RIGS Plants Assessment Report

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I. EXECUTIVE SUMMARY

KEY FINDINGS

New Brunswick Power (NB Power) has identified a potential near-term supply shortfall and is proposing the Renewable Integration and Grid Security (RIGS) project to address the emerging reliability needs. The Brattle Group (Brattle) was retained to assess whether the RIGS project, which consists of a new 400 MW gas-fired generation facility with dual fuel capability, is justified based on system reliability and operational considerations.[1]

Our assessment began with a review of NB Power's overall analytical approach. We confirmed that the methodology taken by NB Power aligns with accepted industry practices. We then examined the key planning assumptions underlying NB Power's conclusion that the RIGS project is necessary. Brattle did not conduct independent detailed reliability modeling; rather, we reviewed recent planning studies performed by NB Power and other stakeholders, conducted a sensitivity analysis and assessed the reasonableness of their conclusions against established practices and professional judgment.

Based on our review, we find NB Power's decision to pursue the RIGS project within its service territory to be both reasonable and appropriate, given the reliability and planning criteria evaluated together with operational requirements.[2]

NEW BRUNSWICK RELIABILITY

The investment timeline for the infrastructure-heavy power industry requires planners to 1) start building now what you expect to need by the end of the 5 years, or be contracted with others to do so, 2) finalize plans now for what you hope to build or contract in 5 to 10 years, and 3) plan for the period beyond 10 years, while recognize the uncertainties in those plans. The standard utility planning practice today is roughly built around these timelines and starts by establishing a load forecast and then designing a resource portfolio to meet the projected demand. Details of the resource portfolio design vary by the future window, with a more granular analysis performed for the near term. NB Power's approach aligns with this standard. In developing the future resource portfolio, NB Power uses the Reliability Assessment Program

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1 Brattle's role as an outside expert is to assess whether this investment, at this period in time, is prudent for NB Power to meet certain reliability standards.

2 NB Power's decision is subject to approval by the New Brunswick Energy and Utilities Board (NBEUB).

requirements established by the Northeast Power Coordinating Council (NPCC), which is shared with other Maritimes Area utilities, namely Nova Scotia Power, Maritime Electric (serving Prince Edward Island), and the Northern Maine Independent System Administrator (NIMSA). The requirement is a loss of load expectation (LOLE) of no more than 0.1 days per year. This reliability standard typically translates to a 20 percent capacity reserve margin (excess capacity above projected peak demand). While the Maritimes Area utilities have historically met the NPCC's resource adequacy criterion using this capacity reserve margin, the most recent Maritimes Resource Adequacy Review found LOLE exceeding 0.1 in 2025 and 2027.[3]

NB Power's planning process involves three steps. First, it calculates future capacity needs based on this 20 percent reserve margin. It then conducts additional analysis to confirm that the resulting generation portfolio meets the LOLE criterion. Then for the immediate future, it looks at other operational requirements that may not be adequately captured in the longer-term analysis. Using this approach, and recognizing the three investment timelines, NB Power identified potential capacity shortfalls in the near future (by around 2028) under certain conditions and subsequently proposed the RIGS project to maintain system reliability consistent with NPCC standards.

Brattle Review

Once we confirmed that the analyses approach is reasonable, we then reviewed NB Power's actual analyses, starting with the load forecast. As part of this review, we compared NB Power's load forecast to neighboring regions' forecasts and looked at assumptions behind key drivers of load growth, such as heating electrification (the Maritime Area consumes the maximum amount of electricity during winter, which heating electrification will increase), population growth, and industrial expansion and decarbonization. Overall, we observed that NB Power's projected load growth is the lowest among neighboring regions (the three other Maritimes Area utilities, Hydro-Québec, and ISO-New England). Many neighboring utilities are expecting higher load growth through electrification while New Brunswick has already electrified a large portion of its load. We also observed that nearly two-thirds of New Brunswick's estimated gross load growth will be offset by Demand Side Resources (DSR), such as Distributed Energy Resources (DER) and Demand Response (DR) programs.

We then reviewed NB Power's resource portfolio analyses (after satisfying the 20% capacity reserve margins) that led to the development of RIGS. As part of this analysis, NB Power looked

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3 2024 Maritimes Area Interim Review of Resource Adequacy. NPCC. October 29, 2024. ("2024 Maritimes Interim RA Review")

at potential unavailability of its existing resources, such as those caused by outages associated with maintenance or retrofits of the existing aging resources, or forced outages that could be caused by weather, such as wind turbines halting generation when the temperature drops substantially (e.g., below negative 30 degrees Celsius). We did not find any assumptions that we would consider unreasonable for planning purposes through these reviews.

Brattle Sensitivity Analysis

Upon confirming the reasonableness of NB Power's analyses approach and assumptions, we performed a separate assessment of the sensitivities of planning reserves and operational requirements to variations in key load forecast drivers and supply availability. We confirmed that changes in population growth or temperature change at levels observed in recent history, as well as potential supply reductions due to scheduled maintenance or retrofit risks could tighten the supply-demand balance and further justify the need for RIGS. On the other hand, we observed that a P90 load forecast (i.e., low load growth that has a 90% chance that the actual load will be higher than the forecast) would eliminate the needs for RIGS. Given that NB Power's projected load growth is the lowest in the Maritime region, and that two-thirds of the gross load is expected to be offset by DSR, we conclude that there is asymmetric risk with that of higher load being much more significant. In our experience, relying on prudent investment, albeit at higher costs, is far more preferable to risking capacity shortages, which could lead to service interruptions. Additionally, it may be prudent to err on the side of timely additional supply, due to unusually high levels of uncertainty regarding the supply chain for many types of resources, including gas turbines and generators, electrical switchgear, and transformers. Historically, the industry has typically not faced such constraints and, therefore, has not experienced a need to build additional buffers into its supply plans.

Considering Alternatives to RIGS

Having confirmed the capacity represented by RIGS is needed for reliability, we looked at alternative options, including importing firm power from neighboring regions. For this analysis, we looked at two key factors.[4] One is the import capabilities together with existing contracts

[4] We also considered a third factor, NB Power-specific operational constraints. North American Electric Reliability Corporation (NERC) standards require NB Power to maintain contingency reserves equal to the system's Most Severe Single Contingency (MSSC), typically the Point Lepreau Nuclear Generating Station at 715 MW. NPCC imposes additional requirements, including synchronized reserves and thirty-minute reserves equal to half the second-largest contingency (often Belledune at 467 MW). These requirements could place an upper limit of how much NB Power can willingly import because relying on more than 466 MW of firm imports from a single neighboring region could lead to increasing operating reserve needs.

(which we assumed to stay constant in future years) that may be using some of the tie-line capacities. In general, there is not enough firm tie-line capabilities to accommodate a 400 MW import. The other is if there is excess supply in the neighboring regions. In general, as we observed from higher load growth projected for these regions, all neighbors, including Hydro-Québec, show forecasts to become capacity short in the near future. Also, with the exception of ISO-New England, these neighboring regions are winter peaking, indicating they will likely not have excess capacity available to share with New Brunswick when NB Power may need it the most. The current forecasted supply tightness in neighboring regions together with import/export limitations of tie-lines, and other qualitative considerations (such as the geopolitical risks with the U.S., or the limited availability of natural gas in Prince Edward Island) suggests building or contracting an asset outside of New Brunswick and importing is not a preferred option. And while future system upgrades, such as the planned transmission projects, may alleviate these constraints, they will likely not be available in a timely manner to allow imports by 2028.

Economic Benefits of RIGS

We then looked at the potential economic implications of developing RIGS within New Brunswick. First, it avoids the risk of securing firm transmission in external jurisdictions while also allowing the RIGS generators to address voltage issues within New Brunswick. Second, it avoids potential higher costs of operations and maintenance of the RIGS assets once it is put in service, such as those caused by tariffs or even for simply dispatching field engineers for inspection or maintenance needs. The same could be said for fuel supply (i.e., natural gas procurement) as well. Third, there are both direct and indirect economic benefits of RIGS, including job creation and tax revenues, and recuring revenues to support local services and infrastructure. Fourth, the foreseen challenge of retiring certain generation types to comply with federal and provincial policies by 2030 or 2035 indicates there will be energy sales opportunities to neighboring systems for RIGS. This leads to the belief that the risk of RIGS becoming a stranded asset is very low.

Conclusions

Our review has found that NB Power’s assessment supporting the need for RIGS is grounded in sound analysis and reasonable assumptions and, thus, that building additional capacity within New Brunswick is a prudent decision. There exists some potential for short-term overinvestment should the most favorable demand and supply conditions materialize. However, we understand that the economic consequences of over- and under-investment are asymmetric.[5] Specifically, the costs associated with underbuilding system capacity (thereby increasing the likelihood of supply shortfalls or service interruptions) typically exceed the incremental costs to ratepayers resulting from modest overinvestment. Accordingly, from a regulatory and system planning perspective, it is generally more prudent to tolerate a small degree of excess capacity rather than risk the significantly higher economic and societal costs associated with insufficient investment.

The retirement schedule of large, existing generation facilities in the Maritimes Area further reduces the risk of overbuild in the medium to longer term.[6] That is, the probability that the RIGS assets become stranded is low, given the anticipated higher load growth in the Maritime Area and regulatory trends that are accelerating the retirement of certain generation assets. Investment in RIGS would enhance NB Power's ability to export electricity to neighboring jurisdictions and preserve the economic value of existing and future energy and capacity agreements while hedging for the potential upswing in New Brunswick's load growth.

The remainder of this report is organized as follows:

- Section II (Introduction) provides an overview and background of the study.
- Section III (New Brunswick Reliability Outlook) looks at the approach NB Power has taken for the analyses, reviews the supply and demand balance of New Brunswick, and culminates with a sensitivity analysis of key demand drivers.
- Section IV (Alternative to RIGS) looks at the potential for importing the needed capacity from neighboring regions.
- Section V (Economic Considerations) looks at the comparative benefits of building RIGS within the NB Power service territory.
- Section VI (Conclusions) summarizes the findings of the Brattle review.

The appendices include a glossary and acknowledgement forms of Brattle's expert witnesses.[7]

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5 Neuhoff, K. & De Vries, L. Insufficient incentives for investment in electricity generations. Utilities Policy 12, 253–267 (2004); De Vries, L. & Heijnen, P. The impact of electricity market design upon investment under uncertainty: The effectiveness of capacity mechanisms. Utilities Policy 16, 215–227 (2008).

6 NB Power is scheduling large retirements by 2040, which further reduces the risk of RIGS becoming stranded assets.

7 Brattle has been retained by NB Power to serve as an independent expert to the NBEUB to evaluate the reasonableness of NB Power's assumptions underlying its conclusion regarding the need for the RIGS project, including both the need for additional capacity to maintain reliability and the potential for alternative options (e.g., firm imports from neighboring regions) to meet the capacity need in lieu of in-province resources.

II. Introduction

New Brunswick Power Corporation (NB Power) completed its last integrated resource planning (IRP) study in 2023.[8] Although the 2023 IRP concluded that there was limited need for additional firm capacity before 2030, evolving system conditions have since changed this outlook. New Brunswick has entered a period of sustained peak demand growth, driven by population increases, expansion in residential and industrial customer segments, and the accelerating electrification of heating, transportation, and industrial processes. Under these updated demand forecasts, NB Power's 2024 Resource Adequacy Report identified the potential for a capacity shortfall by as early as 2028.[9] To address this potential deficit, NB Power is seeking approval to enter into a tolling agreement for the Renewable Integration and Grid Security (RIGS) project, a proposed 400 MW dual-fuel combustion turbine generation facility, with a targeted commercial operation date of August 1, 2028.[10]

Brattle was engaged to evaluate whether the proposed investment is justified based on reliability criteria and the availability of alternative options to meet the identified reliability need. Specifically, we were asked to validate assumptions that NB Power has made in its analysis, including both the reasonableness of NB Power's assessment of the need for such additional capacity, as well as the availability of long-term firm import contract options from neighboring jurisdictions for the volume of capacity (i.e., 400 MW) contemplated.[11]

The review was performed in multiple steps. We first reviewed the overall analyses approach taken by NB Power, including various materials prepared by NB Power and other regional planning studies.[12] Upon confirming that the approach is consistent with accepted industry practices for reliability-driven resource investment, we reviewed the assumptions that led to the conclusion (i.e., the necessity of developing RIGS). This step involved reviewing the load forecast and supply portfolio. Upon reviewing both supply and demand, we analyzed the combined information to assess the supply/demand balance and its sensitivities to assumptions

8 NB Power is mandated through legislation to refresh the IRP every three years and reflect the changing energy landscape and customer expectations.

9 Resource Adequacy Report. New Brunswick Power. March 18, 2024.

10 The Nova Scotia Independent Energy System Operator (NS IESO) recently approached NB Power with a proposal to increase the RIGS Project's capacity to 500 MW, under which NS IESO would purchase 100 MW of capacity and NB Power would retain the remaining 400 MW.

11 The scope of this review did not include an evaluation of the reasonableness of NB Power's procurement approach, the specific type of capacity selected for procurement, or the commercial terms of the proposed tolling agreement.

12 These are cited throughout this report.

of key drivers. We further looked at options for securing additional supply through firm imports. This involved assessing potential supply surpluses in neighboring regions and the extent to which any identified surplus could be transferred to NB Power on a firm contractual basis. Finally, we concluded that building RIGS within NB Power's service territory has various comparative benefits than importing from external jurisdictions.

This report provides a description and quantification of the reviews we performed and summarizes the findings. The remainder of this Section provides background information, including an overview of NB Power and New Brunswick, and a description of the RIGS project.

NB Power and New Brunswick

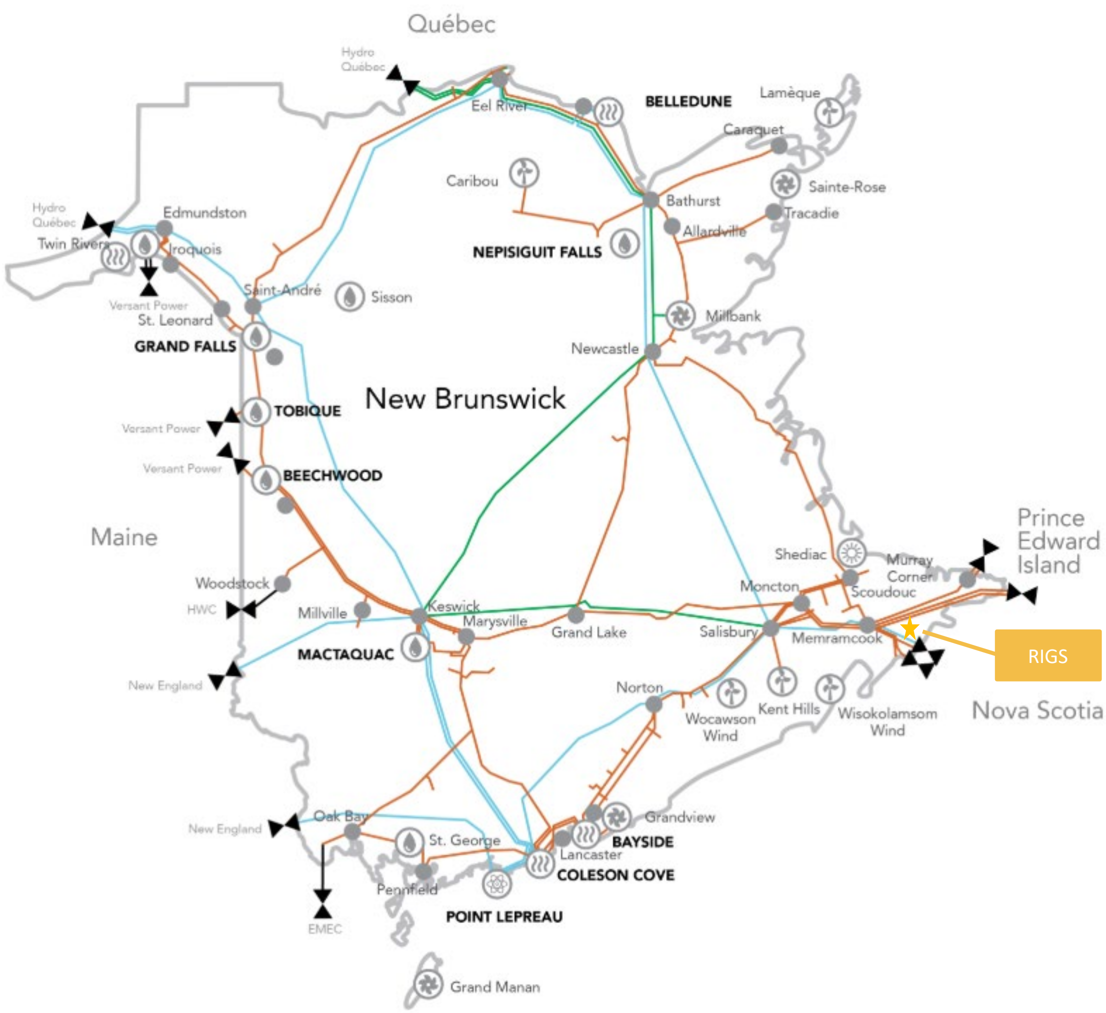
NB Power is a vertically integrated electric utility that has been serving most of the Canadian province of New Brunswick for over 100 years.[13] It is a Crown Corporation owned by the government of New Brunswick. Today, NB Power serves a net-peak demand of approximately 3,100 MW and net-annual domestic consumption of 15 TWh (nearly 19 TWh including exports) through its generation resource portfolio with an installed capacity of approximately 3,800 MW.[14,15] The NB Power system is electrically interconnected to Nova Scotia, Maine (both ISO New England and Northern Maine Independent System Administrator), Prince Edward Island, and Québec. NB Power is the Reliability Coordinator for the Maritimes Area, a winter peaking system which include jurisdictions and regulators of New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine. Figure 1 below shows the New Brunswick system.

