capacity, while others may face deficits under stress scenarios. These findings highlight the strategic value of optimizing interprovincial transmission to facilitate resource sharing, balance supply and demand, and support provinces with growing intermittent renewable generation, such as wind and solar. Enhanced interconnections would allow provinces with firm hydroelectric and nuclear resources to provide backup and reliability to those with variable supply and generation from intermittent renewables, improving overall system resilience.

Regional case studies further illustrate the benefits of coordinated transmission planning. For example, the Ontario–Quebec intertie demonstrates how complementary supply and seasonal demand patterns can be leveraged through strategic agreements, while Atlantic Canada's reliance on eastward flows underscores the importance of expanding interties to meet future reliability and clean energy goals. Opportunities identified by the study include strengthening interties in Western Canada to support resource optimization, enabling Manitoba to mitigate future supply constraints through increased imports, expanding transmission links from Quebec and Newfoundland & Labrador to Atlantic Canada, and continuing to optimize the Ontario–Quebec corridor.

Unlocking the benefits of interprovincial transmission in Canada requires coordinated action across economic, governance, regulatory, and financing dimensions, with governments and utilities working together to define market opportunities, harmonize regulations, clarify federal-provincial roles, and establish equitable cost-sharing frameworks. Proactive, regionally coordinated planning and investment, supported by policy incentives and strong federal leadership, will be important for optimizing transmission to meet future electricity demand reliably and affordably, while preventing fragmented and inefficient infrastructure development. Electricity Canada is well positioned to lead stakeholder alignment and advance practical and timely recommendations, helping to build a more efficient, integrated, and resilient electricity system that supports Canada's long-term economic and climate objectives.

Background and objective

Background

Canada's electricity system has historically delivered reliable, affordable service with one of the world's lowest greenhouse gas emission intensities. In Canada's province-by-province system, each province has developed unique supply side resources, regulatory structures and market instruments to meet to meet local demand, effectively managing generation, transmission, and distribution. Despite economic and population growth, electricity demand has remained stable over the past two decades due to energy conservation technologies and shifting customer loads. Meanwhile, non-emitting and intermittent resources are increasingly cost-effective, while costs for traditional generation (i.e., hydroelectric, nuclear, and fossil fuels) have risen significantly relative to the 20th century, when a large majority of the current supply-side resources were built.

Looking ahead, electricity demand is expected to grow significantly, driven by economic growth, new sources of demand like AI data centers, and the electrification of transportation, heating, and industrial processes. At the same time, aging bulk and distribution level infrastructure will require replacement or refurbishment, and Canadian utilities will need to compete globally for a constrained supply of system components and domestically for skilled labor, both of which will drive up costs. These changes will challenge utilities to maintain reliability and affordability, while supporting economic and sustainability goals.

Canada can reliably and affordably expand its electricity system to support future growth and sustainability. Existing system efficiencies, diverse resources, experience in nuclear, hydroelectric, and wind development, active participation of Indigenous communities, and advancements in grid modernization all strengthen Canada's position. Provinces share the ambition to expand their electricity systems to enable economic growth, and the federal government acknowledges its role in supporting provincial efforts as part of a broader strategy to strengthen national competitiveness. Achieving these goals will require renewed focus on reliability, affordability, economic enablement, and sustainability.

Study objective and opportunities for interprovincial transmission

Electricity Canada has engaged Deloitte to assess the role of enhanced provincially interconnected transmission infrastructure in Canada's future energy system.

Enhanced interprovincial transmission presents an opportunity to meet future electricity demand efficiently and affordably. By elevating transmission to a central pillar of national energy strategy and increasing integrated regional planning across provinces, Canada can unlock opportunities for **meeting future demand while minimizing costs**, **enhancing system resilience**, and **advancing economic and nation-building goals.**

Meeting future demand while minimizing costs:
Rising demand driven by needs of a growing economy and climate goals require substantial investment. Historically, provincial-focused planning, with transmission as secondary to generation, has led to national inefficiencies and missed opportunities, including overbuilding generating capacity and underutilizing intermittent renewable resources (e.g., solar, wind). A more integrated regional or national approach would promote system optimization and position transmission as a strategic enabler, reducing investment costs, supporting resource sharing, and improving reliability and affordability for ratepayers and taxpayers.

Enhancing system resiliency:
Each province has unique supply strengths and challenges. As the electricity system incorporates an expected increased share of more costly capacity resources and diverse and intermittent energy resources, coordinated optimization can lead to a stronger, more adaptable system that delivers value. Some provinces can develop certain generation types more cost-effectively due to geography, resources, and regulation. A

coordinated approach to interprovincial transmission, similar to shared ambitions in nuclear technology, can enhance reliability and maximize the use of low-cost, intermittent renewables. Improved connectivity allows regions to leverage their respective strengths, balance supply and demand, support each other during outages, and manage supply chain and labor constraints, increasing reliability and flexibility.

Advancing economic and nation-building goals:
Strengthening interprovincial transmission is a nation-building opportunity and an enabler of trade, economic integration, consumer affordability, and strategic investment across Canada. While interties have historically focused on reliability and prioritized US exports due to market size and pricing mechanisms, optimizing the Canadian electricity system now aligns with provincial and federal priorities. A modernized, interconnected grid not only enhances national economic development and resilience, promoting nation-wide benefits. Importantly, the value of expanded transmission extends beyond the ratepayer by enabling new industrial activity, such as mining of critical minerals and data centres, which drives job creation, increases tax revenues, and contributes to economic prosperity for Canadians.

Given anticipated shifts in demand and supply, Canada should prioritize regionally coordinated transmission planning to deliver a secure, cost-effective, and future-ready electricity system. Achieving this requires a more formal, integrated planning process, with transmission considered proactively alongside bulk generation, distributed energy resources, non-wires alternatives, and demand-side measures, allowing all options to compete and contribute to a resilient electricity system.

Approach and methodology

This study examined the provincial intertie landscape, focusing on intertie capacity and utilization. Deloitte assessed provincial forecasts to identify supply-side resource requirements and the role of transmission as a resource. The study explored the premise that, to build the new capital-intensive system of the future required to deliver on and maximize economic growth opportunities, the sector must account for the unique characteristics of existing provincial systems, their potential for expansion, and the importance of leveraging all available resources, including generation, distribution, and, notably, interprovincial transmission. The study followed a three-phase approach designed to deliver data-driven insights based on data collection and validation, followed by an analysis of the current state of the interprovincial intertie system and a future state assessment of the provinces' energy future. These insights informed where enhanced interprovincial transmission could deliver value, guiding recommendations for system optimization and identifying priority areas for future planning and investment.

