

2026 Integrated Resource Plan

Powering a
Cleaner Future



Énergie NB Power



Acronyms

AAR – Alkali Aggregate Reaction
BTM – Behind the Meter
CCGT – Combined Cycle Gas Turbine
CCGT-CC – Combined Cycle Gas Turbine – Carbon Capture CER – Clean Electricity Regulation
CNSC – Canadian Nuclear Safety Commission
CO₂e – Carbon Dioxide Equivalent
CPI – Consumer Price Index
CT – Combustion Turbine
DSM – Demand Side Management
ELCC – Effective Load Carrying Capability
EIA – Environmental Impact Assessment
EV – Electric Vehicle
GDP – Gross Domestic Product
GHG – Greenhouse Gas
GWh – Gigawatt Hour
HDV – Heavy Duty Vehicles
HFO – Heavy Fuel Oil
IRP – Integrated Resource Plan
kW – Kilowatt
LCOC – Levelized Cost of Capacity
LCOE – Levelized Cost of Energy
LDV – Light Duty Vehicles
Li-ion – Lithium ion
MDV – Medium Duty Vehicles
MLAP – Mactaquac Life Achievement Project
Mt - Megatonnes
MW – Megawatt
MWh – Megawatt hour
NBEUB – New Brunswick Energy and Utilities Board
NB OBPS – New Brunswick Output Based Pricing System
NERC – North American Electric Reliability Corporation
NPCC – Northeast Power Coordinating Council
OATT – Open Access Transmission Tariff
OM&A – Operations, Maintenance and Administration
PLNGS – Point Lepreau Nuclear Generating Station
PPA – Power Purchase Agreement
PRR – Partial Revenue Requirement
REOI – Request for Expressions of Interest
RIGS – Renewables Integration Grid Security
ROE – Return on Equity
ZEV – Zero-Emission Vehicles

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Executive Summary

Electricity impacts everything we do. The direction we set today will impact the next generation. An affordable, clean and reliable electricity system is foundational to supporting the people and economy of New Brunswick in a changing energy landscape. This integrated resource plan (IRP) navigates uncertainty to provide various pathways to a resilient electricity system for the future.

Energizing our Future

For over 100 years, NB Power has provided safe and reliable power to the homes, businesses and institutions across New Brunswick. NB Power is proud to be New Brunswick's power company responsible for generation, transmission, and distribution. Electricity is deeply woven into our lives and our communities and the product we produce and sell is an enabler of environmental, social and economic development for New Brunswick.

In 2023, in response to the disruptive change that utilities are facing, NB Power released its *Strategic Plan 2023-2035 – Energizing our Future*. NB Power is on a path of transformation that is being driven by the pace of decarbonization, a competitive environment and evolving customer expectations, all while balancing costs as affordability concerns rise for New Brunswickers. As a company, we have established as our mission that we are passionate and committed to offering the best customer experience, ensuring energy security and accelerating a sustainable clean energy transition.

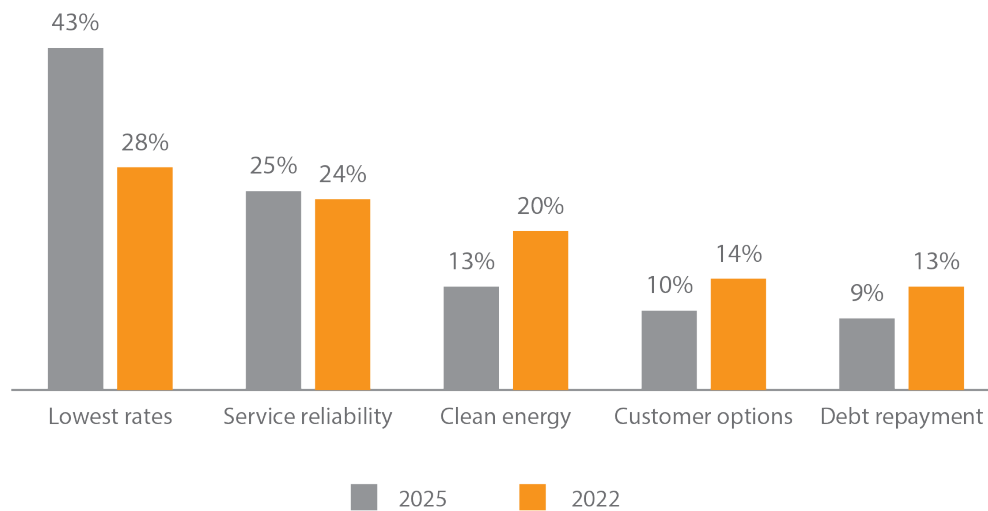
As the steward of the electricity system, NB Power is legislated to submit an IRP to the Government of New Brunswick every three years. The IRP covers a minimum of 20 years and follows the core principles of least-cost service, economic and environmental sustainability and risk management. It is important to balance these principles with NB Power's mandate to keep rates cost-effective and stable for New Brunswickers.

The *Electricity Act* requires the New Brunswick Energy and Utilities Board to consider the most recent IRP when making decisions on rate setting and major capital spending. While this plan supports that process, it does not include information on electricity rates or detailed financial statements. This information is included in NB Power's Three-Year Financial Plan, which, per the *Electricity Act*, must align with the most recent IRP.

The IRP is a strategic guide that provides several options to achieving NB Power’s long-term strategic objectives of energy security while accelerating a sustainable clean energy transition. The IRP does not recommend a specific portfolio to be approved. The purpose of the plan is to equip decision-makers and policy-makers with information when contemplating key decisions that will have an impact on the trajectory of the electricity system for generations to come.

One of the key elements in the development of the IRP is customer engagement. NB Power spent several months connecting with interested parties across the province including First Nations. The results of this engagement were loud and clear: lowest rates are the top priority, followed by reliability. As illustrated in Figure ES.1, NB Power asked New Brunswickers to tell us what is most important to them by assigning 100 percentage points to five different topics:

Figure ES.1: What is most Important to customers? - Engagement Survey



Planning for Uncertainty

From the current affordability crisis to the looming climate crisis, and the upheaval of the geopolitical landscape, we are living in uncertain times. In alignment with the core principle of risk management, NB Power takes a scenario-based approach to stress test the electricity system under different conditions. The approach establishes a flexible strategic framework with built-in optionality for NB Power to support decision-making in the face of uncertainty.