[13] Saint John Energy, Energy Edmunston, and Perth-Andover Electric Light Commission provide services to their respective localities. In 2022/2023, NB Power supplied approximately 92% of total in-province electricity demand.

[14] These values are net of DSR.

[15] The portfolio of 14 generators includes hydro, coal, natural gas and diesel-fired generators, a solar farm, and the Point Lepreau nuclear plant. An additional 609 MW of resources, including 514 MW of renewables, are provided by third parties through power purchase agreements (PPAs). In addition, NB Power has successfully negotiated five additional PPAs for up to 500 MW of new cost-effective renewable wind energy projects led by First Nations communities. These agreements are in addition to the Neweg wind project, which recently (late fall of 2024) began delivering wind energy to New Brunswick's system.

FIGURE 1: NEW BRUNSWICK TRANSMISSION SYSTEM MAP[16]



The Government of New Brunswick has provided a decarbonization roadmap through its Climate Change Action Plan to reach net-zero emissions province-wide by 2050.[17] Specifically for the electricity industry, the policy requires the province to become carbon neutral (net zero supply requirement) by 2035. Federal policy also requires NB Power to phase out coal use at its Belledune Generating Station by 2030.

Pursuing federal and provincial policy goals comes with challenges, as a large portion of NB Power's generation infrastructure was developed in the 1950s through the 1970s and various

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16 NB Power System Map. Energie NB Power website. Last accessed: October 20, 2025.

17 In 2023, approximately 80 per cent of New Brunswick's energy came from carbon-free sources. In 2024, this was at 66%.

assets are approaching (or surpassing) their economic life, requiring replacements and/or refurbishment.

The Point Lepreau Nuclear Generating Station (PLNGS) is New Brunswick's largest source of clean energy. However, the facility has experienced significant operational challenges in recent years. Between 2015 and 2025, its annual capacity factor fluctuated from a high of 89.2 percent to a low of 27.4 percent (in the 2024/2025 period.) Aging infrastructure has contributed to this volatility. For instance, in 2024, a scheduled 100-day maintenance outage beginning in April was extended through early December to address the unexpected deterioration of stator bars, which required replacement. A subsequent major overhaul is planned for the 2025/2026 operating cycle.[18]

The Mactaquac Generating Station is a run of the river hydro facility with six units that supplies over 12% of New Brunswick's electricity needs. The facility began generating electricity in 1968. Since the 1980s, NB Power has observed structural deterioration of dam concrete, including swelling and cracking, thus requiring substantial annual maintenance and repairs. NB Power has developed a plan (the Mactaquac Life Achievement Project, or MLAP) to address these issues to ensure the station can operate to its intended 100-year lifespan. The proposed MLAP will replace older equipment on a unit-by-unit basis over time so only one unit is out during the winter peak period.[19]

Against this backdrop, NB Power has set out the following initiatives for 2025/2026:

- Progress the planning, engineering, regulatory matters and procurement activities needed to initiate Government of New Brunswick approval for the MLAP.
- Execute the PLNGS's generator rewind outage safely, on time and on budget.
- Continue to pursue partnership opportunities to achieve improved PLNGS performance.
- Determine new nuclear requirements to ensure energy security as part of the province's net-zero plan.
- Progress the 2026 IRP to refresh NB Power's strategy for achieving a net-zero electricity system.
- Complete engineering assessment to determine the viability of using alternative fuel at the Belledune Generating Station.

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18 NB Power News Webpage. Energie NB Power website. Last accessed: October 20, 2025.

19 We also note that NB Power's run-of-the-river hydro generating system is highly dependent on weather patterns like rainfall and snowmelt. Annual hydro generation has ranged from 82% to 123% of the planned output over the past decade.

- Finalize power purchase agreements with successful proponents in response to the Request for Expression of Interest to provide cost-effective renewable and energy storage solutions.
- Progress the planning work required for the RIGS.

This report is focused on the last initiative—to assess whether the RIGS project is justified based on system reliability and operational considerations over the next five to ten years.

THE RIGS PROJECT

The RIGS project is the first firm generation capacity expansion project for NB Power in over two decades.[20] Recently (following its 2023 IRP[21]), NB Power identified a potential shortfall in generation capacity, beginning in the mid- to late-2020s. To mitigate the risk of energy shortfalls, NB Power issued a Request for Expressions of Interest in June 2024 for the development of a new generation facility with a capacity of up to 500 MW. The proposed facility is intended to provide backup generation during periods of limited renewable energy availability, especially during extreme weather events and peak demand conditions. NB Power identified the solution (RIGS project) as 400 MW of dual-fuel combustion turbines and grid stabilizing synchronous condensers, which is expected to remedy the potential supply shortage by providing ramping needs to integrate higher penetrations of renewables. NB Power plans to install the RIGS project along Route 940 in Midgic, Centre Village on NB Power owned land where it can also address local transmission issues (e.g., voltage support).

Given the investment size, NB Power needs to seek approval from the New Brunswick Energy and Utilities Board (NBEUB) to move forward with the RIGS project.[22] We understand that the NBEUB will review the prudency of the investment.[23]

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[20] NB Power announces new generation capacity expansion project and development partner. Energie NB Power website, July 14, 2025. Last accessed: October 20, 2025

[21] 2023 Integrated Resource Plan: Pathways to a Net-Zero Electricity System. NB Power. 2023.

[22] The Electricity Act assented June 2013 (available at: https://laws.gnb.ca/en/tdm/cs/2013-c.7/) requires NB Power to seek approval for capital investments larger than $50 million.

[23] NBEUB has recently stated (in the context of transmission projects) that: 1) A project will be considered prudent if it is within the range of solutions that a reasonable Planning Authority and Transmission Planner in the position of NB Power could have selected based on the circumstances known to it at the time of the application for approval., and 2) A positive net present value assessment of the sort adopted in Matter 375 is not an appropriate measure of prudence in cases where the purpose of a proposed project is to meet performance requirements imposed by a standard to which NB Power is bound.

III. NEW BRUNSWICK RELIABILITY OUTLOOK

Reliability planning over both the long term and the more immediate operational timeframe is a critical activity for the electric power industry. The power system must maintain a continuous, moment-to-moment balance between supply and demand. Even modest imbalances, if sustained, can trigger grid instability, curtailments of generation or load, or, in the most severe case, system collapse. For customers, the value of avoiding such events is far greater than the average cost of doing so. Service interruptions, such as outages, not only impose significant economic losses but also create safety risks. This is especially true in a winter-peaking systems like New Brunswick, where electrified heating is widespread. Service interruptions in winter can expose households to immediate danger, making reliability not just a technical challenge but also a public health and safety imperative.

Carrying additional capacity reduces the likelihood of such events, and the avoided costs from doing so generally outweigh the additional cost of that capacity.[24] Therefore, it is deemed economically prudent to carry excess capacity on the system, often known as a "reserve margin." Defined as the percentage of installed dependable capacity in excess of coincident peak demand, the reserve margin serves as a buffer to accommodate outages of generation resources, variability in load and renewable output and their forecast error, and ancillary services needs.

Industry reliability standards codify the required balance between adequacy and cost. The North American benchmark for resource adequacy is the "1-in-10" Loss of Load Expectation (LOLE) criterion, which stipulates that the expected curtailment of firm load due to insufficient generation should not exceed one day in ten years. Meeting this standard requires probabilistic resource adequacy modeling, incorporating assumptions about load growth, forced outage rates and maintenance schedules for generators, capacity accreditation for resources (especially for those with variable outputs), transmission import capability, and planned resource additions or retirements.

NB Power is the recognized Reliability Coordinator for the Maritimes Area. NB Power's Transmission & System Operator division states that it "oversees the reliable operation of the Maritimes Area (New Brunswick, Nova Scotia, Prince Edward Island and Northern Maine)" in its

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[24] Neuhoff, K. & De Vries, L. Insufficient incentives for investment in electricity generations. Utilities Policy 12, 253–267 (2004).; De Vries, L. & Heijnen, P. The impact of electricity market design upon investment under uncertainty: The effectiveness of capacity mechanisms. *Utilities Policy* **16**, 215–227 (2008).

role as a Reliability Coordinator.[25] NPCC resource-adequacy reviews likewise identify NB Power as the Reliability Coordinator for the Maritimes Area.[26]

As the Reliability Coordinator for the Maritimes Area (New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine), NB Power has responsibility for ensuring compliance with these adequacy metrics at both the provincial and regional levels.[27] This includes establishing reserve margin requirements, validating those against probabilistic adequacy studies, and, when necessary, securing firm capacity or imports to close projected deficits. Currently, the reserve requirement is largely met with hydro and thermal capacity.

For its provincial grid, NB Power plans for a reserve margin equal to the greater of the capacity of its largest generator (for operations planning) or 20% of the forecast firm peak demand (for long-term planning). At the Maritimes Area level, a 20% margin on coincident peak is used as a baseline for long term planning, with further validation against the LOLE standard.[28]

The 2022 Maritimes Area Comprehensive Review of Resource Adequacy determined that a 20% reserve margin corresponded to a LOLE of 0.081 days/year, or roughly a 1-in-12 standard, slightly more conservative than the 1-in-10 benchmark. This translated to approximately 40 MW of capacity above that required to achieve a 1-in-10 LOLE. On this basis, the 20% margin was deemed reasonable.[29] NB Power cited this conclusion in its 2024 Resource Adequacy Report as a justification for maintaining its 20% reserve margin provincially.[30]

The 2022 Maritimes Area Comprehensive Review of Resource Adequacy confirmed adequacy in the region through 2027 across multiple sensitivities (high load growth, 50% wind derate, and elimination of tie benefits). [31] NB Power's 2023 Integrated Resource Plan reached similar conclusions, finding that, though capacity deficits could materialize as early as 2026/2027 under

25 Transmission system operator responsibilities, tso.nbpower.com

26 2022 Maritimes Area Comprehensive Review of Resource Adequacy. NPCC. December 6, 2022. ("2022 Maritimes Comprehensive RA Review")

27 NERC defines the Reliability Coordinator as the entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.

28 *See* 2022 Maritimes Comprehensive RA Review.

29 *Id.*

30 Resource Adequacy Report. New Brunswick Power. March 18, 2024

31 *See* 2022 Maritimes Comprehensive RA Review.

high-electrification pathways, there was limited need for firm capacity before 2030 under baseline load growth assumptions.[32]

Since then, however, new uncertainties have emerged, including higher load forecasts, planned maintenance outages at hydro facilities, shifts in external capacity transactions, and delays in previously planned projects. The 2024 Maritimes Area Interim Review of Resource Adequacy projected that with 300 MW of assumed tie-line benefits, the system will no longer satisfy the 1-in-10 LOLE by 2028. At least 175 MW of incremental capacity or equivalent imports will be required, with needs increasing to 400 MW under high electrification scenarios. [33]

Additional regional studies reinforce this outlook. The 2024 NPCC Intermediate Area Transmission Review projects reserve margins declining from over 20% in 2026 to around 8% in 2029, with N-1-1 contingency analyses identifying southeastern New Brunswick as a reliability-critical subregion requiring roughly 200 MW of additional local supply.[34] Additionally, though the 2024 NERC Long-Term Reliability Assessment classifies the Maritimes as a “normal risk” region under average conditions, it notes potential shortfalls during extreme winter events, particularly given dependence on firm imports. It also highlights the risk of reserve margins collapsing to 3.9% by 2029 due to announced retirements.

Collectively, these analyses underscore a narrowing reliability margin across the Maritimes Area system and highlight the potential for adequacy shortfalls later this decade.[35] These conclusions, however, are dependent on underlying assumptions regarding demand growth, resource additions and retirements, and the availability of imports. In the following section, we review demand and supply forecasts from a range of sources and construct scenarios to test the persistence of these findings. This approach provides an independent check on the adequacy outlook and allows us to assess whether the reserve margin constraints identified in prior studies remain valid under alternative assumptions.

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32 2023 Integrated Resource Plan: Pathways to a Net-Zero Electricity System. NB Power. 2023.

33 *See* 2024 Maritimes Interim RA Review.

34 2024 NPCC Intermediate Area Transmission Review: Assessment of the Maritimes Area Bulk Power System for the Year 2029 (New Brunswick Portion). March 2025.

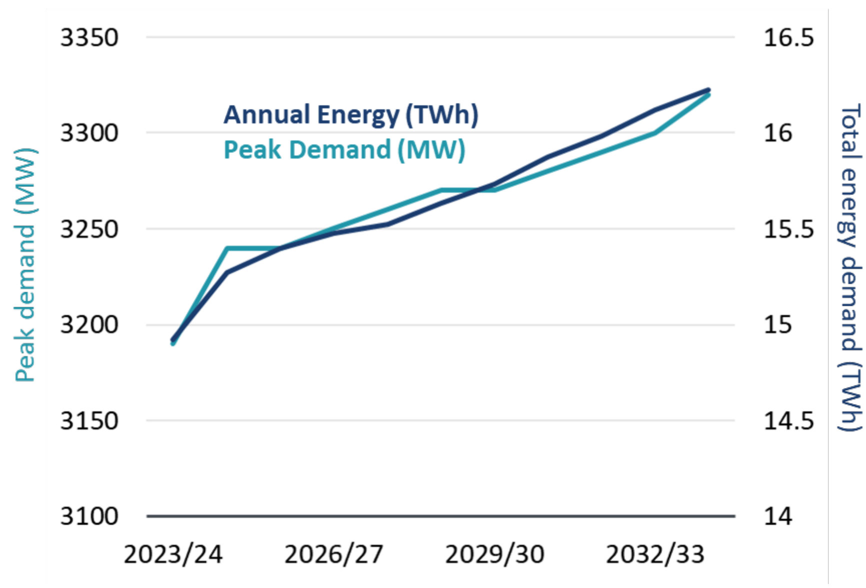
35 To complicate this issue, power generally cannot be stored at a massive amount and requires capacity to serve instantaneously all that is demanded. And this capacity requires several years to develop. This is why the investment timeline for the infrastructure-heavy power industry requires planners to 1) start building now what you expect to need by the end of the 5 years, or be contracted with others to do so, 2) finalize plans now for what you hope to build or contract in 5 to 10 years, and 3) plan for the period beyond 10 years, but recognize the uncertainties in those plans.