Figure 1 – High level view of approach that was used for the study.

Phase 1 *Data collection*	**Phase 2** *Current state assessment*	**Phase 3** *Future state assessment*
Collect and validate all intertie and provincial energy system data	Understand how interties are currently being used today	Determine how intertie usage might evolve in the future and their role in provincial energy system

Phase 1: Data collection and validation

Objective: Collect and validate all intertie and provincial energy system data

Electricity Canada and Deloitte worked jointly to collect the relevant information required for the analysis by leveraging member data and publicly available sources[1] [1]. Electricity Canada provided historical and forecasted information on energy consumption, peak demand, capacity supply, and energy supply for each province, along with contextual data such as generation retirements, planned assets, reliability metrics, stress events, and relevant policy considerations. Deloitte collected intertie-specific data, including capacity, total transfer capability, and peak and average intertie flows. Additionally, contextual information was collected such as operational constraints, planned upgrades, and curtailment or outage history. To ensure completeness and accuracy, Electricity Canada leveraged its member network to validate the dataset and supplement gaps. All sources were documented to maintain transparency.

Phase 2: Current state analysis

Objective: Understand how interties are currently being used today

Using the validated intertie data, Deloitte assessed the current state of the interprovincial transmission intertie system. This involved visualizing a map view of the interties across the provinces along with key data for each intertie. Two key data points were leveraged to explore the current state of each intertie:

1. **Total transfer capability (TTC)**
   The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions [3]. TTC is defined between provinces for east-west interties and between a province and a transmission operator/owner (e.g., RTO, ISO, etc.) for north-south interties.

[1] Where utility data was unavailable, supplementary information was primarily sourced from the Canadian Energy Regulator [2]

2. **Peak demand utilization (%)**
   This metric provides an approximation of how the intertie is being used during the highest annual demand relative to the TTC. This is achieved by dividing the *annual peak demand flow (MW)* by the *Intertie TTC (MW).* It does not consider other factors including Transmission Reliability Margin (TRM), Available Transfer Capability (ATC), or relative market economics between jurisdictions that may impact utilization[2].

Both data points represent the average across 2023, 2024, and 2025. Where data for all three years was not available, the average was calculated using the years for which data was available. Data was sourced using publicly available information or directly from Electricity Canada members [1]. This examination was done with an understanding that the common use cases for interties include reliability during grid emergencies, additional capacity, and market arbitrage.

With this visualization, data, and frame of reference for intertie usage in hand, Deloitte selected three interties to further research and support in demonstrating how the current intertie system is utilized today.

Phase 3: Future state analysis

Objective: Determine how intertie usage might evolve in the future and how interties should be considered when planning provincial energy systems

Deloitte identified illustrative future opportunities for provincially interconnected transmission infrastructure by conducting two sets of analysis based on the forecasted demand and supply to 2040 for each province.

1. **Supply – Demand Ratio Analysis**
   This analysis compares each province's projected 2040 effective capacity and peak demand (within-province demand), expressed as a normalized ratio, where (+/-) values indicate potential surplus or deficit. To assess system adequacy under varying conditions, two scenarios are modeled: (1) the Baseline scenario, which uses provincial forecasts for demand growth and planned capacity additions; and (2) the Stretched scenario, which applies an illustrative incremental15% increase to each province's annual total demand forecast and a 25% reduction to annual incremental growth in generation capacity to reflect potential stressors such as extreme weather events, policy shifts that increase demand and permitting or supply-chain constraints which slow build limits and growth in capacity infrastructure readiness. Demand data came from Electricity Canada member-validated data [1], with gaps filled using linear forecasting. Capacity data was sourced from the CER [2] or directly from members [1], considering only domestic generation except for Quebec's Churchill Falls agreement [5]. For both the Baseline and Stretched scenarios, capacity was adjusted to account for the effective load carrying capability (ELCC) of different generation resources (i.e., the ability for a generation source to reliably meet peak demand). It is assumed intermittent resources (wind and solar) have an ELCC of 0 and all other supply resources have an ELCC of 1. The resulting ratios provide a comparison across provinces, highlighting where risks may emerge and where surplus capacity could enable interprovincial support.
2. **Intermittent Resource Analysis**
   The supply mix of each province was assessed between 2024 and 2040. Supply data came from the CER [3] or directly from Electricity Canada member-validated data [1]. The installed capacity of intermittent resources, solar and wind, was collected and expressed as a percentage of the total installed capacity. This percentage was calculated both in 2024 and 2040 for each province. Each province was plotted on a 2x2 matrix indicating the current and future quantity of intermittent resources. The location of each province on this matrix provided useful insight into the role of

[2] While not shown in this report, it is noted that TRM has a material impact on Alberta's intertie transfer capability and utilization, and that mitigation measures to increase allowable flows are expected in 2029 [4, 24].

intermittent resources and where there could be opportunities and challenges which enhanced east-west interties could enable or mitigate.

Insights and limitations

Opportunities were identified by synthesizing insights from the current state and future state analyses. It is important to note that these results are preliminary in nature and subject to a few limitations:

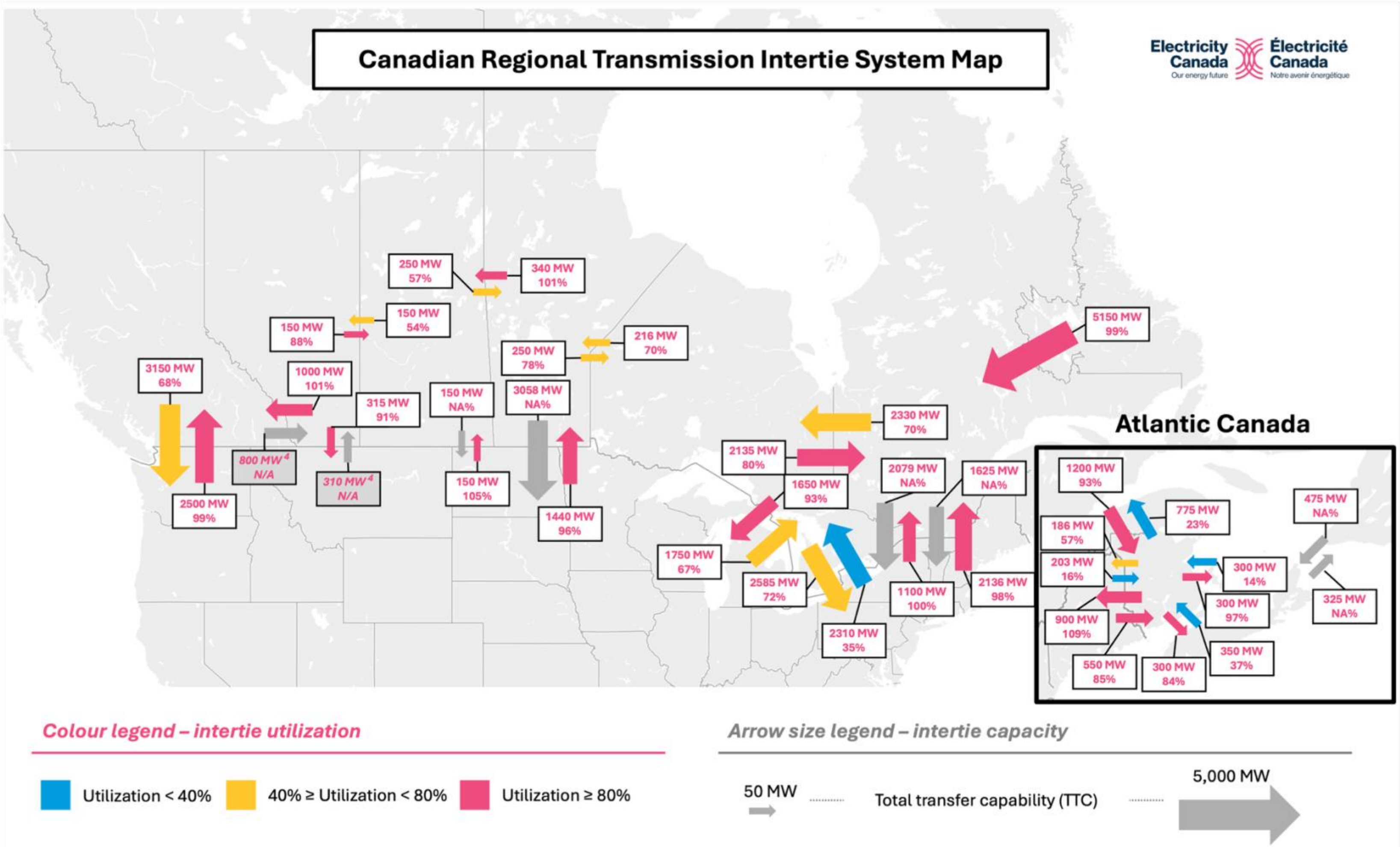
- Canada's territories were excluded from the study due to the absence of existing interties. It is noted that proposals exist for linkages between BC and the Yukon, and Manitoba and Nunavut that focus on access to provincial grids.
- The current state analysis draws on data from the past 3 years that reflects recent operating conditions: hydro-dominant provinces (BC, MB, and QC) have experienced drought in recent years [6], the ON–MB intertie remains capacity-limited due to an ongoing equipment failure [1], and the AB–SK intertie was only recently restored after being offline for over a year [1]. As a result, historical trends may not be fully represented, however, results still provide an illustrative view on intertie utilization.
- The future state analysis assumes an ELCC of 0 for intermittent renewables for comparability, which may overstate deficits in high-IRR provinces. Actual ELCC varies with system factors such as geographic diversity, peak-demand alignment, and available storage.
- The future state analysis also does not assess engineering, siting, or cost details; instead, it offers illustrative examples of how enhanced interprovincial transmission could support an optimized future grid. These examples are neither exhaustive nor prescriptive but highlight potential roles for expanded transmission and areas for further exploration.

The hope is that this preliminary analysis will inform a more comprehensive evaluation that would require detailed system planning and cost-benefit analysis, beyond the scope of this study.

Current state analysis

This section examines the present-day usage of Canada's intertie system, drawing on averaged data from the past 3 years related to total transfer capability (TTC) and peak demand utilization. This analysis is supplemented by several case studies that provide contextual detail. It is important to note that these findings offer a high-level overview over a relatively short and recent period and do not fully capture the historical context, planned future upgrades, or nuanced operational dynamics of each intertie. As such, the results should be interpreted as a snapshot in time rather than a comprehensive depiction of intertie usage.

Figure 2 – Current state of Canadian interprovincial intertie system. Arrow sizes represent the TTC; arrow colours represent the intertie utilization.[3, Error! Bookmark not defined.] N/A data and grey arrows indicate where data was not available.



[3] The intertie shown on the Saskatchewan-Manitoba border is the intertie connecting Manitoba to southern Saskatchewan (SK-S). The intertie connecting Manitoba to northern Saskatchewan was excluded from the study. The ON–MI and ON–MN interties are consolidated as both connect Ontario to regions operated by MISO.

[4] BC and Montana share a combined flow gate. TTC between the two interties totals 1,110 MW with a combined utilization of 55%. Energy flows into Alberta on the combined BC and Montana path are limited due to Alberta reliability considerations. Alberta is targeting to implement mitigation measures to increase allowable flows by 2029 [1, 4, 24].

Table 1 – Organization of interties by TTC and utilization. N/A indicates where data was not available.