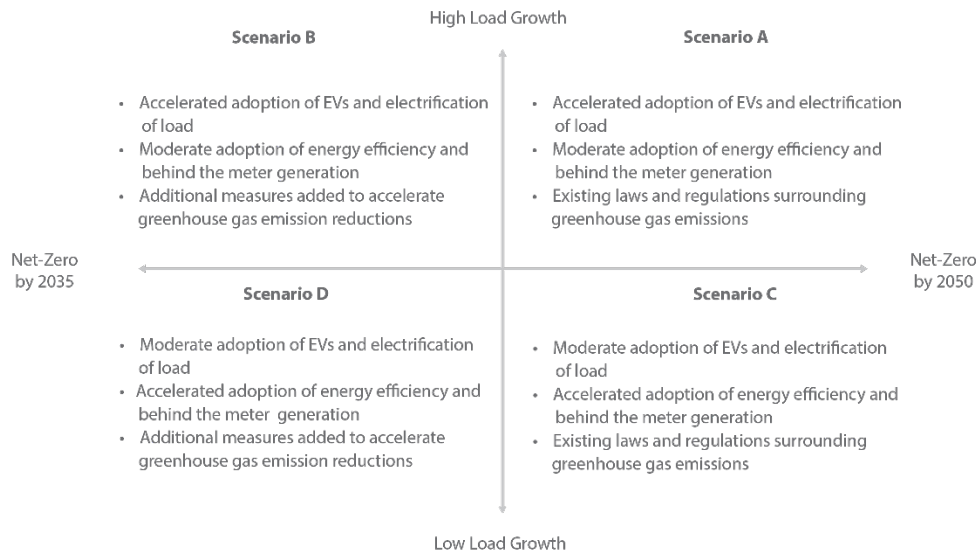
In the development of this IRP, NB Power identified two key uncertainties that will impact how we meet our long-term strategic objectives. These are the pace of decarbonization and the rate of load growth.

Electrification is driving load growth and putting pressure on utilities across North America. As such, NB Power views the rate of load growth with a high degree of uncertainty. Starting with the base load forecast, NB Power adjusted four different inputs to develop a high and low load growth forecast. The four inputs are the pace of electric vehicle (EV) adoption, the pace of load electrification, the impact of energy efficiency and the growth of behind-the-meter generation.

NB Power is committed to reducing carbon emissions from electricity generation while managing costs. Energy policy has been a key focus for governments at all levels as carbon policy continues to evolve. NB Power has constructed two different frameworks based on the pace of decarbonization. The net-zero 2050 scenarios model the existing laws and regulations in place surrounding greenhouse gas emissions whereas the net-zero 2035 scenarios present a more accelerated reduction of greenhouse gas emissions.

NB Power uses these four base scenarios to provide a robust view of different futures as shown in Figure ES.2. This helps identify ‘no-regrets’ actions and the signposts that signal pivotal decision points.

Figure ES.2: Scenario Summary



In addition to the four base scenarios, the IRP was developed by performing sensitivities to better understand how key events could shape New Brunswick's electricity system in the future.

With the growth in demand for electricity and the drive to decarbonize, nuclear has recently seen a resurgence in popularity. Exploring the different options for nuclear provides a complete picture of what the electricity system in New Brunswick could look like in the future, exploring the retirement of existing nuclear as well as the addition of new nuclear generating stations.

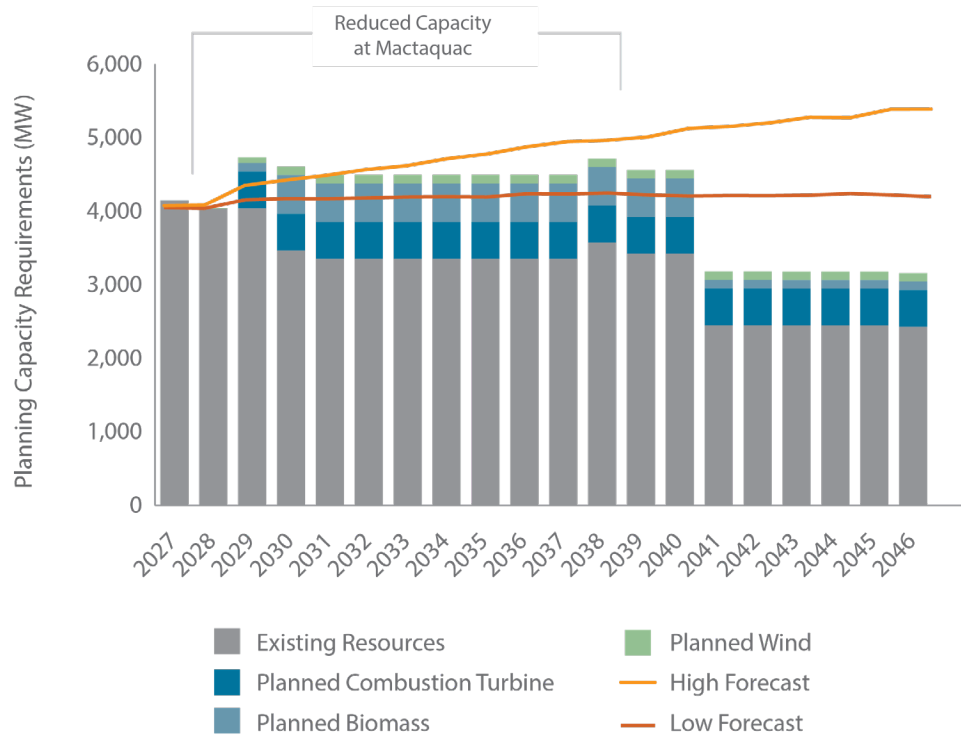
New Brunswick is one of Canada's most electrically interconnected provinces and uses those interconnections to drive value and contribute to keeping electricity in New Brunswick affordable. This IRP explores increasing the capacity of interconnections to better understand what role New Brunswick could play in being an energy hub for Atlantic Canada.