Electricity Demand Outlook for New Brunswick

To assess the robustness of previous reports' findings, we begin by reviewing available demand forecasts that underpin reliability assessments in New Brunswick.

NB Power operates as a winter-peaking utility, and annual peak demand typically materializes in January or February, coinciding with the coldest winter conditions. NB Power is projecting modest load growth through the middle of the 2030s, with overall electricity consumption growing by 1,304 GWh (9%) from 2023/2024 to 2033/2034 and peak demand growing by 130 MW (4%) over that same period (Figure 2). Average annual peak growth rate (0.4%) is slightly lower than the prior 20-year average (0.5%) due to increased gross demand (1.2% annually) being largely offset by Demand-Side Management (DSM) programs.

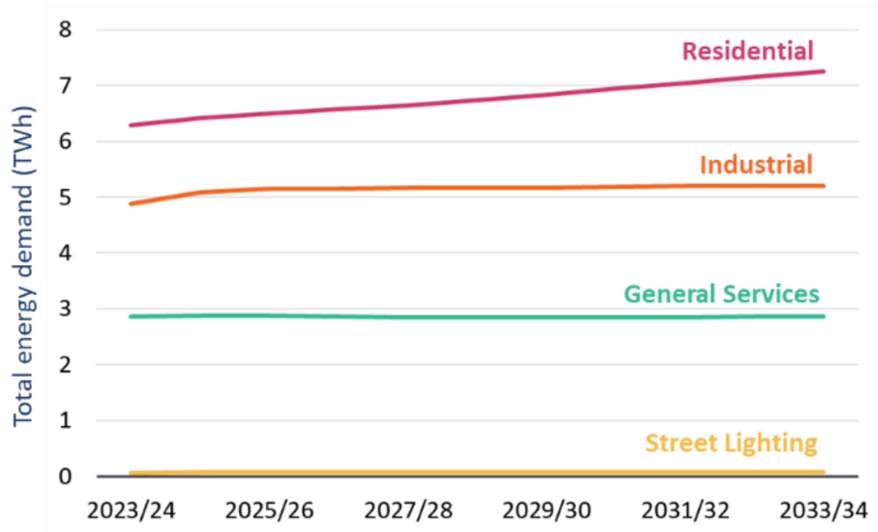
FIGURE 2: NEW BRUNSWICK TOTAL ENERGY AND PEAK DEMAND FROM 2023/24 THROUGH 2033/34



Drivers of Demand

Drivers of demand growth in NB Power's operating region include population growth, continued electrification of space heating, GDP growth (which drives commercial and industrial expansion), increasing adoption of electric vehicles (EVs), and electrification of certain industrial processes. These factors influence demand differently across sectors. Figure 3 shows the projected energy consumption by sector for New Brunswick.

FIGURE 3: NEW BRUNSWICK ENERGY SALES BY SECTOR FROM 2023/2024 THROUGH 2033/2034[36]



In the residential sector, population growth, continued electrification of space heating, and EV adoption are the main drivers of demand increases. By the 2033/2034 delivery period, the adult population of New Brunswick is projected to increase by approximately 73,900, representing an average annual growth rate of 1.1%. This demographic shift translates into roughly 45,500 additional year-round customers. At the same time, the saturation of households using electric heating is continuing to rise, increasing in recent years from 67% of households in 2018 to 75% in 2022. It is assumed that approximately 5.6% of households with non-electric heating will continue converting to electric each year moving forward. Finally, EV adoption is expected to grow substantially over this period, increasing residential sector demand by approximately 500 GWh by 2033/2034.

Both Gross Domestic Product (GDP) growth and EV adoption contribute to load growth in the general services sector, which accounts for both commercial (70%) and institutional (30%) sales. GDP is expected to increase at a rate of approximately 1.2% annually while growth in commercial EVs is expected to increase general services sector demand by approximately 350 GWh by 2033/2034.

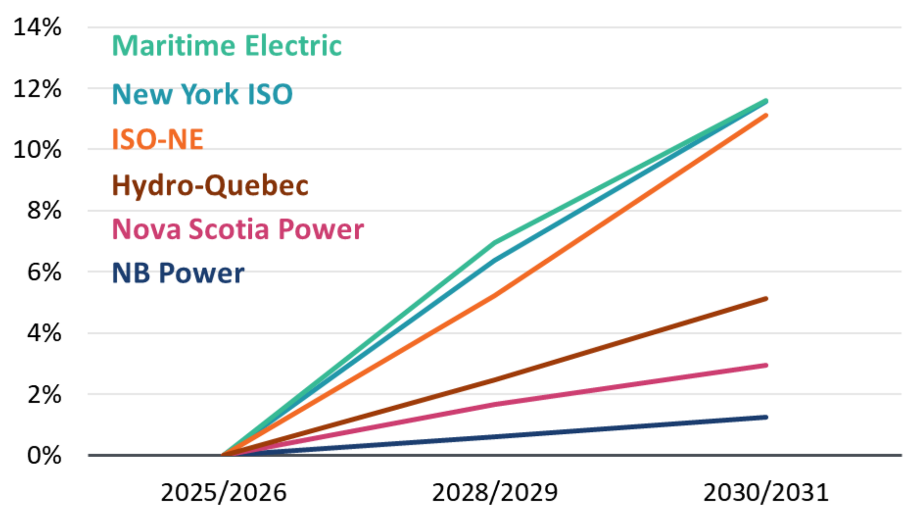
Industrial demand, which comprised 36 percent of total in-province sales in 2022/2023, is projected to rise over the 2023/2023 – 2033/2034 forecast period due to a combination of new entrants (e.g., Chief Fuels Inc.), incremental load from small industrial customers, and electrification of certain industrial processes.

36 Load Forecast 2024-2034. New Brunswick Power. November 2023.

Counterbalancing these growth drivers are the province's DSM and distributed generation initiatives. For all sectors combined (residential, general service, and industrial), DSM programs, including efficiency measures, conservation initiatives, demand shifting enabled by smart grid technologies, and advanced metering infrastructure, are expected to reduce consumption by 1,271 GWh and peak demand by 238 MW by 2033/2034.[37] Distributed generation is expected to reduce bulk power system demand by an additional 350 GWh by 2033/2034.

The key assumptions underlying this forecast, population growth, electrification initiatives, and economic activity, are summarized in Table 1. NB Power's economic base assumptions (population and GDP growth) are comparable with regional and national trends and, thereby, appear reasonable. While EV adoption assumptions are somewhat higher than Canadian averages, New Brunswick's overall load growth projection remains the lowest among neighboring regions (Figure 4). This reflects the fact that, as of 2022, about 75% of households in New Brunswick already used electric space heating, meaning a large portion of electrification is already captured in the existing load profile, moderating future growth relative to regions such as New England, New York, and Prince Edward Island, which anticipate higher rates of fuel-switching in the coming decade.

FIGURE 4: PEAK DEMAND GROWTH OF NEW BRUNSWICK AND NEIGHBORING REGIONS[38]



[37] 375 GWh from the residential sector, 484 GWh from the General Services sector, 309 GWh from the industrial sector, 103 GWh in avoided T&D losses. Source: NB Power Load Forecast 2024-2034. November 2023

[38] Prince Edward Island Resource Planning and Maritime Electric Capital Expenditures: Alternatives to MECL Integrated System Plans and Impact on MECL Capital Expenditures. Prepared for the PEI Regulatory and Appeals Commission. April 2022.; 2024 Load & Capacity Data Report (Gold Book). New York Independent System Operator. April 2024.; Load Forecast 2024-2034. New Brunswick Power. November 2023.; 2025 Forecast Data. From the 2025 CELT Report (2025-2045). ISO New England. May 2025.; Overview of Hydro-Québec's Energy Resources. Hydro-Québec. 2022.; 2025 10-Year System Outlook. NS Power. July 2025.

TABLE 1: KEY ASSUMPTIONS UNDERLYING NB LOAD GROWTH FORECASTS

Load Growth Factor	NB Assumption[39]	Other Regions Assumptions
Population Growth	+1.1%/year. Translates to 4,546 additional residential customers/year.	-0.9% in Québec[40] to +3.6% in Prince Edward Island.[41]
GDP	+1.2%/year, on average through 2033/2034	1.6% in Québec to 2.2%[42] in Prince Edward Island [43]
Emerging Large Loads	Data centers (e.g., Chief Fuels).	Hydro-Québec: data centers, green hydrogen production.[44] Nova Scotia: Hydrogen production.[45]
Electric Vehicles	2,762 EVs in 2023 growing to 211,200 EVs (76x) by 2033/34.	Approximately 910,000 EVs in Canada in 2025[46] growing to 14.4 million EVs by 2030 (12x).[47] Approximately 400,00 EVs in Québec in 2025[48] growing to 3.5 million EVs by 2035 (9x).[49] Approximately 9,000 EVs in Nova Scotia in 2025[50] growing to 100,000 by 2034 (11x).[51]
Electric Space Heating	75% of New Brunswick households use electricity for space heating. About 5.6% of non-electric households assumed to convert to electric heating per year.	Prince Edward Island electric space heating increased from 36% of households in 2018 to 45% of households in 2022.[52] Approximately 80% of Quebec households use electric space heating.[53] Nova Scotia electric space heating increased from 46% of households in 2018 to 50% of households in 2022.[54] ISO-NE anticipating 58% of housing stock to electrify space heating by 2050.[55]

Taken together, these dynamics point to a relatively moderate and stable long-term load trajectory. Growth in population, EV adoption, and industrial activity provides upward momentum, while the already highly electrified heating systems and aggressive DSM initiatives constrain the rate of increase.

Forecast Sensitivities and Sources of Uncertainty

Weather conditions and demographic trends are two key drivers impacting electricity consumption in New Brunswick. Historical analysis shows that demographic variations, when combined with weather sensitivities, have been responsible for much of the divergence between forecasted and realized peak demands in the past decade.[56]

Since New Brunswick has a high penetration of electric space heating, small deviations in temperature or customer growth lead to large swings in peak demand. Cold winters have consistently driven measurable increases in peak load, with extreme weather events pushing load well beyond what was projected under reference case assumptions. For example, winter

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39 Load Forecast 2024-2034. New Brunswick Power. November 2023.

40 Population projections up to 2051 revised downward for Québec and its regions. Institut de la statistique du Québec. July 30, 2025.

41 Prince Edward Island Population Projections 2023 – 2062. Prince Edward Island Statistics Bureau. 2023.

42 Provincial Economies are Turning the Tide. The Conference Board of Canada, republished online at rss.globenewswire.com. August 19, 2024.

43 State Economic Forecast Webpage. TD Economics, TD Bank website. September 23, 2025. Last accessed October 30, 2025.

44 Overview of Hydro-Québec's Energy Resources. Hydro-Quebec. October 2022.

45 2025 10-Year System Outlook. NS Power. July 2025.

46 ZEV Council Dashboard. Government of Canada. April 2025.

47 Updated forecasts of vehicle charging needs, grid impacts and costs for all vehicle segments. Natural Resources Canada. February 2024.

48 ZEV Council Dashboard. Government of Canada. April 2025.

49 How does your electric vehicle affect your electricity bill? Hydro-Québec. Last accessed October 27, 2025.

50 ZEV Council Dashboard. Government of Canada. April 2025.

51 Nova Scotia Power IRP Final Report Appendices A-N. 2020.

52 Natural Resources Canada's National Energy Use Database, Residential Sector – Prince Edward Island, Table 21.

53 Overview of Hydro-Québec's Energy Resources. Hydro-Québec. October 2022.

54 Natural Resources Canada's National Energy Use Database, Residential Sector – Nova Scotia, Table 21.

55 Final 2025 Heat Pump Forecast. ISO-NE. May 1, 2025.

56 Load Forecast 2024-2034. New Brunswick Power. November 2023.

peak demand has historically moved by as much as 30 MW for each one-degree Celsius change in the eight-hour weighted average temperature leading up to the system peak.[57]

Customer and population growth (demographic trends) provide a second source of forecast variance. NB Power assumes that, on average, each additional 1,000 customers translates to roughly 10 MW of incremental peak demand.[58] NB Power assumes an average annual growth of 4,546 new residential customers, based on historical regressions and the assumption that future looking years' population growth rates hold steady.[59]

General long-term effects of weather and demographic trend uncertainty are incorporated into NB Power's forecasting methodology through probabilistic econometric modeling, which captures a plausible range of peak demand outcomes under more moderate (P90) and more extreme (P10) assumptions.[60] Considering P90 and P10, load forecasts for the 2024/2025 to 2033/2034 period varies by +565 MW (under P10) to -484 MW (for P90), relative to the reference (P50) forecast.

However, forecast variance can occur beyond the P90 and P10 thresholds, driven by extreme temperature conditions and rapid shifts in population growth. For example, in the 2023/2024 fiscal year, NB added approximately 7,000 new year-round residential customers, which is more than 50% higher than the average annual additions projected from 2024/25 to 2033/34 (approximately 4,550).[61] Additionally, an extreme cold event on February 4, 2023, where temperatures were on average six degrees Celsius below the forecast assumption of –22 degree Celsius, resulted in NB Power setting a new hourly peak record of 3,392 MW, which was 362 MW above the forecast peak for that year.[62]

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[57] Resource Adequacy Report. New Brunswick Power. March 18, 2024.

[58] Load Forecast 2024-2034. New Brunswick Power. November 2023.

[59] *Id.*

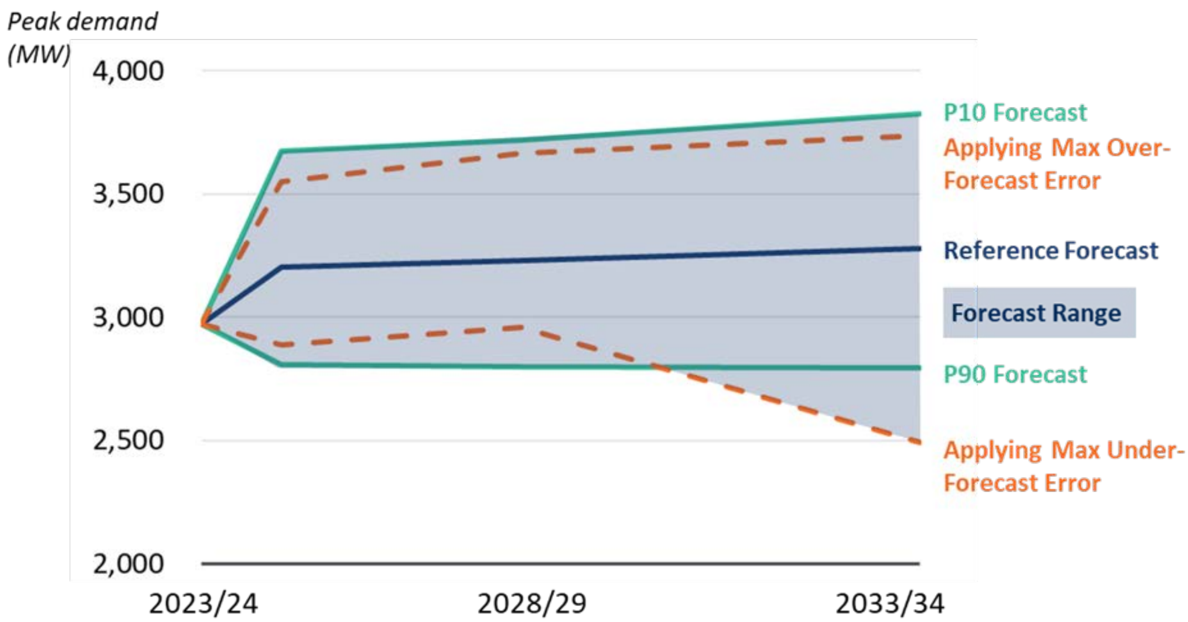
[60] A PXX load forecast refers to probabilistic demand projections that express uncertainty around the baseline (P50, or "most likely") forecast. A P10 forecast represents a "high load" case, where there is only a 10% probability that actual demand will exceed that level (i.e., demand is lower than this level in 90% of cases). Conversely, a P90 forecast represents a "low load" case, where there is a 90% probability that demand will exceed that level (i.e., demand is lower in than this level in only 10% of cases). These forecasts are often used in reliability and resource adequacy studies to test system performance under more extreme but plausible demand outcomes.