Intertie		TTC (MW)
From	To	
NL	QC	5150
QC	ON	2330
ON	QC	2135
QC	NB	1200
AB	BC	1000
BC	AB	800
NB	QC	775
NL	NS	475
NS	NB	350
MB	SK-S	340
NS	NL	325
NB	PEI	300
NB	NS	300
PEI	NB	300
MB	ON	250
SK-S	MB	250
ON	MB	216
SK-S	AB	150
AB	SK-S	150

Intertie		Utilization (%)
From	To	
AB	BC	101%
MB	SK-S	101%
NL	QC	99%
NB	PEI	97%
QC	NB	93%
AB	SK-S	88%
NB	NS	84%
ON	QC	80%
MB	ON	78%
QC	ON	70%
ON	MB	70%
SK-S	MB	57%
SK-S	AB	54%
NS	NB	37%
NB	QC	23%
PEI	NB	14%
NL	NS	N/A
NS	NL	N/A
BC	AB	N/A

Canada's intertie network consists of 20 major connections, evenly split between 10 east-west and 10 north-south interties. The combined transfer capability is approximately 17 GW east-west and 28 GW north-south. Intertie utilization rates are high nationwide, averaging 72% for east-west interties and 79% for north-south interties. Notably, many interties operate near or above their TTC during peak periods, underscoring their critical role in supporting system reliability and facilitating economic and market outcomes.

Network capacity is unevenly distributed across the country. The largest interties are concentrated in north-south corridors, the Quebec–Ontario–Labrador corridor, and British Columbia. This distribution reflects historical priorities for hydroelectric development, reliability requirements, and export opportunities to the United States. East-west capacity is comparatively limited in the central provinces (i.e., Alberta, Manitoba and Saskatchewan), resulting in two distinct regions and constraining energy transfers from coast to coast.

Across the last three years, high utilization on most interties highlights their strategic importance in supporting both reliability and economic outcomes. Where utilization is lower, this can reflect directional asymmetry, energy flows predominantly in one direction due to differing provincial supply–demand needs. In these cases, lower utilization does not indicate limited value; the intertie can still provide critical reliability support and operational flexibility. For example, east-to-west interties in Eastern Canada, exhibit low utilization (e.g., 23% NB->QC), as they are primarily used for west-to-east transfers (e.g., 93% QC->NB), where they carry significant volumes to the Atlantic region.

Overall, the data demonstrates that Canada's intertie network plays a crucial role in supporting electricity reliability and facilitating energy markets, with most connections experiencing high utilization. However, the network's uneven capacity distribution and directional flow patterns create regional constraints, particularly in central provinces and the Atlantic region. These findings highlight both the strengths and limitations of the current intertie system, pointing to potential areas for future capacity enhancement and operational optimization.

Case Studies

To provide additional context, three case studies have been included to examine intertie operations in greater detail across different jurisdictions. These examples are not intended to highlight specific regions as issues or models. Rather, they are selected to offer a closer look on intertie usage and operational dynamics over a 3-year period from 2023 to 2025. By analyzing these jurisdictions in more detail, we aim to present a clearer and more nuanced understanding of the current state of intertie utilization across Canada.

Case Study #1: Atlantic Canada

Atlantic Canada's energy systems are in transition as provinces look to maintain reliability while phasing out coal-powered generation, refurbishing aging infrastructure, and bringing new renewable generation sources online. Electricity predominantly flows eastward, from Québec into New Brunswick then to the other provinces, creating directional utilization on interties.

New Brunswick is the critical hub for the Maritimes, annually importing up to 2 TWh from Hydro-Québec [7] and sending energy to Nova Scotia and Prince Edward Island. In view of the planned 2030 coal phaseout [8], the province is increasingly looking to firm imports as 40% of its electricity currently comes from the aging Point Lepreau nuclear station [9], and their primary dam (Mactaquac) requires a ~$7-9B refurbishment [10]. Upgrades to the supporting infrastructure for the Québec intertie are planned to be finished by 2029, but no new lines or major capacity additions have been finalized [1].

Nova Scotia is rapidly transitioning to wind and solar while phasing out coal-fired generation while importing electricity from New Brunswick and Newfoundland & Labrador, especially during low renewable output [11]. The intertie capacity with New Brunswick is set to be doubled via the Wasoqonatl Transmission Line, a new 345 kV corridor, which is forecasted to be in service by late 2028 and cost $685M with a portion of funding announced by the CIB and NRCan [12] [13].

Prince Edward Island imports 82% of its electricity from New Brunswick via submarine cables [1]. Wind provides approximately 58% of the island's domestic capacity, and they rely on largely off-island sources for reliable and cost-effective energy [14]. Recent reports warn that Prince Edward Island faces a projected 27% capacity deficit by 2033 unless new resources and intertie expansions are developed [15]. As such, talks are underway on the potential for doubling the existing intertie capacity with New Brunswick [1].

Case Study #2: British Columbia - Alberta

Traditionally, a net exporter of their abundant hydroelectricity, recently, imports into British Columbia have often approach the maximum allowed because BC's grid has faced multi-year droughts that cut hydro output by nearly 28% in 2024, requiring BC Hydro to import about 25% of its electricity needs from Alberta and the United States [16]. BC leverages imports from Alberta as Alberta's grid, rich in natural gas and growing wind capacity, complements BC's system to supply firm power during low hydro periods and winters peaks. Under non-drought conditions, market dynamics also favor BC importing low-cost Alberta power to engage in arbitrage by conserving water for future high-value exports. Conversely, BC supports Alberta during grid stress, such as the January 2024 cold snap [17], by exporting hydro during periods of lower generation from Alberta's renewables. Whie intertie utilization is currently westward as the AESO has stricter limits on imports into Alberta for reliability reasons, there are plans to enable the intertie to support full flow capabilities with updates within the next 5 years. These plans include transmission infrastructure upgrades estimated to cost $150M [18, 19] and the procurement of ancillary services to support full imports on the AB-BC/MT interties during all normal operating conditions [20].

Case Study #3: Ontario - Quebec

Ontario and Quebec each benefit through the use of strategic agreements that help make efficient use of excess seasonal capacity. The two provinces have complementary seasonal demand peaks (Ontario in the summer and Quebec in the winter) which enables the ongoing 2024 agreement for an annual capacity swap of 600 MW [1]. This active agreement is cost-effective for both provinces when considering alternatives including curtailing renewable electricity or building net-new generation capacity. Into the 2030s, under certain energy transition scenarios Ontario's grid may become dual peaking [21]. The IESO and Hydro-Quebec are continuing to evaluate the opportunity for increasing current intertie capacity through upgrades and new connections [1]. The IESO is undergoing an Eastern Ontario Bulk Planning study (set to conclude in 2026) to examine the system's capability for transfers to and from Quebec [1].

Building on this current state understanding of today's intertie system, the next section examines how these dynamics may evolve under future conditions.