NB Power has had success in reducing its emissions significantly since 2005 and one of the predominate themes of this IRP is to explore different pathways to achieving a net-zero electricity system. A No Carbon Restriction Sensitivity will explore the cost and greenhouse gas emission impacts of achieving net-zero by providing the counterfactual, providing additional information when considering options on the pace of decarbonization.

Current Situation

NB Power owns and operates one of the most diverse generation portfolios in North America. However, this diverse fleet is aging and much of the infrastructure is approaching the end of its planned life. This IRP will be instrumental in providing insight on inflection points in the load and resource balance where resources reach their assumed end-of-life dates. Figure ES.3 shows NB Power's load and resource balance using existing generation fleet and contracts as well as planned generation developments.

Figure ES.3: Load and Resource Balance

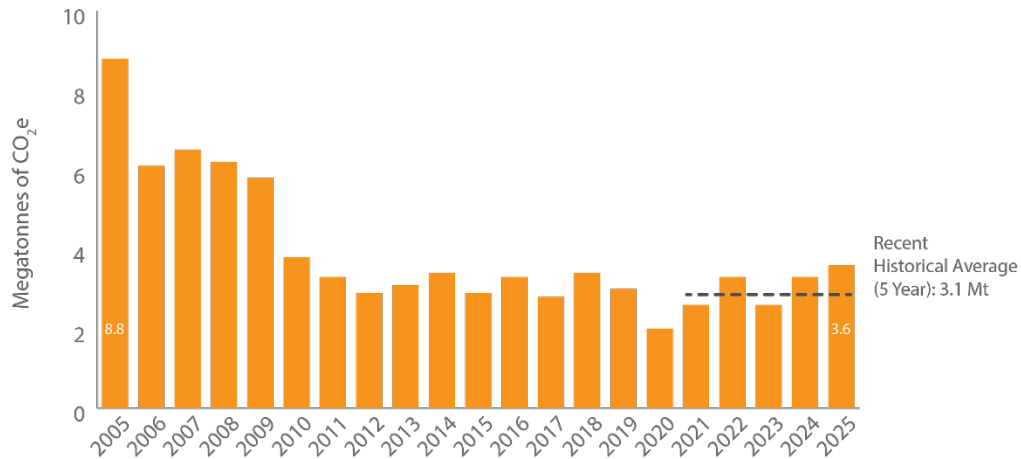


New Brunswick has a winter-peaking electricity system, which recently hit an all-time peak demand in 2023 of approximately 3,400 MW. The long-term load forecast to serve in-province energy and capacity requirements is heavily dependent on the winter season.

As a result of recent growth in load, NB Power has plans to expand its capacity by entering into agreements with industry experts to develop 702 MW of wind and 500 MW of combustion turbines by 2028/29. These agreements are included in all scenarios and sensitivities.

New Brunswick and NB Power recognize the importance of climate change and the province's role in supporting Canada's commitment to reducing greenhouse gas emissions. The province's climate change targets continue to affect the pace of decarbonization at NB Power and are considered in the scenarios examined in the IRP. As shown in Figure ES.4, NB Power continues to contribute to reducing the province's greenhouse gas emissions, having reduced our emissions by approximately 65 per cent from 2005 to today.

Figure ES.4: NB Power's Historical Greenhouse Gas Emissions 2005-2025^{1,2}



Results

The resource mix required to serve in-province energy requirements for the next 20 years calls for a combination of new wind, solar, batteries, demand response programs and combustion turbines. The difference between the expansion plans for the base scenarios is the timing and magnitude of the needs. Both batteries and combustion turbines play an important role in filling the capacity needs across all scenarios.

Figure ES.5 shows the total installed (nameplate) capacity for the Bayside extension, biomass, combustion turbines, battery storage, wind, solar and demand response without adjusting for each resource's contribution to reliability and energy security (i.e. effective load carrying capability or ELCC).

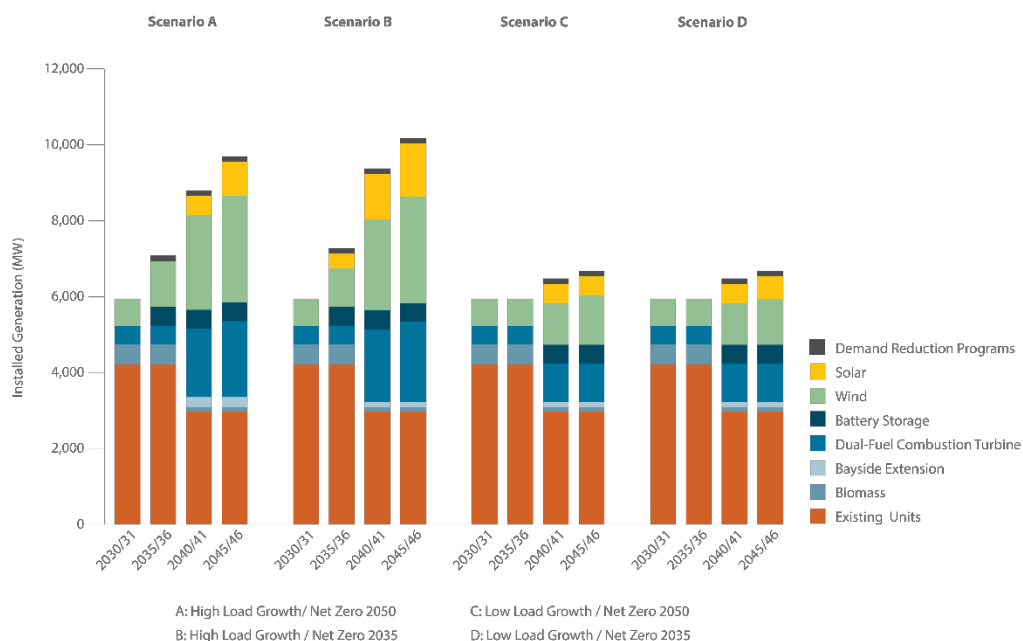
¹ Emissions for 2025 are estimated (unverified).