[61] Load Forecast 2024-2034. New Brunswick Power. November 2023. Not all 7000 customers were connected to NB Power. Some were indirect/wholesale residential customer additions from Saint John Energy and Edmundston Energy service territories.

[62] This impact is roughly double that of the 30 MW per one degree Celsius observed.

Figure 5 illustrates a plausible range of future peak demand, combining both P90 and P10 statistical forecast bounds, as well as historically observed forecast variance. Overlaying probabilistic ranges (which capture projected variations) with the empirical record of variance (which captures actual deviations), produces a forecast band that more realistically reflects the range of outcomes the system may encounter. Using a dual lens ensures that the forecast range is both statistically grounded and empirically validated. Importantly, this approach shows how uncertainty compounds over time: the variance envelope widens further into the forecast horizon, reflecting both greater demographic and weather uncertainty.

FIGURE 5: PEAK LOAD FORECAST RANGE[63]



Beyond the established drivers of population growth (which leads to customer additions), and baseline weather sensitivity, the range of uncertainty in New Brunswick's load outlook is expected to widen considerably as new electrification and industrial trends emerge. Several factors contribute to this expansion, each adding distinct layers of potential volatility.

Transportation electrification represents one of the most immediate sources of uncertainty. While the baseline forecast incorporates a medium-adoption scenario for EVs, actual uptake could be faster or slower depending on consumer behavior, policy support, and charging

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[63] 10-Year Plan Fiscal Years 2021-2030. NB Power. September 2019; Load Forecast 2024-2034. New Brunswick Power. November 2023.

infrastructure deployment.[64] Under an accelerated adoption path, electricity demand could rise by an additional 170 GWh by 2033/2034, with peak demand increasing by approximately 10 MW. Conversely, slower adoption would dampen demand relative to the reference case.

Industrial activity is another area of uncertainty. Data centers are highly energy-intensive, yet the timing and scale of potential projects in New Brunswick remain unknown. The impact of a single large industrial customer could be significant: entry or exit of one facility consuming 375 GWh annually could alter system requirements by roughly ±50 MW at peak.[65] More broadly, commercial and industrial decarbonization efforts may accelerate the electrification of processes currently reliant on fossil fuels. Should these transitions proceed more rapidly than anticipated, system demand could exceed planning expectations, heightening the risk of capacity shortfalls.

Finally, macroeconomic conditions remain a structural driver of load. A 0.5% change in provincial GDP growth is estimated to shift commercial and industrial sales by roughly ±150 GWh, with corresponding impacts of ±10 MW on peak demand.[66] Given the province's economic integration with broader regional and national trends, and underlying assumptions of GDP growth being lower than neighboring regions (see Table 1), such deviations are plausible over the forecast horizon.

Table 2 summarizes these forecast sensitivities, quantifying the potential impacts of alternative scenarios across transportation, industrial development, weather, demographic growth, and macroeconomic performance. Together, these assumptions underscore the breadth of possible outcomes and highlight the need for flexible resource portfolios and robust reliability planning to manage uncertainty in New Brunswick's future load trajectory.

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[64] As an example, the federal government recently paused EV rebates leading to a sharp drop in new registrations.

[65] Load Forecast 2024-2034. New Brunswick Power. November 2023.

[66] *Id.*

TABLE 2: FORECAST SENSITIVITIES[67]

Driver of Uncertainty	Assumption / Sensitivity	Impact on Annual Energy (GWh)	Impact on Peak Demand (MW)	Notes
Transportation Electrification (EV Adoption)	Faster/slower adoption sensitivities tested	±170 GWh by 2033/2034	±10 MW by 2033/2034	Includes personal, commercial light-duty, medium-duty, heavy-duty, and bus fleets
Data Centers / Large Industrial Customers	Entry/exit of a 375 GWh customer	±375 GWh annually	±50 MW	Assumes annual load comparable to a large industrial facility
Commercial & Industrial Decarbonization	Accelerated electrification of processes	Not quantified separately	Potentially material increases	Represents structural shift from fossil fuels to electricity
Extreme Weather (Temperature Sensitivity)	1°C deviation in 8-hr weighted average at peak	N/A	±30 MW	Historical record shows extreme cold can add 300–400 MW in a single year[68]
Demographic Growth (Population / Customers)	Baseline assumption: +95,000 people (1.1%/yr); Sensitivity: ±1000 year-round customers by 2033/2034	±14–20 GWh	±10 MW by 2033/2034	Based on NB provincial population projections (Jan 2023)
Macroeconomic Conditions (GDP Growth)	±0.5% change in provincial real GDP	±150 GWh	±10 MW	Primarily affects commercial & industrial sectors

67 *Id.*

68 *Id.*

In summary, New Brunswick's future load trajectory is subject to a wide band of uncertainty. For NB Power, this reinforces the need for flexible resources, robust reserve margins, and scenario-based planning to ensure that reliability standards are met under both expected and extreme conditions.

NEW BRUNSWICK'S SUPPLY OUTLOOK

Factors Affecting New Brunswick Supply

To complement the demand-side analysis, we next review available supply forecasts, including committed resources, planned retirements, and prospective additions, to assess the extent to which New Brunswick's future resource portfolio can meet projected reliability requirements.

The Maritimes Area, including New Brunswick, is entering a period of profound transition for its electricity supply, shaped by federal climate policy, aging infrastructure, renewable integration, and the potential introduction of new technologies. Together, these forces will redefine the province's generation mix over the next two decades, requiring careful planning to maintain reliability while advancing toward net-zero objectives. Across planning documents, firm generation capacity in the near-term (through 2030) is projected in the range of 3,768 to 3,823 MW, depending on assumptions for Belledune's conversion and the Mactaquac Life Achievement Project (see Table 3).

TABLE 3: SUMMARY OF SUPPLY CAPABILITY IN THE NEAR-TERM (THROUGH 2030)[69]

Source	Firm Generation Capacity	Notes
NPCC 2024 Intermediate Area Transmission Review	3,823 MW (not including wind)	Belledune biomass conversion derating (115 MW). MLAP.
NB Power 2023 Integrated Resource Plan NB Power 2024 Resource Adequacy Report	3,768 MW (not including wind)	Belledune biomass conversion derating (92 MW). MLAP.

[69] 2024 NPCC Intermediate Area Transmission Review: Assessment of the Maritimes Area Bulk Power System for the Year 2029 (New Brunswick Portion). March 2025; 2023 Integrated Resource Plan: Pathways to a Net-Zero Electricity System. NB Power. 2023.; Resource Adequacy Report. NB Power. March 2024.

Climate Policy and the Future of Belledune

Federal regulations mandating the phase-out of coal-fired generation by 2030 will directly affect NB Power's largest fossil unit, the Belledune Generating Station. Originally slated to retire in 2040, Belledune must now cease coal burning a decade earlier. NB Power is actively exploring conversion pathways that would allow continued operation using alternative fuels. Options under study include traditional and torrefied biomass, renewable natural gas, conventional natural gas, and liquefied natural gas.

In March 2024, Belledune conducted test burns using advanced wood pellets (biomass). The station successfully completed two full operations at 100% advanced pellet fuel, demonstrating the technical feasibility of biomass conversion. While promising, NB Power does not expect a full transition before 2030. [70] If successful, biomass conversion is expected to preserve approximately 375 MW of Belledune's 467 MW of capacity beyond the coal phase-out date.

The Mactaquac Life Achievement Project

Another critical supply resource is the Mactaquac Generating Station, a 672 MW hydroelectric facility commissioned in 1968. Today, Mactaquac supplies roughly 12 percent of the province's electricity and remains the largest hydroelectric station operated by NB Power.[71] However, since the 1980s the plant has faced significant structural challenges caused by alkali–aggregate reaction (AAR), a chemical process in which alkalis in cement react with silica in the aggregate. The result is expansion of the concrete, leading to cracking, seepage, and long-term deterioration of key structures.

Without intervention, these effects would reduce the facility's service life from its original 100-year design to approximately 60 years, indicating end of life by around 2030. [72] Analysis in NB Power's 2023 IRP demonstrated that retiring Mactaquac in 2030 and replacing it with alternative resources to provide equivalent energy, capacity, and ancillary services would drive costs sharply higher.[73]

NB Power's proposed Mactaquac Life Achievement Project (MLAP) is designed to ensure continued operation through 2068. This initiative involves a modified maintenance regime and targeted equipment replacement to manage the impacts of AAR. Between 2027 and 2033, each

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70 Belledune Clean Fuel Project. NB Power.

71 2023 Integrated Resource Plan: Pathways to a Net-Zero Electricity System. NB Power. 2023.

72 *Id.*

73 *Id.*

of the six generating units will be taken offline for approximately 16 months, with only one unit (112 MW) reduced during winter seasons to maintain system reliability. [74] [75]

Near-term Investments and Life Extensions

NB Power anticipates little near-term capacity investment beyond the RIGS project. The 2023 IRP noted that approximately 300 MW to 500 MW of new wind capacity could come online by 2026/27. Additionally, a handful of diesel generators—Grand Manan (26 MW), Millbank (397 MW), and St. Rose (99 MW)—that were previously scheduled to retire in 2030/31 have been approved for life extensions to maintain system reliability during the projected near-term supply deficit.

Supply Balance and System Outlook

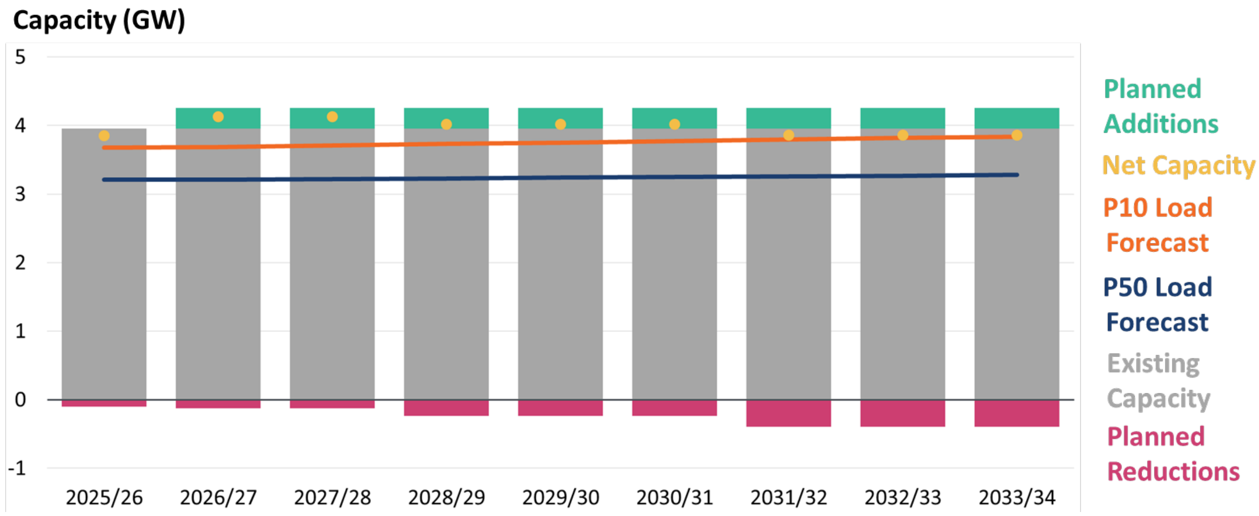
The net effect of these changes is a shifting supply balance over the coming decades. Figure 6 outlines these changes. In the near term (through the mid-2030s), approximately 300 MW of new wind capacity may come online while the MLAP refurbishment work progresses.[76] However, the mandated coal phase-out will create a major supply gap that must be filled through a combination of renewables, imports, new capacity additions, and potentially Belledune biomass conversion.

74 Mactaquac Life Achievement Project. NB Power.

75 NB Power plans to use the RIGS investment, in part, to balance the temporary capacity reductions and ensure that system reliability is not compromised during this refurbishment period.

76 2023 Integrated Resource Plan: Pathways to a Net-Zero Electricity System. NB Power. 2023.

FIGURE 6: NEW BRUNSWICK'S SUPPLY OUTLOOK[77]



Supply Uncertainties and Risks

While demand growth in New Brunswick is shaped by demographic and economic drivers, supply-side risks arise largely from operational contingencies, resource availability, and technology transitions. NB Power incorporates these uncertainties into both operational practices and long-term planning to ensure that reliability standards are met under a range of potential outcomes.

Looking ahead, several factors are expected to heighten uncertainty on the supply side, which are summarized in Table 4 below.

- **Variable Renewable Output:** Increasing reliance on wind and solar introduces planning and operational challenges, particularly during peak events. In extreme cold, when demand spikes, some wind generation may cut out entirely below –30 degrees Celsius. High winds or operational restrictions can also force turbines offline. These risks constrain the capacity value of renewables during critical peak periods.[78]
- **Mactaquac Project Delay Risks:** MLAP requires staged outages between 2027 and 2033, with each unit removed for about 16 months. Planning ensures no more than one unit is

[77] Major assumptions in this figure: Bayside Gas Turbine Extension beyond 2038. Belledune conversion to biomass. Addition of SMRs in the mid-late 2030s. Addition of 300 MW of wind in the late 2020s. Extension of most PPAs through 2050 (i.e. Grandview, St. George, Twin River, etc.).

[78] In addition, the variable output of the renewables could increase the operating reserve requirements. For example, the National Renewable Energy Laboratory (NREL) provides as a proxy that every MWh of wind could require 0.5% increase in regulation and 10% increase in flexible reserves. Similarly, NREL assumes every MW (capacity) of solar could require 0.3% increase in regulation and 4% increase in flexible reserves.

offline in winter, but delays could result in two concurrent outages, further reducing available capacity by 112 MW during peak periods.

- **Point Lepreau Nuclear Performance:** While central to the system, PLNG's reliability has varied. The 2022 Comprehensive Maritimes Area Resource Adequacy Review assumed a 5.5% forced outage rate. However, recent operating experience indicates higher forced outage rates for PLNGS.[79] This higher outage rate assumption reduces effective capacity by about 60 MW.
- **Belledune Fuel Transition:** Conversion of Belledune from coal to biomass by 2030 introduces uncertainty. Although advanced biomass pellet tests have been successful, the long-term impact on unit capacity and availability is not yet confirmed, and there is risk that an unsuccessful fuel transition will put Belledune out-of-service by 2030.

TABLE 4: POTENTIAL SUPPLY RISKS[80]

Risk Timeline (MW)	2025	2026	2027	2028	2029	2030
Mactaquac Project Delays					-112	-112
Reduced Lepreau Performance	-60	-60	-60	-60	-60	-60
Unsuccessful Belledune Fuel Transition						-375
Temperature-driven Wind Outage	-162	-162	-162	-162	-162	-162
Total	**-222**	**-222**	**-222**	**-222**	**-334**	**-709**

In summary, New Brunswick's supply outlook reflects both planned investments and material sources of risk. Firm capacity over the next decade is projected to remain in the range of 3,768 MW to 3,823 MW, but this balance is highly sensitive to the timing of coal phase-out, the success of Belledune's fuel conversion, the execution of MLAP, and the performance of the aging nuclear and thermal asset fleet. Collectively, these dynamics suggest that while the resource portfolio may appear adequate under reference conditions, deviations in project timing, technology performance, or extreme weather could create meaningful capacity shortfalls.

79 In NB Power's 2024/25–2025/26 General Rate Application (Matter 552), NB Power presented multiple data points supporting forced outage rate values in the 7–8% range, including: an 8.4% five-year average (FY2019–2023), an 8.3% five-year average (FY2020–2024), a 7.0% six-year average (FY2019–2024), and a 7.8% rate based on post-refurbishment performance (see Matter 552, Testimony of Mr. Church, Transcript pp. 2635, 2639; Testimony of Mr. Nouwens, Transcript p. 2696; Exhibits NBP 17.02 and NBP 17.03).