Future state analysis

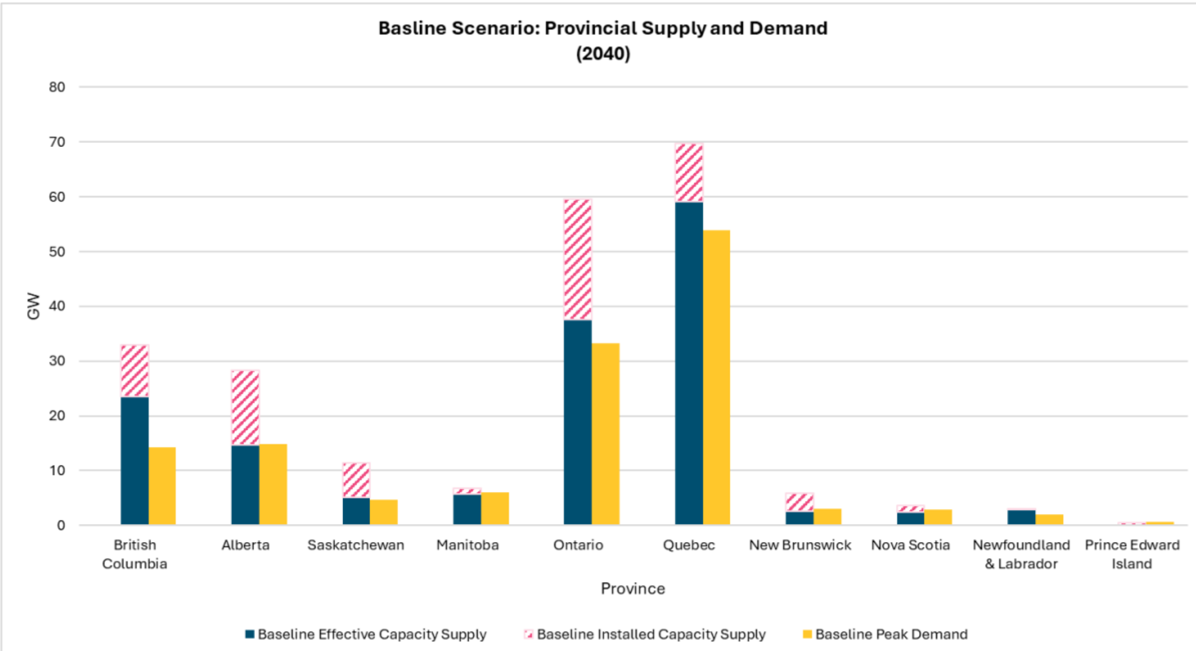
This section explores the future electricity system across Canada and aims to understand the potential future role of the intertie system. The first step seeks to understand which provinces might face a supply-demand surplus or deficit in the future. Provinces with the potential of being short supply (i.e., deficit) could be candidates for enhanced east-west interties to strengthen their system. On the other hand, provinces forecasted to be long supply could benefit from enhanced interties to increase exports to provincial neighbors. The second step evaluates the role of intermittent resources in each province's future supply stack. Provinces with a significant share of intermittent resources in their supply stack could benefit from enhanced east-west interties to enable improved reliability and energy export outcomes.

To complete the first step of the analysis, we compared provincial effective supply and demand under two scenarios: a Baseline and a Stretched scenario. The Stretched scenario is designed to address the limitations of point-in time forecasts, by accounting for planning uncertainty by layering in potential stressors such as higher-than-expected demand (e.g., extreme weather, outages, policy changes) and lower incremental supply (e.g., build delays, supply-chain constraints, drought). For the second step, we analyzed the share of intermittent resources in each province's supply mix for 2024 and 2040, mapping these on a 2×2 matrix to illustrate the evolving role of intermittent resources in each province.

Supply-demand results

This section compares each province's projected peak demand against its effective capacity under two scenarios: Baseline and Stretched. To understand future system adequacy, our evaluation focuses on effective capacity rather than installed capacity, as it reflects the ability of provincial generation resources to reliably meet peak demand. In Figures 3a and 3b, provinces with a positive difference between effective capacity and peak demand are projected to have a surplus of capacity relative to demand, whereas provinces with a negative difference may experience deficits in meeting demand with domestic generation. To note, installed capacity is shown for reference purposes only but is not included in the supply-demand ratio analysis. Table 2 normalizes the difference between effective capacity and peak demand as a percentage of peak demand, providing a clear view of relative surplus or deficit across provinces.

Figures 3a (top) and 3b (bottom) – Baseline and Stretched Scenario of forecasted peak demand and effective capacity supply (GW) in 2040, by province. Effective capacity assumes an ELCC of 0 for IRRs. Installed capacity is shown for reference purposes but is not included in the analysis.