² Emission data based on internal data for NB Power owned facilities.

The largest expansion of resources occurs in 2040/41 based on the assumed end of life for the large generating resources, Belledune and Coleson Cove generating stations. The figure includes NB Power's current capacity as well as an additional 702 MW of wind and 500 MW of combustion turbines expected to be online in the next three years.

New wind and solar are always supported by the addition of some sort of dispatchable resource, typically batteries or combustion turbines, to help integrate the renewables and maintain reliability.

Figure ES.5: Installed (Nameplate) Generation by Scenario

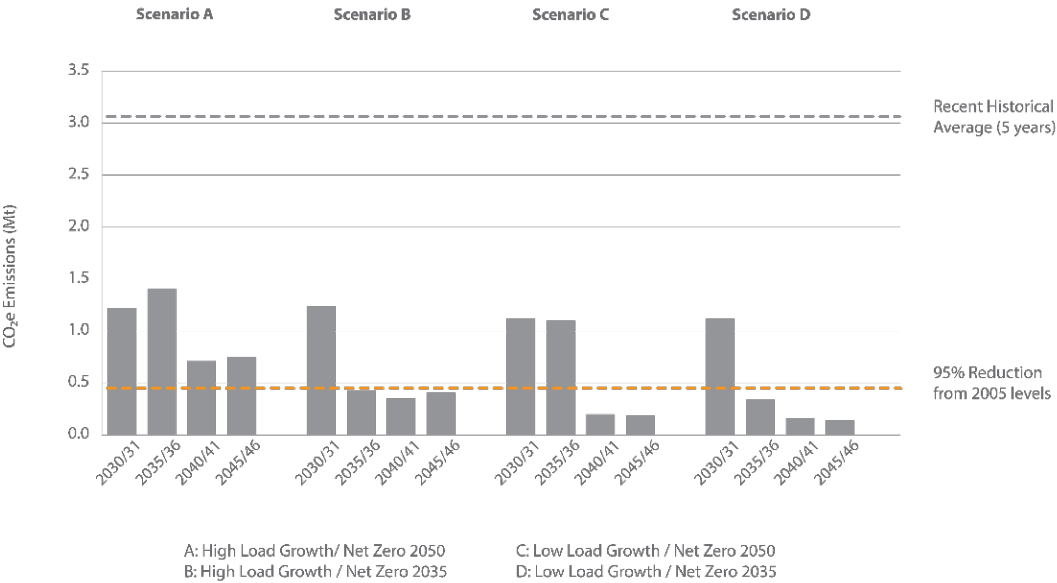


NB Power has made significant progress on reducing greenhouse gas emissions. Figure ES.6 shows the magnitude of the emission reductions already achieved based on a historical five-year average of 3.1 Mt, a reduction of approximately 65 per cent from 2005 levels.

While Scenario A does not achieve net-zero during the planning horizon, its annual average CO₂e emissions are well below one megatonne, an approximate 90 per cent reduction from 2005 levels and showing significant progress toward the net-zero 2050 goal.

The remaining Scenarios B, C and D shows emission reductions of 95 per cent from 2005 levels. As emissions drop below one megatonne and approach net-zero, remaining emissions could be offset either through converting to renewable fuel, such as biomass, biodiesel and renewable natural gas, purchasing carbon offset credits or paying a carbon tax to the government, which could then be invested in carbon reduction initiatives in other areas of the economy.

Figure ES.6: Greenhouse Gas Emissions by Scenario (CO₂e)



The cost to serve in-province electricity customers (i.e. partial revenue requirement³ or PRR) is highly dependent on the trajectory of load growth in the province. Figure ES.7 normalizes the PRR for in-province energy sales volume, showing the average cost to serve in each year.

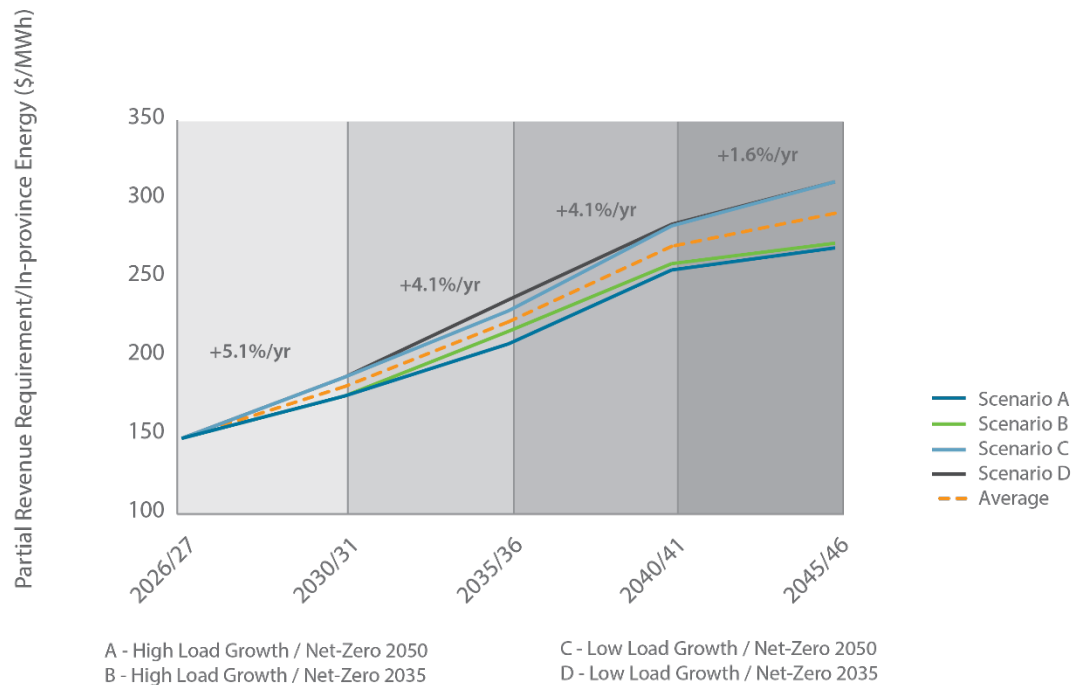
Overall, the average cost to serve increases most heavily in the near-term driven by the Federal Government Regulation to transition away from coal, increases in carbon pricing as well as improving financial sustainability to help improve NB Power's debt to equity ratio.