80 Resource Adequacy Report. NB Power. March 2024.

For this reason, it is essential to test whether the combination of forecast demand and projected supply can sustain reliability standards under a range of conditions. In the next section, we construct scenarios that overlay demand and supply trajectories to assess the robustness of reserve margins. This analysis provides an independent validation of adequacy risks and clarifies whether the tightening conditions identified in prior assessments remain valid under alternative assumptions.

Planning Reserve- and Operational Requirements-based Scenario Analysis

With demand and supply trajectories established, we now undertake an integrated scenario analysis, stress-testing the system under varying assumptions for load growth, resource availability, and capacity deratings to quantify reliability risk over the planning horizon. This analysis evaluates reliability risk based on 1) operational requirements (short-term adequacy under contingency conditions) and 2) planning reserves (longer-term adequacy under evolving demand assumptions). For the operational requirements-based analysis, we focus on supply-side risks and uncertainties, including system contingencies, project delays, and temperature-related wind generation outages. For the planning reserve-based analysis, we assess longer-term demand-side risks such as weather-driven increases in peak demand, higher-than-expected growth in the residential and commercial sectors, and accelerated electrification trends. Consistent with NB Power planning and operational procedures, we assume that NB Power must carry capacity to cover their largest contingency (PLNGS) in the operational requirements-based analysis, and a 20% reserve margin in the planning reserve-based analysis.[81] We also assume that current firm export obligations continue throughout the scenario evaluation period. Other scenario assumptions are anchored in NB Power's planning documents and load forecasts and are designed to test how key uncertainties influence system reliability outcomes.

Operational Requirement-based Scenarios

Based on historical observations, NB Power applies a forced outage rate assumption of 200 MW across the fleet in its annual and 18-month adequacy assessments.[82] For variable generation,

[81] We understand that recent analyses show that simply maintaining the 20% reserve margin may not be enough to satisfy the NPCC LOLE criteria. Therefore, these calculations are more for illustrative purposes in evaluating the needs NB Power is facing.

[82] NP Power assumes 200 MW forced outages to reflect a 5% forced outage rate applied to its total installed firm generation capacity. Brattle's independent review of plant capacity and forced outage rates finds approximately 270 MW of forced outages and deems the 200 MW assumption reasonable.

wind resources are credited with 136 MW of effective capacity, reflecting average availability from New Brunswick wind farms as well as imports from West Cape and Mars Hills.

To meet reliability standards, NB Power must also maintain substantial operating reserves. NERC requires contingency reserves equal to the system's Most Severe Single Contingency, typically the PLNGS at 715 MW. NPCC imposes additional requirements, including synchronized reserves and thirty-minute reserves equal to half of the second-largest contingency, often Belledune at 467 MW. Together, these obligations require roughly 948 MW of operating reserve capacity.

NB Power does participate in non-firm reserve sharing agreements totaling 468 MW: 200 MW with ISO-NE, 168 MW of ten-minute reserve and 50 MW of thirty-minute reserve with Nova Scotia Power, and 100 MW of load-as-reserve within its own distribution system. However, these reserves sharing agreements are non-firm and cannot be assumed reliable during regional stress events, since neighboring systems will likely be experiencing similar constraints. For this reason, reserve sharing is excluded from baseline adequacy assessments. To reflect a realistic range of outcomes, our scenario analysis includes a case where approximately half of this non-firm reserve sharing is available under emergency conditions.

Using these assumptions, three scenarios (outlined in Table 5) were modeled to capture a plausible range of risks associated with contingencies, unplanned outages, and demand variability:

- **Favorable Conditions Scenario.** Reflects the P90 peak load forecast, full activation of interruptible load programs, and contracted exports. The largest contingency is set at 715 MW (PLNGS), with no additional risks modeled for Mactaquac, Belledune, or wind resources. Unplanned outages are modeled at 200 MW. This scenario represents a best-case boundary condition under which incremental capacity would not be required.
- **Reference Conditions Scenario.** Reflects the reference P50 load forecast and applies the same operational assumptions as the Favorable Conditions Scenario.
- **Adverse Conditions Scenario.** Reflects a P10 peak load forecast and incorporates additional supply stressors, including extended outages at Mactaquac due to project delays, a reserve requirement equal to half of the second-largest contingency (233 MW in 2028 and 2029, 162 MW in 2030), [83] weather-driven wind outages, and an unsuccessful biomass conversion at Belledune, which would put the plant out of service. In this case, half of the non-firm reserve sharing is assumed available to simulate limited emergency support.

[83] Since our scenario assumes Belledune is out of service by 2030, we assume the second largest contingency would be one unit of Colesone Cove in that operating year.

TABLE 5: OPERATIONAL REQUIREMENT-BASED SCENARIO ASSUMPTIONS

	Favorable Conditions	Reference Conditions	Adverse Conditions
Peak Load Forecast	P90 load forecast	P50 load forecast	P10 load forecast
Interruptible Load Forecast	Same as 2024 RA Report	Same as 2024 RA Report	Same as 2024 RA Report
Largest Contingency Reserve	715 MW equivalent to Lepreau gross output	715 MW equivalent to Lepreau gross output	715 MW equivalent to Lepreau gross output
Export Load Capacity Contracts	Same as 2024 RA Report	Same as 2024 RA Report	Same as 2024 RA Report
Mactaquac Project Delays	No	No	Yes
2nd Largest Contingency Reserves	No	No	Yes
Temperature-Driven Wind Outage	No	No	Yes
Unsuccessful Belledune Fuel Transition	No	No	Yes
Standard Forced Outages	-200 MW	-200 MW	-200 MW
50% Reserve Sharing Availabliity	Assumed none needed.	+234 MW if net position is negative	+234 MW if net position is negative

Results (Table 6) show that operational shortfalls emerge in both the Reference and Adverse Conditions Scenarios. Under the Adverse Conditions Scenario, the net position declines from being short by 1,026 MW in 2028 to 1,574 MW in 2030, reflecting compounding effects of higher demand, additional contingencies, and reduced resource availability. The Reference Conditions Scenario shows persistent deficits of roughly 167 to 279 MW over the same period. Even under Favorable Conditions Scenario, the system fails to maintain adequate supply, with a modest surplus that narrows from the mid-2020s to a 73 MW shortfall by 2030, leaving no headroom.

TABLE 6: OPERATIONAL REQUIREMENTS-BASED SCENARIO OUTCOMES[84]

		Favorable Conditions			Reference Conditions			Adverse Conditions		
		2028	2029	2030	2028	2029	2030	2028	2029	2030
Peak Load Forecast	[1]	2790	2800	2800	3220	3230	3240	3710	3730	3750
Interruptible load forecast	[2]	-110	-110	-110	-110	-110	-110	-110	-110	-110
Largest contingency reserve	[3]	715	715	715	715	715	715	715	715	715
Export load capacity contracts	[4]	372	372	372	372	372	372	372	372	372
Mactaquac project delays	[5]	0	0	0	0	0	0	0	112	112
2nd largest contingency	[6]	0	0	0	0	0	0	233	233	162
Unsuccessful Belledune fuel transition	[7]	0	0	0	0	0	0	0	0	375
Forced outages	[8]	200	200	200	200	200	200	200	200	200
Total Requirement	[9]	3967	3977	3977	4397	4407	4417	5120	5252	5576
Total Resources Less Wind	[10]	3860	3860	3768	3860	3860	3768	3860	3860	3768
Wind	[11]	136	136	136	136	136	136	0	0	0
Total Resources	[12]	3996	3996	3904	3996	3996	3904	3860	3860	3768
Net Position (MW)	[13]	29	19	-73	-401	-411	-513	-1260	-1392	-1808
50% Reserve Sharing Availabliity	[14]	0	0	0	234	234	234	234	234	234
Net Position with RSA (MW)	[15]	29	19	-73	-167	-177	-279	-1026	-1158	-1574

[9] = [1] + [2] + [3]+ [4] + [5] + [6] + [7] + [8]
[12] =[10] + [11]
[13] = [12] - [9]
[14]: equivalent to second largest contingency
[15] = [13] + [14]

[84] Peak load assumption from NB Power Load Forecast Report 2024-2034, November 2023. Remaining assumptions from NB Power Resource Adequacy Report, March 18, 2024.

Planning Reserve-based Scenarios

While the operational requirement-based scenario analyses highlight short-term adequacy under contingency conditions and other supply-side risks, the planning reserve-based scenarios test whether the system can meet reliability standards given longer-term uncertainties in peak demand, driven by population growth, weather variability at peak, and rates of electrification. Three scenarios (outlined in Table 7) were modeled to reflect these uncertainties:

- **Favorable Conditions Scenario.** Assumes a peak load consistent with the P90 forecast, warmer temperatures at peak, lower-than-expected population and GDP growth, and modest electrification. Again, this reflects the conditions necessary for new capacity investment to not be needed.
- **Reference Conditions Scenario.** Reflects reference case (P50) load forecasts and standard assumptions for demand and resource availability.
- **Adverse Conditions Scenario.** Assumes a peak load consistent with the P10 forecast and incorporates additional demand uncertainties, including higher residential customer growth, additional commercial load, accelerated EV adoption, and more adverse winter weather conditions.

TABLE 7: PLANNING RESERVE-BASED SCENARIO ASSUMPTIONS

	Favorable Conditions	Reference Conditions	Adverse Conditions
Peak Load Forecast (2030)	P90 load forecast	P50 load forecast	P10 load forecast
Interruptible load forecast	Same as 2024 RA Report	Same as 2024 RA Report	Same as 2024 RA Report
20% Reserve margin	20% of peak load	20% of peak load	20% of peak load
Export load capacity Contracts	Same as 2024 RA Report	Same as 2024 RA Report	Same as 2024 RA Report
+/- temperature at peak	3 degrees warmer than forecasted	No	3 degrees colder than forecasted
+/- residential customers per year	-300 customers	No	+3200 additional customers
+/-% change in rate of GDP growth	-0.5% lower GDP growth than forecasted	No	+0.5% higher GDP growth than forecasted
Adoption rate of electric vehicles by 2033/34	Slower than base forecast assumptions	No	Faster than base forecast assumptions

Results (Table 8) show that in 2030 New Brunswick's Planning Reserve ranges from a surplus of +355 MW under the Favorable Conditions Scenario to a shortfall of 1,199 MW in the Adverse Conditions Scenario. Under the Reference Conditions Scenario, a projected supply deficit of 308 MW indicates that the system fails to meet NPCC planning reserve standards, even under modest demand and supply assumptions.

TABLE 8: PLANNING RESERVE-BASED SCENARIO OUTCOMES[85]

		Favorable Conditions (MW)	Reference Conditions (MW)	Adverse Conditions (MW)
Peak Load Forecast	[1]	2800	3240	3750
Interruptible load forecast	[2]	-110	-110	-110
Export load capacity Contracts	[3]	402	402	402
± temperature at peak	[4]	-90	0	180
± residential customers	[5]	-3	0	32
0.5 % change in rate of GDP growth	[6]	-10	0	10
Faster/slower adoption of electric vehicles	[7]	-10	0	10
Total Peak Demand	[8]	2979	3532	4274
20% Reserve margin	[9]	596	706	855
Total Requirement	[10]	3575	4238	5129
Total Resources Less Wind	[11]	3768	3768	3768
Wind	[12]	162	162	162
Total Resources	[13]	3930	3930	3930
Net Position (MW)	[14]	355	-308	-1199

[8] = [1] + [2] + [3]+ [4] + [5] + [6] + [7]
*[9] = [8] * 0.20*
[10] = [8] + [9]
[13] =[11] + [12]
[14] = [13] - [10]

Conclusions: Imminent Need for Capacity

The combined results of the operational requirement-based and planning reserve-based scenario analyses reveal a clear and concerning trend: New Brunswick's reserve margin is eroding rapidly and, under most plausible future conditions, will soon fall below the levels required to reliably meet demand in accordance with industry standards and NPCC reliability requirements.

By 2028, the province faces growing risks of operational shortfalls (182 MW under the Reference Conditions Scenario and 1,026 MW under the Adverse Conditions Scenario) and by 2030, even the most optimistic Favorable Conditions Scenario shows a 73 MW deficit, eliminating any remaining operational surplus. The planning reserve assessment reinforces this finding: while the Favorable Conditions Scenario shows a modest 355 MW surplus by 2030, both the Reference and Adverse Conditions Scenarios indicate significant shortfalls of 308 MW and 1,199 MW, respectively.

85 Peak load assumption from NB Power Load Forecast Report 2024-2034, November 2023. Remaining assumptions from NB Power Resource Adequacy Report, March 18, 2024.

Importantly, the Favorable Conditions Scenario should not be interpreted as a realistic planning benchmark. It is based on a P90 load forecast, which assumes only a 10% probability that actual load will be at or below this level and does not account for the compounding risks of outages, deratings, and weather-driven variability that more accurately reflect system adequacy under realistic conditions. While this scenario is informative in illustrating circumstances under which new investment might appear unnecessary, it does not provide a prudent basis for reliability planning. By contrast, New Brunswick has adopted a P10 load forecast, consistent with the assumptions underlying the Adverse Conditions Scenario, in its more recent NBEUB reliability planning filings.[86] Accordingly, greater weight should be placed on the Adverse Conditions Scenario results, which show capacity deficits, rather than on the overly optimistic Favorable Conditions Scenario outcomes.

In sum, the analysis confirms that reliability risks in New Brunswick are imminent, material, and worsening. To maintain established reliability standards and guard against adverse conditions, at least 300–400 MW of new firm capacity is required. Given that these shortfalls are projected to emerge before the end of the decade—and recognizing the long lead times for major generation projects—immediate action is needed to secure new capacity.

However, a critical question remains: should this additional capacity be developed within the province or obtained through firm import arrangements? The following section explores New Brunswick’s current and potential import capabilities to inform this decision.

[86] Matter EL-001-2025, Exhibit NBP 9.01 NBEUB IR-05; PJM and ISO-New England also use P10 in their long-term reliability planning procedures.

IV. Alternative to RIGS

The previous Section analyzed how procuring at least 300 MW to 400 MW of new firm capacity is a prudent hedge against the future load growth and changing resource portfolio. We now turn to an assessment of New Brunswick's import capability, evaluating the extent to which firm imports could substitute for or complement the new in-province resource development of RIGS.

A Review of Transmission in New Brunswick

Existing Transmission Capability

New Brunswick's transmission system functions as the central hub of the Maritimes Area, interconnecting with Hydro Québec (HQ), ISO New England (ISO-NE), the Northern Maine Independent System Administrator (NMISA), Nova Scotia Power, and Maritime Electric (serving Prince Edward Island). Collectively, these ties provide up to 2,448 MW of transfer capability into New Brunswick, facilitating electricity flows across Atlantic Canada and into neighboring markets.[87] While these ties provide regional connectivity, each interface is subject to distinct thermal, voltage, and stability constraints that limit ability to import any of this as firm power. New Brunswick's annual imports (approximately 6 TWh) are mainly from Hydro Québec and ISO-NE, while exports (approximately 5 TWh) go to Nova Scotia Power, Maritimes Electric, and NMISA. [88] All imports into the region are a result of non-firm energy purchases or wheeling agreements from Hydro-Québec to ISO-NE. Exports include firm agreements to other Maritimes Area utilities (Maritime Electric and NMISA) and economic transactions with ISO-NE and Hydro-Québec.[89]

Nova Scotia Power

NB Power's interface with Nova Scotia Power is made up a single 345 kV AC and two 138 kV AC lines. The interface is limited to 350 MW of import capability into New Brunswick to maintain stability and thermal limits in Nova Scotia in the event of loss of the single tie line between the two systems. The single-contingency nature of this line limits the ability for firm imports.

87 2023 Integrated Resource Plan: Pathways to a Net-Zero Electricity System. NB Power. 2023.