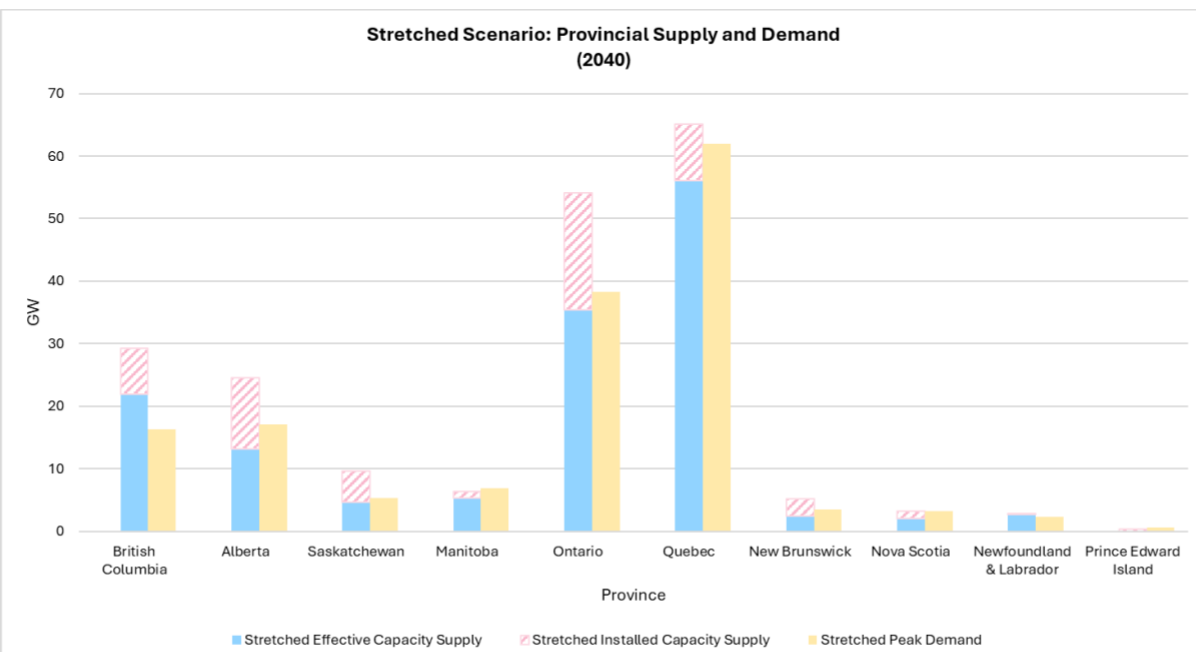


Table 2 – Effective capacity supply and peak demand ratio (%) in 2040, by province. The ratio is defined as (Effective Capacity – Demand) / Demand. (+/-) implies surplus or deficit of supply to meet demand. Effective capacity assumes an ELCC of 0 for IRRs. Provinces with potential deficits have been highlighted.

	Supply - Demand Ratio (%) in 2040	
Province	***Baseline***	***Stretched***
British Columbia	65%	34%
Alberta	-1%	-22%
Saskatchewan	12%	-13%
Manitoba	-5%	-22%
Ontario	13%	-7%
Quebec	10%	-10%
New Brunswick	-16%	-28%
Nova Scotia	-16%	-37%
Newfoundland & Labrador	47%	19%
Prince Edward Island	-90%	-94%

Provinces at risk of deficit

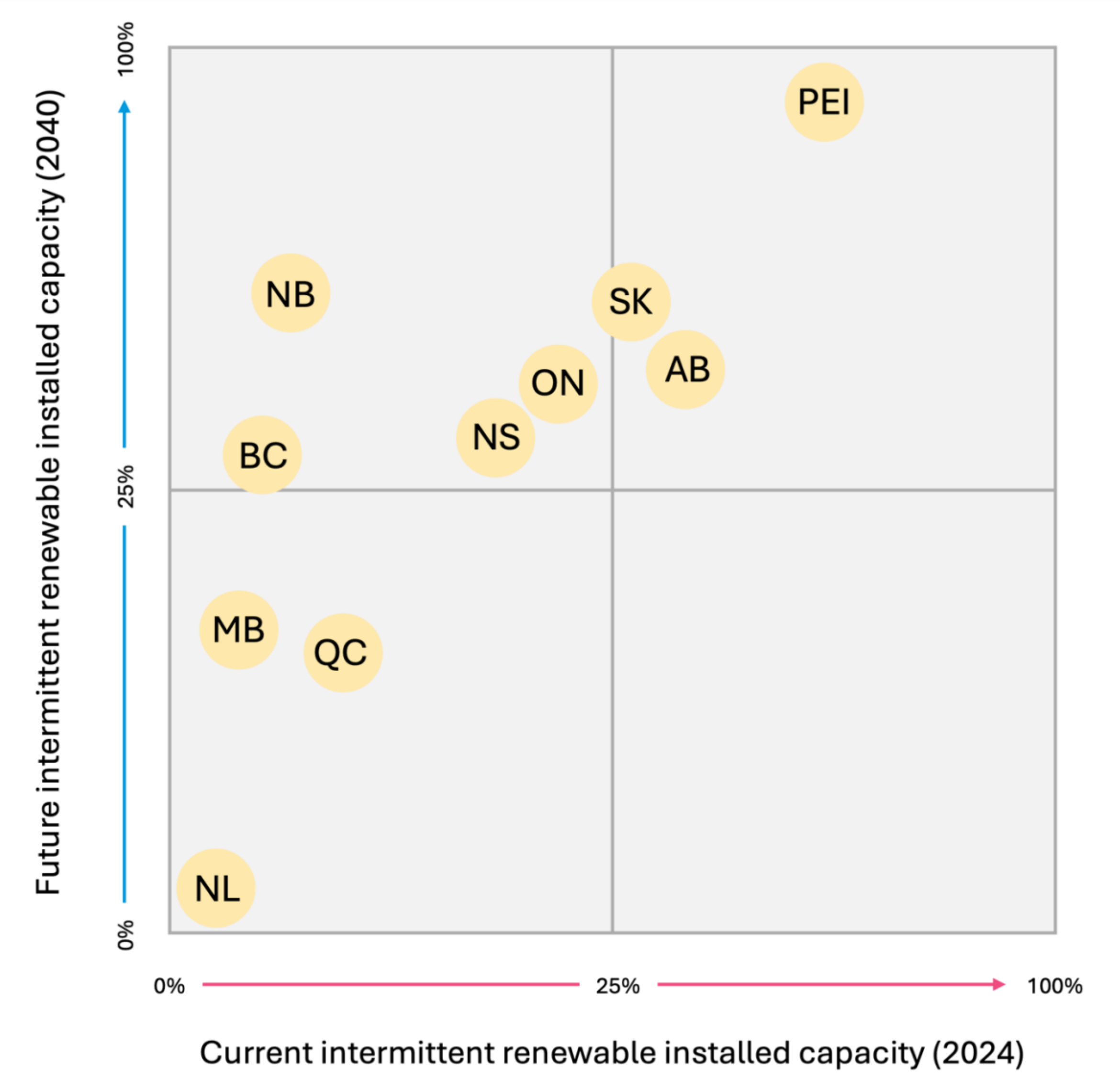
By 2040, under the Baseline Scenario, half of the provinces are projected to maintain positive supply-demand ratios, with British Columbia leading by a notable margin and Saskatchewan holding moderate surpluses. Ontario and Quebec are similar in standing with positive ratios, while Alberta and Manitoba may experience deficits, suggesting emerging constraints. Atlantic Canada shows a more varied outlook as Newfoundland & Labrador is the sole province that potentially will have a surplus, whereas the other eastern provinces may experience deficits.