The Mactaquac Life Achievement Project (MLAP) begins to impact the results in the 2030s, putting upward pressure on costs in those periods. In 2035/36 and beyond, the average costs are higher for the net-zero 2035 scenarios as expected.

The High Load Growth Scenarios have less overall pressure on the average cost to serve. It should be noted that the majority of the growth is in high load factor industrial load, which has a lower cost to serve today and accordingly lower rates, so a lower average cost to serve will not necessarily lead to lower rates.

³ Partial revenue requirement (PRR) is calculated as the total revenues to be collected through rates from in-province customers. This is also net of any miscellaneous or export revenues that help to offset the cost to New Brunswick customers.

Figure ES.7: Average Cost to Serve (PRR /In-Province Energy Requirements) by Scenario⁴



Common Actions

NB Power is currently undertaking critical investments in our energy future. These include power purchase agreements for 702 MW of new wind generation, 500 MW tolling agreement for new dual-fueled combustion turbine capacity, a conversion of Belledune to biomass, and investments in a new transmission line between New Brunswick and Nova Scotia.

Common actions across the base scenarios provide insight on no-regret decisions that NB Power should consider pursuing. Table ES.1 contains a summary of future projects that are needed in all base scenarios. These projects provide value to the system and are not sensitive to the key uncertainties identified like load growth and the pace of decarbonization. In the case of the Bayside Generating Station extension, at a minimum the gas turbine will continue to operate beyond the 2038 assumed end of life date.

⁴ Percentage increases are shown for the average of the four scenarios and fully span the period between years. For example, the 5.1 per cent annual increase between 2026/27 and 2030/31 is equivalent to a 22 per cent average increase over four years.

Table ES.1: Summary of Common Actions Across Base Scenarios

Installed Generation	Technology
410 MW	Belledune biomass
150-270 MW	Bayside extension
500 MW	Batteries
146 MW	Demand response
400-2,100 MW	Wind
500-1,500 MW	Solar
500-1,600 MW	Combustion turbines

In addition to the common actions across all base scenarios, it is worthwhile to highlight the additional requirements that are included in both scenarios A and B but not included in scenarios C and D. This comparison of the high load growth scenarios to the low load growth scenarios helps provide insight into the most economic options for responding to growth.

They include

1. acceleration of battery storage
2. acceleration of demand response programs
3. higher total volume and acceleration of wind
4. higher total volume and acceleration of solar
5. higher total volume of acceleration of combustion turbines

Notably, the total capacity of demand response and battery storage is not impacted by the pace of load growth, just the timing, with needs arising earlier in the high load growth scenarios.

The timelines under which resources can be procured and built also must be considered, with the lead times in the range of three to five years at a minimum, with considerably longer lead times in recent years due to supply chain pressures for certain technologies.

The Future of Nuclear

Nuclear generation has a long history in New Brunswick. The existing Point Lepreau Nuclear Generating Station provides tremendous value to New Brunswick's electricity system. To better understand the future of nuclear, the 2026 IRP explores the options of early retirement, life extension as well as refurbishment and or a new build.

Life extensions of similar facilities have been successful and extending the life would bring about \$900 million in annual value to the electricity system. The estimated annual costs of extension are currently estimated at closer to \$600 million. A decision to extend the life at PLNGS would require an application and approval with the Canadian Nuclear Safety Commission (CNSC). NB Power is currently working towards completing the necessary engineering studies and analysis that could support this extension application to the CNSC.

New nuclear brings opportunity by providing large volumes of reliable non-emitting electricity to New Brunswick. Growing New Brunswick's nuclear footprint could bring economies of scale and enable opportunities for regional partnerships. There are still technical, economic and policy considerations to understand before making a decision to commit New Brunswick to new nuclear generation.

When nuclear is retired and not replaced, significant amounts of renewables and combustion turbines are required to fill the gap. Without nuclear, carbon emissions increase and three out of four scenarios do not achieve net-zero before 2050 despite additional carbon restrictions, showing the benefits nuclear generation brings to decarbonizing the electricity sector.

Strategic decisions surrounding life extension, refurbishment or a new build are required to be made within the next five-year period, which dictates the need for a business case to be developed within the next three-year period.

New Transmission

New transmission infrastructure between New Brunswick and neighbouring jurisdictions could create opportunities to purchase more energy as well as increase export sales. No specific transmission project design or engineering has been completed on this opportunity. However, New Brunswick has a relatively small electricity system and the cost is likely in the range of multiple billions of dollars.

The value of this proposition is likely to increase when forming strategic partnerships with neighbouring areas to transmit energy to the region. Further consideration for additional value streams or other sources of funding for transmission infrastructure as well as more specific project cost estimates are needed to refine this potential opportunity.

Existing Greenhouse Gas Laws and Regulations

The existing laws and regulations in place surrounding greenhouse gas emissions lead to reductions in CO₂e emissions and higher costs. The phase-out of coal at Belledune drives both in the early term. By the 2040s, after the assumed retirements for Belledune and Coleson Cove generating stations, emissions reduce without any regulatory signal, even achieving the net-zero emission reduction target in the low load scenario.

Overall, the existing laws and regulations will result in reducing emissions by 34-29 Mt over the 20-year planning horizon at a cost of \$104-110/tonne of CO₂e reduced. These results show that current carbon laws and regulations are effective in achieving the goal of reducing CO₂e emissions and put New Brunswick on a trajectory to achieve net-zero by 2050.

Final Word

NB Power is committed to its customers and meeting their electricity needs in a safe, reliable way. Customers want NB Power to prioritize lowest rates, and NB Power's focus on operational excellence will improve our ability to deliver cost-effective reliable service for our customers. As we consider the cost pressures and trade-offs surrounding load growth and the speed of decarbonization in the 2026 IRP, we maintain our focus on achieving operational excellence while exploring many potential pathways, evaluating opportunities and incorporating no-regret activities along the way.