88 Hourly Transmission Flow Data provided by NB Power.

89 We assume, for this analysis, that these export agreements remain in place through the study horizon.

However, this is expected to change upon completion of the New Brunswick/Nova Scotia Interprovincial Transmission Line Project (discussed in the next section).[90]

NB Power maintains a non-firm Reserve Sharing Agreement of 168 MW of Ten-Minute Reserve and 50 MW of Thirty-Minute Reserve with Nova Scotia Power. However, during winter peak conditions, it is probable that Nova Scotia Power would face simultaneous reliability stress, rendering those reserves unavailable.[91] For planning and operational reserve requirements, NB Power does not rely on non-firm reserve sharing agreements and thereby assumes zero firm support from Nova Scotia Power.

Maritime Electric (Prince Edward Island)

NB Power's link to Maritime Electric consists of submarine cables with a 300 MW export capability. Nearly all of this capacity is under firm export contract from New Brunswick to Prince Edward Island. These facilities do not provide any firm import capability into New Brunswick.[92]

Northern Maine ISA

NB Power is connected to NMISA through two export-oriented ties: a 32 MW connection to Eastern Maine Electric Coop and a 134 MW connection to Versant (Maine Public Service). Both are firm export contracts totaling 168 MW and provide no import capability into New Brunswick. [93]

Hydro-Québec

NB Power's interface with HQ is nominally limited to 1,200 MW of imports, constrained by HQ's 315 kV network between Lévis and the Gaspé Peninsula. Imports flow either through two HVDC converter stations—Eel River (335 MW) and Madawaska (438 MW)—with a combined maximum transfer capability of 773 MW, or via radial transfers electrically tied to HQ and separated from New Brunswick generation. Radial transfers are further limited by voltage stability within New Brunswick to 425 MW during peak demand hours. As a result, effective import capability is bounded both by HQ's internal transfer limits and by New Brunswick's own conversion and radial constraints. [94]

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90 Summary of transmission topology and constraints provided by NB Power.

91 Resource Adequacy Report. New Brunswick Power. March 18, 2024.

92 Summary of transmission topology and constraints provided by NB Power to The Brattle Group

93 *Id.*

94 *Id.*

During periods of extreme cold, HQ's internal transmission congestion and capacity stress can further restrict exports. Much of HQ's hydro generation originates in the north and must flow south before looping back east toward the Gaspé Peninsula, where the New Brunswick interconnections are located. This flow is constrained by transmission bottlenecks in the Québec City–Gaspé corridor, precisely at the same time that both Québec and New Brunswick experience peak winter heating loads. While projects to alleviate these bottlenecks are under discussion, they are long-term in nature and not expected to be in place within the current planning horizon.[95]

Though HQ maintains firm export agreements with other regions, NB Power's relationship with HQ is not backed by capacity. Therefore, any exports from HQ to New Brunswick are curtailable in favor of HQ's native load and/or capacity-backed export agreements. As a result, while the nominal transfer capability appears significant, NB Power cannot rely on firm imports from HQ in its reliability assessments, and models availability of firm imports from HQ as zero.

ISO New England

NB Power's interface with ISO-NE consists of two 345 kV AC lines. Under normal operation with PLNGS in service, the firm import limit is 200 MW, rising to about 400 MW with PLNGS out of service. These limits are defined by voltage and transient stability in southern New Brunswick and northern Maine. In addition, a Presidential Permit (PP-89-2) authorizes a maximum transfer of 550 MW. However, achieving this level would require additional dynamic reactive devices (e.g., STATCOMs) in southern New Brunswick and northern Maine. [96]

NB Power maintains a 200 MW non-firm Reserve Sharing Agreement with ISO-NE, but in practice, it is highly unlikely that these reserves would be available during peak winter conditions due to regional reliability limits.[97] For reliability assessments, NB Power assumes zero firm capacity imports from ISO-NE.

Upcoming Transmission Expansion

The primary project expected to enhance New Brunswick's transmission capability by the end of the decade is the New Brunswick–Nova Scotia Interprovincial Transmission Line Project. Currently, the two provinces are connected by a single 345 kV transmission line. The project aims to increase interprovincial transfer capability by effectively twinning a 65-km section of

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[95] Transmitting the Energy of Our Goals: Upgrading of the Main Transmission System. Hydro-Québec. 2024.

[96] Summary of transmission topology and constraints provided by NB Power to The Brattle Group

[97] Resource Adequacy Report. New Brunswick Power. March 18, 2024.

the existing corridor from Salisbury through Memramcook to the New Brunswick–Nova Scotia border.[98]

Once in service, Nova Scotia's import limit from New Brunswick is expected to roughly double, due to reduced contingency risk, and NB Power's power exchange with Nova Scotia will no longer depend on a single line. However, the project does not directly add new firm import capacity to New Brunswick's system.[99] Therefore, while it strengthens regional interconnection and reliability, this transmission upgrade is not a suitable near-term solution for addressing New Brunswick's emerging supply deficit.

FUTURE FIRM IMPORT CAPABILITY

Beyond the theoretical transfer capability of New Brunswick's interties, it is important to examine how these transmission assets are utilized in practice. Historical flow patterns provide critical insight into whether additional headroom exists on the regional system and, more importantly, whether that headroom can realistically be leveraged to support reliability needs.

Transmission Headroom

Figure 7 presents flow duration curves for all of New Brunswick's interconnections, covering every hour from January 2022 through March 2025. In these curves, positive values indicate exports from New Brunswick, while negative values indicate imports.

A clear trend emerges: although the province maintains substantial transfer capability with its neighbors, these interconnections are rarely utilized at their full limits. For example, the Québec tie, with a transfer capability of up to 1,200 MW, has rarely been fully used over the same period.

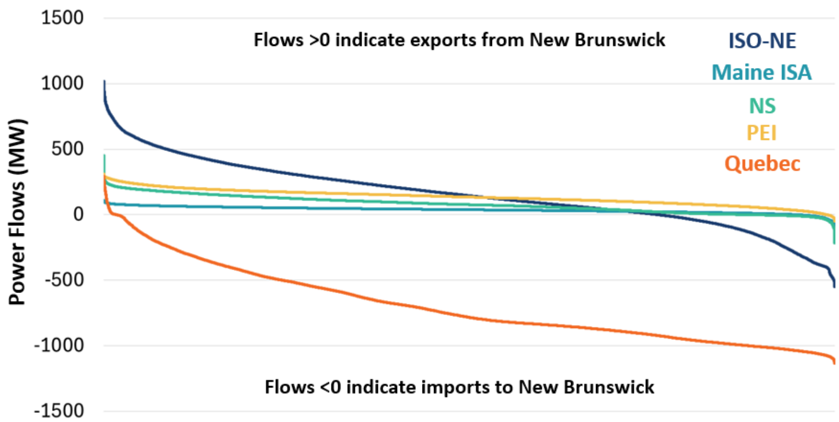
This pattern suggests that, in aggregate, New Brunswick's interties are underutilized relative to their design capacity. However, it is important to emphasize that this apparent "headroom" does not translate into dependable imports for adequacy planning. Surplus transfer availability in historical data does not guarantee firm import supply in future stress conditions, particularly during regional peak periods when neighboring systems are also constrained. Finally, while the submarine tie with Prince Edward Island is technically bidirectional, imports into New

98 CIB Commits $217 Million for 160 km, 345 kV Nova Scotia to New Brunswick Reliability Intertie. T&D World. 2025.

99 New Brunswick / Nova Scotia Interprovincial Transmission Line Project. NB Power. Accessed September 2025.

Brunswick are extremely rare. In practice, apart from Québec, New Brunswick has consistently been a net exporter of electricity to its neighbors.

FIGURE 7: HISTORICAL TRANSMISSION FLOW DURATION CURVES[100]



Total Transfer Capability

Area	MW to NB	MW from NB
ISO-NE	550	1,000
Maine ISA	166	166
NS	350	300
PEI	300	300
Quebec	1,200	773

Figure 8 further illustrates these dynamics by showing monthly average flows, with shaded areas identifying New Brunswick's winter peak season. Exports to neighboring regions still occur during NB Power's peak, since most are a result of firm contracts. At the same time, flows from HQ into NB Power approach their effective limits in winter, with HQ consistently delivering close to 400 MW into NB Power even after accounting for wheeling transactions (Figure 9). This suggests that, of all New Brunswick's neighbors, Québec has historically been the most reliable counterparty for imports, particularly during peak periods.

[100] Hourly Transmission Flow Data provided by New Brunswick Power

FIGURE 8: MONTHLY AVERAGE TRANSMISSION FLOWS TO/FROM EACH NEIGHBORING REGION [101]

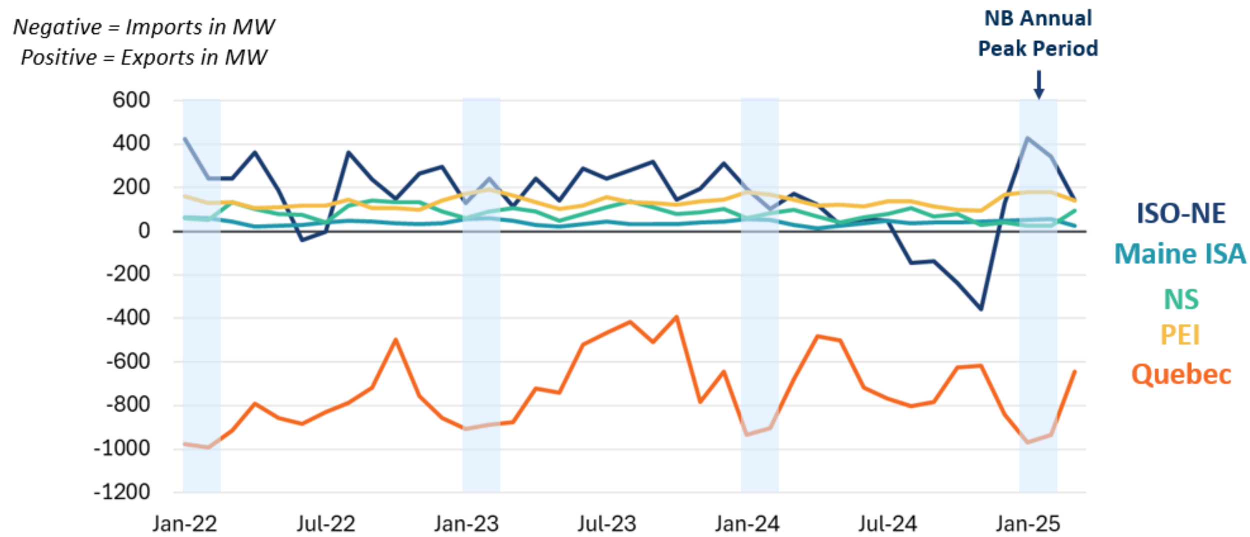
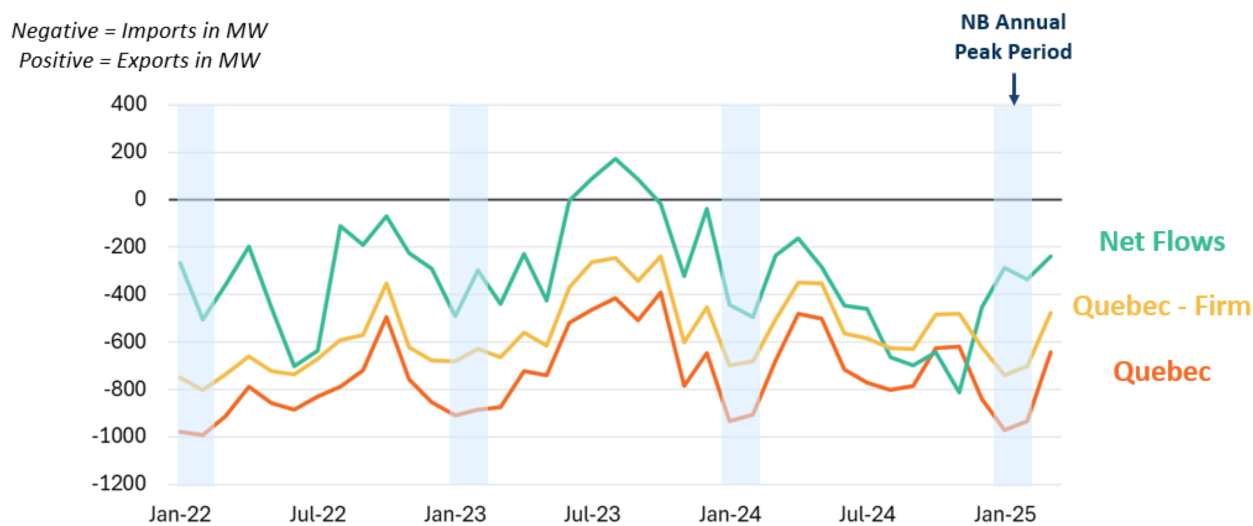


FIGURE 9: AVERAGE TRANSMISSION FLOWS FROM HYDRO-QUÉBEC [102]



Note: "Net Flows" is the balance of all import and export transmission flows.

To assess whether imports could realistically serve as a substitute for new in-province resources, we next examine the supply headroom available in neighboring regions and the extent to which it can be relied upon during periods of New Brunswick's peak demand.

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[101] *Id.*

[102] *Id.*

Firm Capacity Potential in Neighboring Regions

While New Brunswick's interties provide the physical ability to import power, the reliability of such imports ultimately depends on whether neighboring regions have surplus capacity available to sell. Understanding the availability of surplus firm sources of supply in adjacent systems is therefore critical for assessing whether external resources can serve as a dependable substitute for new in-province capacity.

All of New Brunswick's Canadian neighbors are winter-peaking systems. As a result, they cannot be considered a reliable source of firm imports when NB Power's system is under greatest stress. HQ consistently exports significant volumes during NB Power's winter peaks, while ISO-NE remains, for now, a summer-peaking system with potential excess supply during winter periods. These two regions therefore represent the most credible opportunities to explore for firm imports into New Brunswick.

Maritime Electric (Prince Edward Island)

Maritime Electric has historically relied heavily on imports from NB Power—up to 300 MW—to serve peak demand. Electrification of space heating, driven by customer incentives to switch from oil, is now pushing load growth at a faster pace. Maritime Electric's peak demand is forecast to grow from roughly 300 MW in 2021 to 456 MW by 2040.[103] To meet this increase, Maritime Electric plans to develop more on-island generation resources, but in the interim, it remains a net purchaser of capacity, with continued reliance on NB Power for support. This structural dependence reduces the likelihood that Maritime Electric could contribute to firm imports into New Brunswick during winter peaks.

Nova Scotia Power

Nova Scotia Power faces even sharper challenges, with climate policy mandating the retirement of approximately 1.2 GW to 1.5 GW of dependable coal-fired capacity by 2030, even as electrification adds around 200 MW of incremental peak demand. The province's existing fleet of natural gas, oil, and hydro generation—combined with minor imports—is insufficient to cover this emerging capacity gap. Nova Scotia Power's IRP recognizes this and identifies the need for substantial new resources. All modeled scenarios converge on roughly 1.5 GW of additional onshore wind by 2030 (tripling existing capacity to approximately 2.1 GW),

[103] Prince Edward Island Resource Planning and Maritime Electric Capital Expenditures: Alternatives to MECL Integrated System Plans and Impact on MECL Capital Expenditures. Prepared for the PEI Regulatory and Appeals Commission. April 2022.

supplemented by approximately 200 MW of new utility-scale solar PV. However, given the variability of wind and solar, Nova Scotia Power also requires 300 MW to 600 MW of new fast-start thermal generation or equivalent firm resources by 2030 to backstop renewables and maintain reliability. Even as transmission upgrades strengthen ties across the Maritimes and Nova Scotia adds additional capacity, the coincidence of winter peaks, rising electrification, and policy-driven retirements means that the province is unlikely to have surplus firm capacity to export to New Brunswick in the years ahead.

Northern Maine ISA

NMISA is a very small balancing area that continues to operate as a net purchaser of electricity, often relying on NB Power to meet its needs. It does not represent a source of firm imports for New Brunswick.