Under the Stretched Scenario, these interprovincial trends change as increased demand and delayed growth in domestic effective capacity buildout leads to significantly reduced ratios across the country. British Columbia and Newfoundland are projected to be the only provinces to maintain surpluses in capacity. All other provinces see their effective capacity to peak demand ratio tested under stress; Saskatchewan, Ontario, and Quebec which all previously held moderate positive ratios may shift into potential deficits and baseline deficits may widen in Alberta, Manitoba, and the remaining Atlantic provinces. This scenario highlights the need to leverage forecasted surplus regions, particularly BC and Newfoundland & Labrador, to support their neighbouring provinces at risk of deficits, through enhanced intertie connections.

Intermittent resource results

The role of intermittent resources today and in the future is depicted for each province in Figure 4. Provinces in the bottom-left quadrant are **low adopters** of intermittent resources and continue to depend on traditional resources such as hydro power. Provinces in the top-left quadrant are **emerging adopters** of intermittent resources and are evolving their supply mix to include a significant amount of these resources in the future. Provinces in the top-right quadrant are the **high adopters** of intermittent resources who have significant intermittent capacity deployed today and aim to grow this out to 2040.

Figure 4 - Visual depiction of current and future intermittent resource deployment levels, by province.



From this data, we see that Alberta, Saskatchewan and Prince Edward Island[4] will deploy the largest relative quantities of intermittent resources. Meanwhile, British Columbia, New Brunswick, Nova Scotia, and Ontario plan to significantly grow their relative share of intermittent resources. All seven of these provinces might face reliability and resilience challenges with these increased levels of intermittent resource deployment. Interconnections enhance the utilization of variable resources, which will be critical as these provinces adapt to higher shares of intermittent generation. Newfoundland, Manitoba, and Quebec continue to rely on firm hydropower, natural gas, and nuclear to power their provinces. These provinces may be able to support the other seven provinces in meeting reliability and resilience goals through enhanced east-west interties.

These insights from the future state assessment combined with the current state assessment form the basis for identifying opportunities for enhanced interprovincial transmission, discussed in the next section.

[4] On-island / domestic generation currently only meets a minor portion of PEI's demand; the province imports 82% of its electricity from New Brunswick with talks on doubling intertie capacity in the future [1].

Example opportunities

This section builds on current and future state analyses to identify illustrative opportunities for enhanced interprovincial transmission. These examples demonstrate transmission's potential value under evolving conditions and highlight areas for further exploration.

Opportunity #1: Western Canada

Interties between British Columbia, Alberta, and Saskatchewan offer significant potential for regional optimization as all three provinces increasingly rely on intermittent resources. These connections could play a role to boost system resilience, enabling mutual support during supply disruptions or variability. The BC-AB intertie capability has been limited, and optimization of the existing infrastructure will lead to higher utilization [18], while the AB-SK intertie faces limited use and age-related asset challenges, rebuilding the line presents an opportunity to increase capacity[5]. Strengthening and better coordinating these interties would optimize resource sharing, balance supply and demand, and mitigate risks from intermittent generation, positioning Western Canada to manage future demand and reliability.

Opportunity #2: Manitoba

Currently, Manitoba has larger outward intertie capacity and utilization, suggesting it is a net exporter of electricity to Ontario and Saskatchewan, supported by its strong hydro resources. However, rising demand and limited new capacity may lead to future supply constraints, with neighboring provinces potentially holding surpluses. This creates an opportunity for Manitoba to import electricity and address supply gaps, especially as hydro-dependent provinces are vulnerable to variability during poor water years. Enhanced intertie use and coordinated planning with neighbors could boost Manitoba's resiliency, reduce supply risks, and ensure reliable service as demand grows.

Opportunity #3: Atlantic Canada

Interties from Quebec and Newfoundland and Labrador (NL) into Atlantic Canada present an opportunity to meet rising electricity demand and reduce vulnerability from intermittent renewables in New Brunswick, Nova Scotia, and PEI. Nova Scotia and PEI rely on imports from New Brunswick, and all three provinces experience adverse weather impacts simultaneously. Quebec and NL show surplus supply under both baseline and stress scenarios, while Nova Scotia and PEI face deficits. By expanding intertie capacity and enabling regional energy transfers, Quebec and NL can play a pivotal role in meeting the Atlantic provinces' future needs, advancing both reliability and cleaner supply objectives.

Opportunity #4: Ontario and Quebec

The Ontario–Quebec intertie exemplifies effective interprovincial collaboration, with both provinces optimizing energy flows through strategic agreements and infrastructure planning. Their complementary seasonal demand peaks enable efficient energy sharing and reduce the need for redundant capacity investments, even as both provinces plan significant future expansions. However, stressed scenarios reveal potential undersupply for Ontario and Quebec in 2040, -7% and -10% supply-demand ratio respectively. An integrated regional approach to east-west transmission could continue optimize existing assets, address supply challenges, and prevent costly overbuild.

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[5] The AB-SK intertie was recently returned to service after being offline for over a year due to an equipment failure. Plans are being explored to expand its capacity from 150 MW to 400-500 MW [1].

Conclusion and next steps

Electricity systems are developed under provincial jurisdiction, with transmission infrastructure primarily connecting local generation to domestic demand. As demand increases due to population growth, transportation and industrial electrification, and economic expansion (particularly in emerging sectors such as data centres and critical minerals mining), interprovincial transmission will be essential for reliably and affordably integrating new energy sources.

Our study holds that Canada's network of east-west interties is effectively utilized, and contributes, per design, to system resilience, reliability and optimization. Over the next 10-25 years, forecasts suggest that some provinces may experience electricity surplus while others could face constraints. This presents opportunities to further optimize interprovincial transmission in response to accelerating demand and the growing importance of intermittent energy resources. However, it is important to note that these demand forecasts are inherently uncertain, increasing the risk associated with planning and developing long-term, capital-intensive energy systems, particularly if demand does not materialize where and when anticipated.

Provincially interconnected transmission infrastructure presents a significant opportunity for Canada to meet future electricity demand in an efficient and cost-effective manner, while also advancing economic growth and nation-building objectives. Taking proactive steps now to prioritize interprovincial transmission can help avoid the inefficiencies and higher costs associated with each province independently expanding its own electricity system. Elevating transmission to a central role in energy strategy, through regionally coordinated and integrated planning, will help ensure reliability, affordability, sustainability, and economic development. Adopting a comprehensive, system-wide approach that considers all resource options and timelines will maximize the effectiveness and resilience of Canada's electricity system.