In such times of uncertainty, it is critical now more than ever that NB Power has an adaptable integrated resource plan to set its foundation to respond to any changes in laws, regulations or market conditions that may affect the future of electricity in New Brunswick. This IRP is the foundational groundwork on which NB Power will weigh critical decision points that may arise.

1. Introduction

1.1. Our Commitment to New Brunswick

Because energy is deeply woven into the fabric of daily life, NB Power remains a constant presence in every community across the province, providing a critical service available around the clock. We recognize that our role extends far beyond the grid and our operations are primary drivers of New Brunswick's environmental, social and economic development. This responsibility anchors our commitment to delivering an energy future that is affordable, reliable and sustainable.

As a provincial Crown Corporation, the Government of New Brunswick is the sole owner and shareholder of NB Power. As such, the Government of New Brunswick has entrusted NB Power with the responsibility for managing the electricity system in New Brunswick. For over 100 years, NB Power has been responsible for the generation, transmission and distribution of electricity that powers homes, businesses and communities in the province. NB Power remains at the heart of our province's history and our identity.

Every employee at NB Power comes to work with a mission and vision to enhance the lives of New Brunswickers. Our employees are committed to serving the province and our customers today and in the future.

1.2. Our Commitment to Indigenous Relations

NB Power respectfully acknowledges that New Brunswick is situated on the unceded and unsurrendered territories of the Wolastoqey, Mi'gmaw and Peskotomuhkati peoples. We seek to repair and rebuild meaningful relationships with Indigenous peoples and honour these lands which hold the hopes of future generations.

What we experience today is based on decisions that were made in the past. NB Power acknowledges the impact it has had on the land and resources in New Brunswick. We honour the deep connection Indigenous peoples have with this land and the weight of our shared responsibility to future generations. NB Power values its relationship with First Nations communities and is committed to working together to build an electricity system that will serve First Nations, and all New Brunswickers, for generations to come.

1.3. Our Strategic Plan

Energizing Our Future



OUR VISION

We enhance lives by providing clean, competitive and reliable energy solutions.



OUR MISSION

We are passionate and committed to offering the best customer experience, ensuring energy security and accelerating a sustainable clean energy transition.

OUR VALUES



SAFETY AT HEART

We are committed to the safety of every employee and member of the public through

- planning safety into the work
- following the rules
- being a leader in safety
- reporting so we can all get better
- having courage
- saying no to unsafe work



CARE FOR OUR TEAM

We care for our team. We are open, honest and transparent with each other to build trust. We embrace diversity, creating an inclusive culture that supports employee well-being, encourages continuous learning and drives high performance.



CARE FOR OUR CUSTOMERS

We care for our customers. We put their experience at the centre of everything we do. We are committed to delivering relevant and valuable solutions. We act with integrity and do what we say we are going to do.



CARE FOR OUR FUTURE

We care for our future. We work with customers and communities to explore and deliver on their evolving energy needs while being environmentally responsible for future generations. We are curious and open to new ways of working.



CARE FOR OUR CORE

We take care of our nuclear core. We understand the unique nature of the nuclear core and are committed to make Nuclear Safety the overriding priority.

1.4. What is an Integrated Resource Plan and why do it?

The Integrated Resource Plan (IRP) is a robust, long-term picture of New Brunswick's energy future, providing a 20-year supply and demand resource plan to guide NB Power's short- and long-term decisions on resource development.

Every three years, as required by the *Electricity Act*, NB Power refreshes the IRP to reflect the changing energy landscape and customer expectations. The IRP must cover a minimum of 20 years and be developed in accordance with the principles of least-cost service, economic and environmental sustainability and risk management.

Once updated, NB Power submits the IRP to the Government of New Brunswick for approval and then submits it to the New Brunswick Energy and Utilities Board (NBEUB) following that approval.

The *Electricity Act* requires the NBEUB to consider the most recent approved Integrated Resource Plan when making decisions on rate setting and major capital spending.

For NB Power, the IRP is an essential strategic guide to managing the cost, policy requirements and risk of developing supply options to provide reliable electricity to customers. It identifies key points in time where NB Power will need to make significant decisions and provides possible outcomes of those decisions based on high-level assumptions and information available at the time.

The IRP does not dictate a definitive future or course of action, but rather establishes a flexible framework with built-in optionality for NB Power to support decision-making in the face of uncertainty. Employing a scenario-based methodology, the IRP provides signposts on what to look for and what actions to take when a specific uncertainty occurs, even if it does not match the exact timing identified in the IRP.

1.5. Methodology

The New Brunswick *Electricity Act* establishes that the NB Power IRP will be developed using the three tenets of least-cost service, economic and environmental sustainability and risk management.

The tenet of least-cost planning directs NB Power to ensure that the IRP meets all reliability and safety standards, regulations and government legislation with a plan that has the lowest system cost.

The tenet of economic and environmental sustainability ensures NB Power's plan is economically as well as environmentally sustainable. NB Power is making progress toward improving its debt-to-equity ratio over the period covered by the IRP. Additionally, NB Power needs to meet its requirements in an environmentally responsible way while adhering to least-cost planning.

Finally, the tenet of risk management directs NB Power to consider all relevant types of risk. The IRP considers many different risks and assumptions based on the best information available at the time. Many key assumptions are not within NB Power's control and are affected by external factors such as markets, supply chains and government laws and regulations. Because many assumptions are subject to factors outside of NB Power's control, NB Power uses a scenario-based approach to planning to create a suite of base scenarios that cover four likely futures. The IRP then performs sensitivity analysis on the base scenarios where key assumptions are changed. This allows NB Power to identify the system and financial impacts related to key assumption changes. All these scenarios help NB Power and IRP users to understand many of the risks and how they may affect the IRP.

NB Power created a matrix of four scenarios based on dual axis of the load growth and the direction of the laws and regulations surrounding greenhouse gas emissions. In the 2023 IRP we used the pace of electrification, which can be compared to load growth, and the pace of technology development. The 2023 IRP results showed that the pace of technology development was less impactful than the laws and regulations surrounding greenhouse gas emissions applied to the IRP model. For this reason, NB Power has changed the axis to the timing of when the electricity industry is to be decarbonized.