Hydro-Québec

Though HQ is a winter-peaking system, it has long been viewed as a reliable source of surplus hydroelectricity. That picture is changing. HQ's own planning now emphasizes growing domestic demand, new resource needs, and an evolving role in regional markets. For New Brunswick, this means the assumption of HQ as a dependable winter supply partner is increasingly uncertain.

HQ forecasts that electricity demand will rise by about 25 TWh (12.5%) from 2022 to 2032, with peak demand increasing by 4 GW (10%), driven by transportation and continued heating electrification, industrial decarbonization, and the growth of new sectors such as green hydrogen, battery manufacturing, and data centers.[104] Due to this demand growth, HQ is identifying a capacity deficit in its system by the winter of 2026/2027 and HQ's latest Action Plan identifies a need for 8 GW to 9 GW of new capacity by 2035.[105,106] This includes upgrades to its in-province hydropower generators, investments in wind generation, as well as significant development of its contracted hydro fleet in Labrador: the expansion of Churchill Falls (+550 MW) and the addition of Churchill Falls 2 (+1,100 MW) and Gull Island (+ 2,250 MW). However, these facilities would not come online until the mid-2030s.[107] In the meantime, HQ has already

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[104] Overview of Hydro-Québec's Energy Resources. Hydro-Québec. October 2022.

[105] Strategic Plan 2022-2026. Hydro-Québec. March 2022.

[106] Towards a Decarbonized and Prosperous Québec: Action Plan 2035. Hydro-Québec.

[107] Capacity will be gradually added to the existing Churchill falls station between 2028 and 2038. Commissioning of Churchill Falls 2 and Gull Island is planned for 2034. Source: An Ambitious Transition: Annual Report 2024. Hydro-Québec. March 2025.

shifted from being a consistent net exporter to a system occasionally seeking imports. In 2024, it extended its capacity-sharing agreement with Ontario for up to ten more years, under which Ontario provides 600 MW of winter capacity in exchange for 600 MW of summer capacity from Québec.[108] These moves underscore HQ's transition from a net exporter of surplus to a system increasingly focused on meeting its own adequacy needs, with former CEO Michael Sabia acknowledging that Québec must "change the game" to meet rising demand.[109]

Several structural factors are intensifying HQ's winter peak and forcing the system to adapt:

- **Electrification and new industrial loads:** Québec already has one of the highest rates of electric heating in Canada, and electrification of transport and industry is accelerating. HQ forecasts demand growth of +25 TWh (+14%) and +4 GW of capacity by 2032 despite efficiency measures.[110] Large new loads include data centers (4.1 TWh), green hydrogen (2.3 TWh), and EV battery plants (1.2 TWh).[111] These sectors add demand year-round, including during winter peaks. By 2029–30, HQ anticipates a capacity shortfall unless new supplies are online.[112]
- **Temperature sensitivity:** Even under normal growth, HQ's peak is extremely temperature-sensitive due to pervasive electric heating. A few degrees drop in temperature can add hundreds or thousands of megawatts to demand. (NB Power's experience is approximately 30 MW per degrees Celsius; in HQ the absolute effect is much larger given size of the Québec system). During the January 2022 cold wave, demand overshot the prior winter by about 2,000 MW.[113] To maintain reliability, HQ must keep sufficient reserves to cover such extremes, leaving little capacity available for export. Importantly, because New Brunswick experiences similar weather patterns and also relies heavily on electric heating, the two systems tend to peak simultaneously, meaning HQ has the least ability to spare capacity exactly when New Brunswick needs it most. For example, during a cold weather event on February 3, 2023, HQ effectively cut exports to NB from 1,000 MW to zero at the exact time NB Power was experiencing extremely high demand and weather-related supply issues.[114]
- **Policy and reliability standards:** Québec's regulatory and policy framework compels HQ to meet in-province requirements first. The utility plans its system to a mandatory firm load

[108] Ontario-Québec New Electricity Trade Agreement news release. Government of Ontario. August 30, 2023.

[109] Hydro-Quebec turning to wind power for new energy production. Timothy Sargeant, Global News. May 30, 2024.

[110] Overview of Hydro-Québec's Energy Resources. Hydro-Québec. October 2022.

[111] *Id.*

[112] *Id.*

[113] *Id.*

[114] NPCC Cold Weather Lessons Learned Webinar. NB Power. Nov 28, 2023.

shedding risk of 2.4 hours/year (equivalent to 1-in-10 LOLE), similar to NB Power's criteria. If capacity is tight, exports (especially non-contractual, spot exports) are the first thing HQ will cut. For example, in early 2023, HQ suspended most spot exports to ISO-NE for several weeks—not for political reasons, but to conserve water for potential winter extremes.[115] ISO-NE went almost a month with virtually no cross-border flow from HQ in March 2023, a clear demonstration that HQ will curtail discretionary exports when its own system is under stress.[116]

Hydrological volatility has further reduced HQ's export flexibility. Drought conditions in recent years have significantly reduced reservoir levels, cutting exports from 35 TWh to 36 TWh (2020–2022) to 23 TWh in 2023 and only 15 TWh in 2024.[117] In 2024, HQ explicitly stated it was limiting exports to manage low runoff and would continue doing so until conditions improve.[118] Although firm contractual deliveries were maintained during these drought periods, discretionary sales—including potential short-term flows to neighbors—were cut back significantly. HQ has begun importing power to adapt to such conditions. For instance, in winter 2022/2023, HQ bought power from neighbors (including New York and Ontario) to preserve reservoir levels.[119] Together, these episodes underscore the diminishing reliability of surplus hydro as a consistent export source and HQ's growing emphasis on prioritizing its own system adequacy.

At the same time, HQ's exportable surplus is increasingly committed under long-term contracts with U.S. counterparties. According to existing contracts, it must deliver 1,200 MW to Massachusetts (over the New England Clean Energy Connect line) and 1,250 MW to New York (via the Champlain-Hudson Power Express line).[120] These contractual commitments constrain HQ's ability to export capacity to New Brunswick. In particular, the Massachusetts contract includes stringent delivery requirements and significant penalties for non-performance.[121] Until substantial new generation (i.e., wind farms, hydro plants) comes online in the 2030s, HQ's

115 Low Water Levels Explain Decline in Quebec Hydro Exports. Mitchell Beer, The Energy Mix. Aprill 11, 2025.

116 Monthly electricity export data is available from the Canadian Energy Regulator's website.

117 An Ambitious Transition: Annual Report 2024. Hydro-Québec. March 2025.

118 Low Water Levels Explain Decline in Quebec Hydro Exports. Mitchell Beer, The Energy Mix. Aprill 11, 2025.

119 Canadian Electricity Regulator and over 1.3 TWh of imports from Ontario in the first 3 months of 2023 according to IESO Data Directory

120 Exports to New England webpage. Hydro-Québec. Last accessed October 27, 2025; Champlain-Hudson Power Express Line website, last accessed October 27, 2025.

121 Massachusetts DPU Commission Order for Dockets 18-64, 18-65, and 18-66. Massachusetts Department of Public Utilities. June 15, 2019.

exportable surplus will remain tightly allocated, leaving limited opportunity for NB Power to secure capacity-backed export arrangements.

Taken together, Québec's rising domestic demand, coincident winter peaks, temperature sensitivity, hydrological volatility, and binding U.S. contracts significantly limit its ability to provide reliable surplus capacity to New Brunswick. While HQ will continue to trade opportunistically in short-term markets, its priority will remain securing domestic reliability and meeting firm export obligations. For New Brunswick, this means that HQ cannot be relied upon as a dependable source of firm winter capacity in the near to medium term.

ISO New England

ISO-NE remains one of the more plausible sources of surplus winter supply in the near-term (before the mid 2030s) for New Brunswick. ISO-NE currently operates as a summer-peaking system, leaving theoretical supply headroom in the winter to support New Brunswick. Additionally, though current transmission stability issues restrict import capability into New Brunswick to 200 MW (400 MW with PLNGS out of service), investments in dynamic reactive devices could increase this capability to 550 MW, enough to cover New Brunswick's near-term resource deficit. However, multiple other barriers limit the practicality of relying on this market for firm imports.

First, seasonal reserve margins in ISO-NE are rapidly shrinking. Current margins of about 20% are projected to fall to just 10–11% by 2032, forcing the region to concentrate increasingly on meeting its own adequacy needs. [122] At the same time, winter demand is growing faster than summer: winter peaks are forecast to rise by roughly 29% (+6 GW) through 2032.[123] By 2031, extreme winter loads are expected to surpass normal summer peaks, and NERC projects that ISO-NE will become a winter-peaking system by the mid-2030s.[124] This transition, driven largely by heating electrification, will reshape the load curve, producing sharp morning winter peaks that resemble New Brunswick's own system profile.

ISO-NE's declining winter capacity margins highlight this trend. According to NPCC reliability reports (Figure 10), the region's P50 winter margin peaked at 25.2% (5,086 MW) in 2020/2021 but has since fallen steadily to 10.4% by 2024/2025. Under P10 and more extreme scenarios, margins turn negative by 2024/2025. This underscores ISO-NE's growing system tightness and

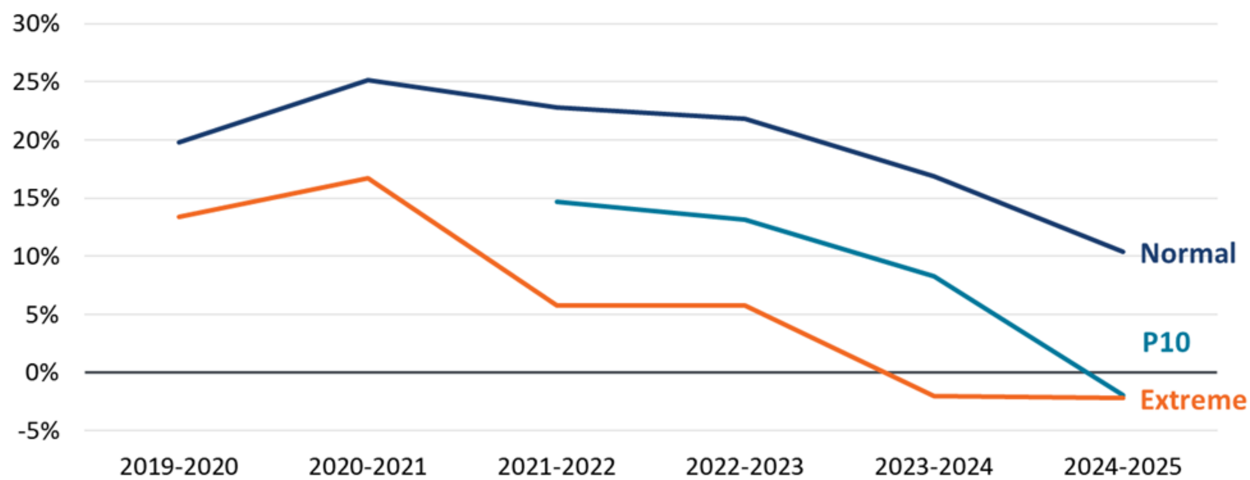
[122] 2023 Regional System Plan. ISO New England. November 1, 2023

[123] *Id.*

[124] NERC 2024 Long-Term Reliability Assessment. December 2024.

the increasing likelihood that it will have little to no surplus to support New Brunswick during its winter peak.

FIGURE 10: ISO-NE WINTER RESERVE MARGINS 2019/2020 – 2024/2025[125]



The near-term supply outlook in Maine (the ISO-NE portion of) also underscores the limited potential for surplus support. Maine is a particularly important area to examine because, while it has limited ability to export power south into the rest of New England due to transmission constraints, it is directly interconnected with New Brunswick. If Maine had significant excess capacity that could not flow south, that capacity might instead be available to support New Brunswick.

However, recent market outcomes show that this is not the case. Most of Maine's 3,200 MW of capacity clears in ISO-NE's Forward Capacity Auctions, serving both its own local peaks and flows to southern New England, often up to transmission limits. Very little capacity remains uncleared (3 units adding up to about 375 MW), and what does remain consists mainly of small cogeneration plants that would be unlikely candidates for contracting by NB Power. Offshore wind projects, which would increase Maine's excess capacity substantially, face uncertain political support[126] and, even if built, these projects are unlikely to come online before 2040, well beyond the planning horizon discussed in this report.[127]

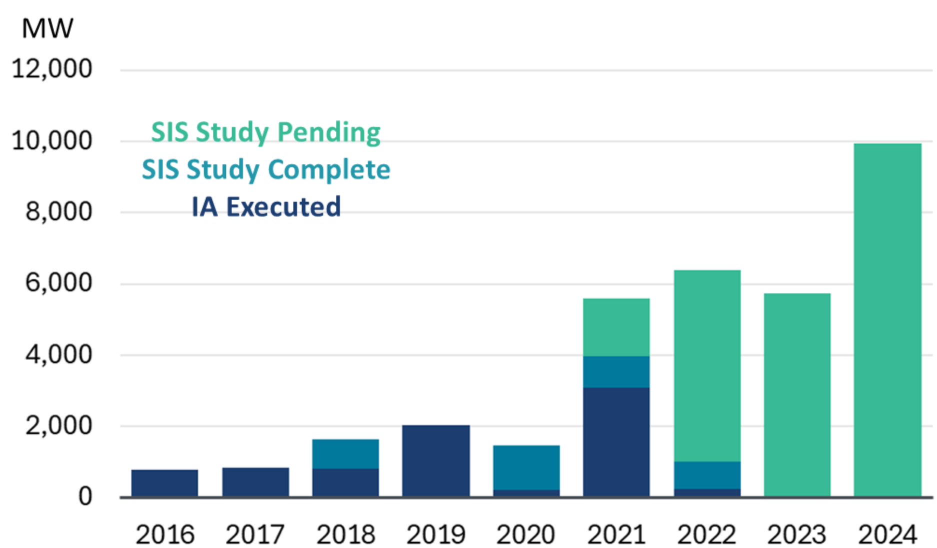
125 Winter and Summer Reliability Assessments, years 2019-2025. NPCC.

126 Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects, 90 FR 8363. The White House. January 20, 2025.

127 2050 Offshore Wind Analysis. ISO-NE. March 21, 2025.

The prospect of adding new capacity in ISO-NE faces major hurdles. The generator interconnection (GI) queue already exceeds 34 GW, with over 98% comprised of solar, wind, or storage (Figure 11). Projects face multi-year delays: the most recent project to clear a System Impact Study (SIS) and sign an Interconnection Agreement (IA) entered the queue nearly three years ago. While ISO-NE is working to streamline the GI process,[128] new resources will still face extended timelines before reaching operation. This backlog represents a critical barrier to near-term capacity growth and further constrains the availability of reliable surplus supply.

FIGURE 11: ISO-NE INTERCONNECTION QUEUE BY STUDY STAGE AND REQUEST YEAR[129]



Even if sufficient capacity were available, several institutional and operational barriers limit the ability to contract firm imports from ISO-NE:

- **Capacity accreditation and market rules:** Under Section 13 of ISO-NE Market Rule 1, the Forward Capacity Auction (FCA) Qualified Capacity of any non-intermittent resource is set at the lesser of its summer and winter capacity values.[130] As a result, a generator cannot commit capacity only for the winter and still receive accreditation; instead, it must assume an annual obligation. Cleared capacity resources are also subject to a must-offer requirement in both the Day-Ahead and Real-Time energy markets throughout the year.[131]

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[128] Notes: ISO-NE is currently switching to a cluster study process. Projects that have not completed a system impact study before August 2024 will be processed in a transitional cluster study. Source: ISO-NE Interconnection Request Queue webpage.

[129] Interconnection Request Queue. ISO New England. Accessed September 2025.

[130] *See* ISO Tariff Section III, Market Rule 1 - Section 13, p. 24, Section III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources. ISO-NE. May 3, 2025.

[131] ISO NE Manual for the Forward Capacity Market (Manual M-20). ISO-NE. April 6, 2023.