While there is increasing appreciation of the benefits of interprovincial transmission and coordinated regional electricity planning, several key barriers must be addressed to fully capture these opportunities. Targeted action in these areas will be important to advance interprovincial transmission and to establish a more integrated and efficient electricity system in Canada. Barriers include:

Market Structures: Over the past 50 years, provinces have developed markedly different electricity market structures, ranging from fully deregulated markets (e.g., Alberta), to competitive wholesale markets (e.g., Ontario and what is emerging Nova Scotia), to regulated markets (e.g., BC, Manitoba, and Quebec). These differences create challenges in forming mutually beneficial, long-term contracts necessary for capital-intensive, long-lived assets like transmission interties. Historically, provincial interties have prioritized system reliability, with exports more often directed to the US due to larger demand and more attractive market mechanisms.

To advance interprovincial transmission, it is essential to develop fair cost allocation frameworks that equitably distribute costs and benefits among participating provinces, private entities, and the federal government, reflecting the value derived from increased reliability, reduced costs, or environmental improvements. Mechanisms such as regional capacity markets or transmission rights could support the creation of long-term revenue streams for provinces or private investors, incentivizing both the optimization of existing infrastructure and new transmission development. Consideration must also be given to enabling frameworks that allow for cost recovery and reasonable returns on transmission investments, while accommodating the diversity of provincial electricity market and regulatory structures. This will help prevent transmission development from being hindered by market differences.

→ **Next step:** Explore alternate and additional market instruments that may enhance the competitiveness and broader role of interprovincial transmission interties. These instruments must be designed to function within, and respect, the varying market structures and jurisdictions of each province.

Economic: Canada's vast geography and low population density create financial challenges for developing new interprovincial intertie infrastructure. To fully understand the value of enhancing east-west interties, it is important to consider not only technical factors but also the broader national and regional strategic and macroeconomic benefits.

A key element of this evaluation is benefit accrual, which refers to the process of aggregating and allocating benefits of transmission projects among different parties. Calculating benefit accrual helps quantify the total value a project can deliver and provides a transparent basis for comparing benefits to costs. This approach supports fair and equitable cost-sharing among participants by aligning each party's funding responsibility with the benefits they receive.

→ **Next step:** Strengthen the business case for east-west transmission in Canada by developing benefit accrual assessments and implementing policy mechanisms that incentivize investment and enable coordinated planning across jurisdictions.

Governance and planning: Clear roles and responsibilities for regional coordination are essential to support optimized regional transmission planning. Currently, electricity generation and transmission fall primarily under provincial jurisdiction, resulting in differing regulations, standards, and priorities across provinces. Meanwhile, the federal government regulates international electricity transmission. This fragmentation can complicate efforts to pursue integrated, cross-provincial solutions. Furthermore, the absence of an overarching national or interprovincial framework to facilitate intertie transmission projects adds to the complexity of coordination. Examples of overarching system-level planning bodies include Europe's ENTSO-E [22] and Australian Energy Market Operator [23].

→ **Next step:** Establish an interprovincial or regional framework that accelerates transmission planning by clearly defining federal and provincial roles. For example, the framework could assign the federal government responsibility for coordination, funding, and regulatory support, while provincial governments and utilities oversee local implementation and operations.

Policy and regulation: Reduce barriers that currently limit interprovincial collaboration. Provinces have distinct energy strategies, and some maintain self-sufficiency regulations that can impede broader national alignment and restrict opportunities for shared infrastructure development and interprovincial system optimization. In an era of more uncertain demand forecasts, prioritizing self-sufficiency at the provincial level may result in overbuilding of infrastructure and lost interprovincial optimization. Harmonizing electricity market rules and regulations across provinces would facilitate electricity trade and make interprovincial transmission projects more attractive to investors and stakeholders.

→ **Next step:** Conduct a comprehensive, collaborative review to identify and address regulatory barriers to east-west electricity trade and interprovincial transmission planning, culminating in a coordinated plan with recommendations for harmonizing market rules, revising self-sufficiency regulations, and aligning provincial energy strategies.

Financing: Significant investment will be required to build the future electricity system. Unlike other types of infrastructure, which are often funded through a combination of users and taxpayers, electricity infrastructure is nearly always paid for directly by users. This traditional funding model places the financial responsibility primarily on ratepayers, whereas other public infrastructure benefits from broader taxpayer support. As the electricity sector is now being asked to undertake complex capital-intensive projects of national importance, the existing ratepayer-focused model may not be sufficient or equitable. There is an opportunity to optimize these investments by coordinating and sharing costs not only at the federal level, but also among provinces. Provinces will not always equally share the benefits of interties and thus a cost-benefit framework between provinces would enable the best cost-sharing path between provinces. Cost-sharing mechanisms, alongside federal support, can help distribute financial risk, align interests, and ensure that the benefits and responsibilities of new transmission infrastructure are shared equitably. This is especially important for projects that deliver national benefits, such as emissions reduction and improved grid reliability. In addition, targeted grants, low-interest loans, or loan guarantees from the federal government can further reduce high upfront costs of transmission projects.

→ **Next step:** Establish a collaborative working group of federal, provincial, regulatory, and industry representatives to review financial barriers to transmission development and create a coordinated financing framework that defines cost-sharing and identifies where targeted federal support can most effectively accelerate investment and project delivery.

Provinces are already planning the next generation of electricity systems for 2050, and decisions made today will shape those outcomes for decades. If interprovincial transmission is not proactively assessed and considered now, Canada risks locking in costly, fragmented infrastructure that limits flexibility and resilience. Electricity Canada is uniquely positioned to assume a leadership role in advancing interprovincial transmission and regional electricity planning. By fostering alignment among stakeholders, Electricity Canada can co-develop well-founded recommendations regarding market incentives, structured regional planning, reducing regulatory barriers, establishing cost-sharing mechanisms and providing targeted support. This represents a significant opportunity to ensure that investments in transmission infrastructure support affordability, strengthen system resiliency, and advance Canada's long-term economic and climate objectives.

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