Consistent with the *Electricity Act*, this IRP uses the least-cost-of-service and greenhouse gas emission impacts as key metrics. Least-cost-of-service is measured by taking the present value of the estimated annual partial revenue requirements⁵ over 20 years for each expansion plan. This helps inform the long-term cost implications of the different scenarios and sensitivities. Emission impact is determined by calculating the total emission output for each plan over the 20-year planning horizon.

⁵ Partial revenue requirement is defined as the total revenue to be recovered from in-province electricity customers. This differs from traditional revenue requirement in that it is reduced by miscellaneous and export revenues.

NB Power begins IRP development by engaging with First Nations, New Brunswickers and other interested parties to identify key priorities. In 2025 NB Power had over 10,000 individual engagements with parties across New Brunswick at home shows, one-on-one meetings and via an on-line survey. The level of engagement increased by 61 percent compared to the previous IRP. Engagement timing for past IRPs coincided with the late summer / early fall period. Changing the timing to coincide with late spring increased the volume of engagement with all parties.

Table 1.1: Summary of Public Engagement

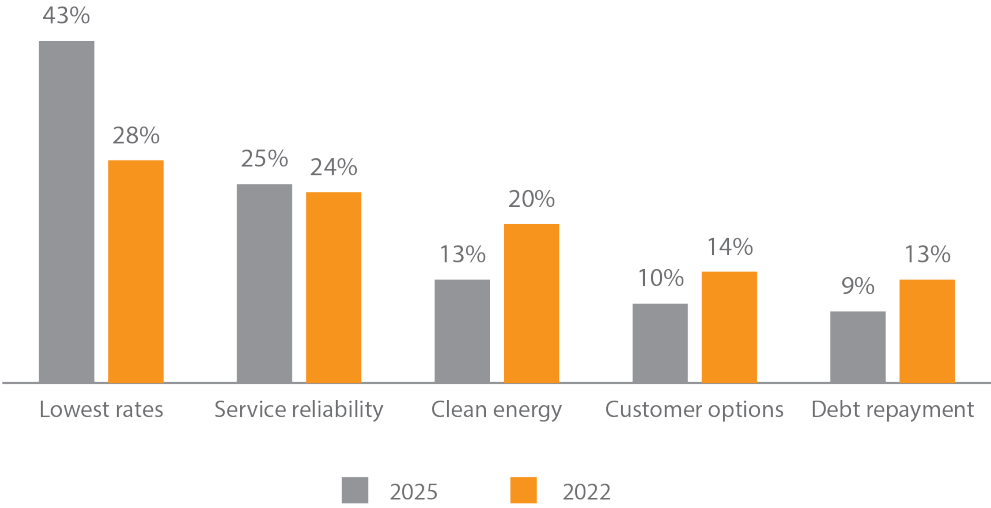
Engagement Format	Number of Engagements
Community events, face-to-face conversations and one-on-one meetings	258
Online survey	9,899
Total	10,157

Results from the 2025 engagement activities identified lowest rates as the highest priority, followed by reliability, the environment, customer options and debt repayment. Based on the survey results, New Brunswickers have indicated that a transition to a clean energy future needs to minimize impacts on rates and the economy. With an eye to affordability, respondents expect NB Power to promote energy efficiency and offer products and services that assist them in managing usage and lowering costs.

Details on the results of the public engagement survey can be found in the *What Was Heard* Report.⁶

⁶ New Brunswick Power Corporation (June 2026). *What Was Heard Report*

Figure 1.1: What is most important to customers? - Engagement Survey



2. Current Situation

NB Power has a diverse mix of generation resources and power purchase agreements. The utility serves the electric needs of the province with nuclear, hydro, wind, biomass, solar, natural gas, oil and coal generating resources.

In a typical year, NB Power supplies New Brunswicker's energy needs with 75 per cent carbon-free energy (including nuclear generation) and consistently exceeds its renewable portfolio standard requirement to supply 40 per cent of in-province electricity sales from renewables.

This diverse mix of generation capability is key to meeting New Brunswick's electricity requirements well into the future, though additional new resources will be required to meet load growth as well as to replace units that are expected to reach their end of life.

In addition to the generation resources, NB Power also has many interconnections with neighbouring utilities in Québec, Prince Edward Island, Nova Scotia and New England. The interconnections provide NB Power with flexibility to import electricity to offset higher cost generation, export surplus energy and increase system reliability.

The purpose of this section is to explore the current resources that make up the electricity system in New Brunswick. The IRP looks at the existing system resources that can have an impact on planning including generation and transmission as well as the role of customer programs for behind-the-meter generation and demand response.

Figure 2.1: System Map



The current net generation capacity and power purchase agreement portfolio, as well as other statistics of the NB Power system, is provided in Table 2.1. The IRP assumes the current resources are available as needed to serve the in-province energy requirements.

Table 2.1: Existing NB Power Net Generating Capacity and Other Statistics⁷

Generating Capacity Thermal			Power Purchase Agreements (PPAs)	
Coleson Cove	972	MW	Kent Hills (Wind)	167 MW
Belledune	467	MW	Caribou Mountain (Wind)	99 MW
Bayside	270	MW	Lameque (Wind)	45 MW
Total Thermal	1,709	MW	Wisokolamson Energy (Wind)	18 MW
Generating Capacity Hydro			Wocawson Energy (Wind)	20 MW
Mactaquac	668	MW	Neweg (Wind)	25 MW
Beechwood	112	MW	Grandview (Natural Gas)	90 MW
Grand Falls	66	MW	Twin Rivers (Biomass)	39 MW
Tobique	20	MW	Irving Pulp & Paper (Biomass)	33 MW
Nepisiguit Falls	12	MW	AV Nackawic (Biomass)	26 MW
Sisson	9	MW	AV Cell (Biomass)	21 MW
Total Hydro	887	MW	St. George (Hydro)	15 MW
Generating Capacity Nuclear			Edmundston (Hydro)	9 MW
Point Lepreau Nuclear Generating Station	663	MW	Tinker (Hydro)	33 MW
Renewables			Other Renewables	45 MW
Shediac Solar Farm	2	MW	Total PPAs	685 MW
Combustion Turbines			Number of Lines	
Millbank	397	MW	Distribution Lines	22,069 km
Ste. Rose	99	MW	Transmission Lines	6,898 km
Grand Manan	22	MW	Exporting and Importing Capacity ⁸	
Total Combustion Turbines	518	MW	Import Capacity	2,514 MW
Total Generating Capacity			Export Capacity	2,462 MW
Thermal	1,709	MW	Number of Customers	
Hydro	887	MW	Direct Customers	399,525
Nuclear	663	MW	Indirect Customers	47,619
Renewables	2	MW	Total Customers	447,144
Combustion Turbines	518	MW		
Total Generating Capacity	3,779	MW		