Together, these provisions prevent resources from making seasonal firm capacity commitments to New Brunswick. Although ISO-NE is considering a shift to seasonal accreditation as early as 2028, this reform is not yet certain and would require delisting resources from ISO-NE's capacity market. [132]

- **Political risks:** Cross-border trade is constrained by tariff exposure and a 550 MW ceiling under the U.S. Presidential Permit governing exports to Canada. These limits reduce the attractiveness of pursuing international firm import transactions.
- **Transmission service:** ISO-NE does not offer firm point-to-point transmission service within its network, meaning resources cannot guarantee delivery to the New Brunswick border. Additionally, energy exports are subject to curtailment during internal system congestion or reliability events.
- **Fuel supply constraints:** Much of New England's dispatchable generation fleet is natural gas–fired, and during extreme cold weather, limited pipeline capacity constrains availability. This has led many gas-fired generators to convert to dual fuel, with fuel oil used as back-up during periods of natural gas scarcity. This could reduce the reliability and increase the costs of imports precisely when New Brunswick would need them the most.

Taken together, these factors—tightening system margins, Maine's limited surplus, barriers to new build, restrictive capacity rules, political risks, lack of firm transmission, and winter fuel vulnerabilities—highlight the significant challenges of relying on ISO-NE for firm capacity imports. While transmission upgrades and market reforms may improve the outlook over time, the near-term pathway to securing large-scale, reliable imports from New England remains highly uncertain.

Conclusion: Firm Imports are not a Realistic Option for New Brunswick at this Time

Although New Brunswick maintains 2,448 MW of nominal intertie transfer capacity, the amount that can realistically be relied upon as firm imports during peak winter conditions is extremely limited under current system constraints. Interfaces with HQ, ISO-NE, and Nova Scotia Power are all limited by thermal, voltage, and stability considerations, while reserve sharing agreements cannot be assumed to deliver capacity when all systems are under simultaneous winter stress. Historical practice and NB Power's own adequacy assessments confirm this

[132] ISO-NE Capacity Auction Reforms Key Project webpage. Last accessed October 27, 2025.

reality: in both operational and planning reserve studies, firm imports are modeled at or near zero.[133]

This technical limitation is compounded by tightening supply conditions in neighboring jurisdictions:

- Nova Scotia Power faces the retirement of 1.2 GW to 1.5 GW of coal by 2030, new electrification-driven load, and the need to build 300 MW to 600 MW of firm backup even after 1.5 GW of new wind, leaving little capacity to spare.
- HQ is facing demand rise by +25 TWh and +4 GW by 2032, drought-driven volatility, coincident winter peaks with New Brunswick, and 2.4 GW of binding U.S. export contracts coming online by 2025. These factors severely limit HQ's ability to provide reliable surplus.
- ISO-NE is still technically summer-peaking but trending toward winter-peaking by the early 2030s, with reserve margins falling from 20% today to 10–11% by 2032, Maine's limited ability to offer surplus, a clogged interconnection queue, and market rules and fuel constraints that complicate firm export commitments.

In other words, the issue is not just that New Brunswick's interties are physically constrained, but that its neighbors have little dependable surplus to offer during coincident winter peaks. Even the two most plausible sources of supply—HQ and ISO-NE—are facing tightening margins, structural export barriers, and competing obligations that limit the reliability of firm imports in the near to medium term.

Taken together, these findings demonstrate that while imports may play a limited, opportunistic, or complementary role, they cannot substitute for new in-province firm, dispatchable generation. To maintain reserve margins and meet reliability standards, New Brunswick must plan to secure its own dependable resources rather than assuming neighboring systems will have capacity to spare when it is needed most.

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133 This conclusion is consistent with NB Power's 2023 Integrated Resource Plan, which found that the existing ties are insufficient to replace a 400 to 467 MW resource (such as Belledune) with imports "without significant capital investment and lead time to construct transmission infrastructure." The IRP also highlighted uncertainty around the availability of energy and long-term agreements needed to back firm imports, deeming the option infeasible under present conditions. The 2024 Maritimes Area Interim Review of Resource Adequacy similarly limited tie benefits from neighboring NPCC Areas to 300 MW across all years.

V. Economics Considerations

The previous Sections analyzed how procuring at least 300 MW to 400 MW of new firm capacity is a prudent hedge against the future system evolution (including load growth) and that securing that amount from imports is not easily feasible, suggesting NB Power should built the resources within the province. In this Section, we review the potential risks and benefits of developing the new resource within New Brunswick.

Low Stranded Asset Risk

Analysis in the previous two Sections indicate that additional supply can either serve domestic reliability needs or be exported to well-established neighboring markets, as they too will likely become tight in supply. Therefore, new capacity in New Brunswick appears to have a low risk of becoming a stranded asset.

NB Power is interconnected with ISO-NE, Nova Scotia Power, Maritimes Electric, NMISA, and HQ (with further transmission expansion planned), all of which continue to show demand for reliable capacity, energy, and ancillary services. If domestic needs materialize later than expected, surplus capacity can be monetized in several ways:

- **Capacity exports/sales.** Resources not immediately required within New Brunswick could potentially be sold into ISO-NE capacity market through firm export agreements or into Canadian neighboring systems such as HQ through bilateral contracts.
- **Energy exports.** Power can flow south into ISO-NE during winter peaks, west into Québec to help balance hydro operations during droughts or low-water periods, or into other neighboring provinces, such as Nova Scotia or Prince Edward Island, to help serve system needs amid load growth and supply overhauls.
- **Ancillary services.** Operating reserves, frequency regulation, and balancing services can be provided to ISO-NE, HQ, and Nova Scotia Power, all of which increasingly value flexibility to support renewable integration.

At the same time, NB Power’s 2023 IRP shows significant new supply will be required under virtually all modeled scenarios. Coal retirements, eventual phase-out of oil-fired generation, and the finite life of PLNGS all create firm capacity gaps that must be addressed. Even with growth in renewables and storage, the IRP highlights the continued need for dependable, dispatchable supply. Facilities such as the Bayside Generating Station, which can be extended at relatively low cost, illustrate how maintaining or adding firm thermal resources will remain essential to system reliability.

One approach that could be considered to reduce the risk of stranded asset cost might be to separate the 400 MW investment into several incremental investments over time, as needs emerge. However, in practice this approach is likely to lead to higher costs over the long-term, assuming load growth materializes as forecasted. Building multiple smaller facilities would require duplicative environmental reviews, site preparations, mobilizations, fuel storage, and pipeline connections, all of which drive up development costs.[134] Smaller projects are also more expensive and difficult to procure. NB Power learned, through its solicitation for RIGS, that may developers are not willing to pursue projects under 300 MW.[135] Operating costs for smaller facilities would also be higher, particularly if assets were located outside New Brunswick, where tariffs and other cross-border logistics could apply. Finally, interconnection processes in other jurisdictions add significant schedule uncertainty, making it likely that commercial operation dates would slip well into the 2030s.

These factors demonstrate that new in-province capacity built today is likely the preferred option and that it will not become stranded. Whether used domestically to meet firm reliability needs or exported into neighboring markets, additional supply represents a prudent investment in both system adequacy and long-term flexibility.

IN-PROVINCE BENEFITS

Building 400 MW of new generation capacity within New Brunswick would deliver important local economic and social benefits while strengthening system reliability. Constructing the facility in-province would provide a strategic hedge against electricity market volatility, regulatory changes, and evolving market rules. Should the alternative be importing from the U.S., additional risks would include exposure to cross-border transmission tariffs, which are governed by the U.S. Presidential Permit process, together with any trade tariffs. These tariff costs are uncertain and outside NB Power's control; local investment avoids them and ensures greater cost stability for ratepayers.

By contrast, developing capacity in neighboring regions would forgo these economic benefits and introduce significant cost and schedule risks. NB Power's experience shows that importing firm capacity from out-of-province plants adds a transmission premium of 5% to 20%. Long-term operating costs would also be higher, particularly for assets located outside Canada, for

[134] Construction near an operating power plant could also lead to higher costs, such as those associated with land use or limitations on construction activities.

[135] Exhibit M-12. Supplemental Filing re: On-Island Capacity for Security of Supply Project of Maritime Electric Company, Ltd. August 14, 2025

example, maintaining a U.S.-based facility could expose NB Power to tariffs of up to 25% on replacement parts. The GI processes in other jurisdictions add further uncertainty, with commercial operation potentially slipping well into the 2030s. An alternative option such as developing new capacity in Prince Edward Island is similarly uncompetitive, with estimated capital costs of roughly being 10% or 20% higher than building it within New Brunswick. [136] Furthermore, the limited availability of natural gas on Price Edward Island will require the new facility to rely on fuel oil, suggesting that operating costs would also be higher than operating it within New Brunswick using natural gas.

And though perhaps not an explicit consideration for the NBEUB review, new capacity built within New Brunswick would also make a direct economic contribution to the province, including tax and employment benefits. Property taxes and other fiscal contributions during both construction and operation would provide a recurring source of revenue to support public services and infrastructure. Keeping this revenue in-province ensures that the economic value flows to New Brunswick communities rather than external jurisdictions. The construction phase would generate a significant number of short-term jobs across multiple trades, while ongoing operations would sustain long-term, high-quality positions in plant operation and maintenance. These jobs support workforce development and training in the province, with additional indirect and induced employment benefits through supply chains and local services.

[136] Exhibit M-12. Supplemental Filing re: On-Island Capacity for Security of Supply Project of Maritime Electric Company, Ltd. August 14, 2025

VI. CONCLUSIONS

NB Power has identified a potential near-term supply shortfall and has determined that the RIGS project is the best way to address the emerging reliability needs. Brattle was retained to review whether the RIGS project, which consists of a new 400 MW gas-fired generation facility with dual-fuel capability, is justified based on system reliability and operational considerations.[137]

Our assessment began with a review of NB Power's overall analytical approach. We confirmed that the methodology taken by NB Power aligns with accepted industry practices. We then reviewed various planning documents of New Brunswick and neighboring regions and further examined the key planning assumptions underlying NB Power's conclusion that the RIGS project is necessary.

Reviewing various planning documents of New Brunswick and neighboring regions highlighted a tightening of the supply/demand balance throughout the region. Many of the recent studies show that the region will be short in capacity within the next few years. Brattle further analyzed NB Power's future load and resource portfolio by altering several key assumptions underlying NB Power's load forecast and resource outlook. This analysis evaluated reliability through both planning reserve-based (incorporating uncertainties related to drivers of peak demand) and operational requirement-based (largely incorporating supply-side uncertainties) criteria. Brattle's analysis concluded that by 2030 under the Reference and Adverse Conditions Scenarios, New Brunswick faces deficits of 279 MW to 1,574 MW in the operational requirement-based analysis and 308 MW to 1,199 MW in the planning reserve-based analysis. We find the analysis results, together with planning study reviews, justify consideration of an additional 400 MW of firm generation capacity. In addition to being required to meet near term domestic reliability needs, such a resource would serve as an insurance against unanticipated load growth and other uncertainties that are difficult to fully capture in forecasts. It would also provide greater certainty in managing the province's largest single contingency and help mitigate deliverability risks, such as transmission congestion or other constraints within neighboring systems, that could limit the availability of imports when they are most needed.

At present, New Brunswick cannot reliably rely on 400 MW of firm import capacity during peak periods. The existing intertie system with neighboring systems imposes hard limits: for example, a single contingency on one of the main tie lines could instantly remove hundreds of

[137] Brattle's role as an outside expert is to deem whether this investment, at this period in time, is prudent for NB Power to meet certain reliability standards.

megawatts of imports, leaving NB Power to cover the loss from its own reserves. Firm transmission rights for large imports have not been secured, and neighboring systems do not have surplus generation to offer. All Maritime Area utilities are winter peaking, competing for capacity and rely on NB Power to help them meet their own peak needs, and could not support firm exports to New Brunswick. HQ and ISO-NE, the most likely candidates for providing exports to New Brunswick, are both facing significant winter load growth and are required to prioritize their own domestic requirements and pre-existing export contracts. Without a firm contract, system-backed rights, and redundant transmission paths, it would not be prudent for NB Power to count on 400 MW of imports as dependable capacity today.

Looking forward, planned transmission upgrades could expand import capability. The 345 kV New Brunswick–Nova Scotia intertie, slated for completion near 2028, will strengthen east–west flows within the Maritimes. If built, NB Power could explore firm, system-backed imports with greater confidence that transmission paths exist to deliver them even during peak hours. However, these projects are not in place today and cannot be relied on as a source of firm imports. And Nova Scotia, with a large capacity of coal-fueled resources retiring amid its growing load, may not be able to provide surplus generation to New Brunswick. These observations lead to the conclusion that building the new resources in province to be the most appropriate solution to deal with the potential resource shortage that NB Power foresees could happen within the next few years.

In addition to it being a prudent investment for maintaining system reliability, building 400 MW of new generation capacity in New Brunswick would deliver substantial local economic and social benefits while enhancing power system reliability. The project would expand the provincial and municipal tax base, with construction and operations generating recurring revenues to support local services and infrastructure. It would also create significant short-term construction jobs and sustain long-term, high-quality operational positions, fostering workforce development and training. In addition, indirect and induced employment through supply chains and local services would further strengthen the province's economy, ensuring that economic value stays within New Brunswick communities.

Overall, based on our review, we find NB Power's decision to pursue the RIGS project within its service territory to be both reasonable and appropriate, given the reliability and planning criteria evaluated together with operational requirements.[138]

[138] NB Power's decision is subject to approval by the NBEUB.

APPENDIX

GLOSSARY

AAR	Alkali–Aggregate Reaction
DER	Distributed Energy Resources
DR	Demand Response
DSR	Demand Side Resources
EV	Electric Vehicle
FCA	Forward Capacity Auction
GDP	Gross Domestic Product
GI	Generator Interconnection
HQ	Hydro-Québec
IA	Interconnection Agreement
IRP study	Integrated Resource Planning study
ISO-NE	ISO New England
LOLE	Loss of Load Expectation
MLAP	Mactaquac Life Achievement Project.
MSSC	Most Severe Single Contingency
NB Power	New Brunswick Power
NBEUB	New Brunswick Energy and Utilities Board
NERC	North American Electric Reliability Corporation
NMISA	Northern Maine Independent System Administrator
NPCC	Northeast Power Coordinating Council
NS IESO	Nova Scotia Independent Energy System Operator
PLNGS	Point Lepreau Nuclear Generating Station
PPA	Power Purchase Agreement
RIGS project	Renewable Integration and Grid Security project
SIS	System Impact Study

WITNESS ACKNOWLEDGE FORMS

Matter No. EL-002-2025

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

EXPERT WITNESS ACKNOWLEDGEMENT
(Rule 6.3)

In Relation to an Application by: New Brunswick Power Corporation

In Accordance with: Subsection 107(2) of the Electricity Act, SNB 2013 c. E-7 (the "*Electricity Act*" or the "*Act*")

I, Toshiki Bruce Tsuchida, of Boston, MA hereby confirm that:

1. I have been engaged by or on behalf of New Brunswick Power Corporation to provide evidence in relation to the above-noted proceeding before the New Brunswick Energy and Utilities Board.
2. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   a) to provide opinion evidence that is fair, objective and non-partisan;
   b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue in this proceeding.
3. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Dated the 19 day of September, 2025.

____
Toshiki Bruce Tsuchida

Matter No. EL-002-2025

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

EXPERT WITNESS ACKNOWLEDGEMENT
(Rule 6.3)

In Relation to an Application by: New Brunswick Power Corporation

In Accordance with: Subsection 107(2) of the Electricity Act, SNB 2013 c. E-7 (the "*Electricity Act*" or the "*Act*")

I, Jill Moraski of San Francisco, CA hereby confirm that:

1. I have been engaged by or on behalf of New Brunswick Power Corporation to provide evidence in relation to the above-noted proceeding before the New Brunswick Energy and Utilities Board.
2. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
    a) to provide opinion evidence that is fair, objective and non-partisan;
    b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
    c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue in this proceeding.
3. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Dated the 30 day of October, 2025.

Jill Moraski

Brattle

Énergie NB Power