⁷ Existing generating capacity is based on installed capacity of resources connected to NB Power system as of March 31, 2026

⁸ Based on transmission planning studies for total transfer capability during the summer period.

2.1. Existing Generation Resources

NB Power currently operates a diverse fleet of generating assets. Many of the generating units are aging and significant end-of-life decisions will need to be made. The IRP reviews the current status of the system and presents possible options for life extension or retirement of these current NB Power assets.

Mactaquac Generating Station

The Mactaquac Generating Station is located on the St. John River, approximately 20 km west of Fredericton, New Brunswick. The Station is the largest hydroelectric generation facility in the Maritimes, provides many grid services and is an essential resource to the reliable operation of the electrical grid.

NB Power commissioned the Station in 1968, with a designed service life of 100 years, and an original estimated end of service life date of 2068.

The concrete structures at the station are affected by Alkali Aggregate Reaction (AAR), which has resulted in an overall decrease in the 100-year original design service life of the facility and requires extensive maintenance to maintain the integrity of the physical structures.

Condition assessments have determined that the concrete structures and major equipment will reach the end of their useful service life by approximately 2032 and will require either major rehabilitation or replacement.

Figure 2.2: Mactaquac Generating Station



In 2016 and again in 2024, NB Power recommended proceeding with the Mactaquac Life Achievement Project (MLAP) to rehabilitate the Station and achieve the original design life of 2068. NB Power has conducted extensive technical studies and stakeholder engagement and in July 2023, NB Power submitted the project for review under New Brunswick's Environmental Impact Assessment (EIA) legislation. NB Power received EIA approval in May of 2025. NB Power has been refining engineering designs and cost estimates, mobilizing project resources, issuing requests for proposals for the turbine and generator work as well as the civil works.

Pending a final investment decision from the provincial government, the life achievement project execution is expected to begin in 2027. Over the course of the 12-year project, the turbine and generator units will be replaced one at a time, allowing the generating facility to continue to operate at reduced output throughout the duration of the project. The IRP assumption is that generator outages will start in 2028 and continue through to 2038. The base assumption for the Mactaquac generating facility in all scenarios for the 2026 IRP is the pursuit of the Mactaquac Life Achievement Project.

Bayside Generating Station

The Bayside Generating Station is a natural gas-fired combined cycle power plant located in Saint John at the former Courtney Bay site. The original Courtney Bay generating plant at that site was commissioned in the 1960s. In 1999, a new gas turbine was installed and combined with one of the former Courtney Bay units into the Bayside Generating Station. In 2023, NB Power commissioned a new natural gas turbine that increased the unit's efficiency. Bayside's assumed end of life is established as 2038 based on the steam turbine economic life, but the gas turbine could continue to operate until 2048, to achieve a more typical 25-year life.

The base assumption for Bayside is that by 2038, NB Power will need to make a decision on the plant. The model provides options to end operation at Bayside, continue operations by investing capital to convert the plant to a simple cycle facility or invest capital to refurbish the steam turbine and continue to operate the plant as a combined cycle facility. For options where the facility continues to operate beyond 2038, the new retirement assumption is 2048 based on a 25-year typical life of a gas turbine. The life-cycle station costs, fuel and related carbon costs are accounted for in all options.

Belledune Generating Station

The Belledune Generating Station, commissioned in 1993, is the only coal facility in NB Power's diverse system. The facility provides a low-cost source baseload energy and reliable supply to meet capacity requirements.

Based on current Federal regulations, NB Power is required to phase out coal generation by 2030. In response to this regulation, NB Power began in 2023 testing the viability and economics of replacing coal with biomass at Belledune as early as 2029. Initial testing has confirmed that fuel conversion is technically feasible.

NB Power issued a Request for Expressions of Interest to evaluate sources for required biomass and continues to plan the engineering work that will be needed to convert Belledune to use biomass. The base scenarios in the 2026 IRP assume that the Belledune Generating Station will convert to biomass during the summer outage in 2029 to meet the requirement to be off coal by 2030. Belledune's assumed end of useful life is 2040/41. An analysis on options beyond end of life are not included in this IRP but may be reviewed in the future after a successful conversion to biomass is complete.

Point Lepreau Nuclear Generating Station

In 1974, NB Power, with support from the provincial and federal governments, endeavoured to build a nuclear generation station at Point Lepreau. In 1983, the Point Lepreau Nuclear Generating Station began commercial operation. It provided many benefits to New Brunswick's electricity sector by being a major source of energy and capacity without problematic air-borne effluents like sulfur and nitrogen oxides, mercury and particulate matter. Additionally, the nuclear industry brought economic benefits and many jobs to the province.

In 2010, the station was due for either retirement or a refurbishment of the key reactor components. In 2008, the province of New Brunswick gave NB Power a directive to conduct a refurbishment at the facility. This was a first-of-a-kind project and brought with it many challenges associated with several unknowns. The station was out of service for fifty-five months before returning to service in November 2012.

The plant life of a nuclear generating station is based on the number of equivalent operating hours. Point Lepreau Nuclear Generating Station is currently licensed to operate for 210,000 hours, which it is estimated to achieve by mid-2042. NB Power's sensitivity modelling sets the threshold at March 31, 2042. There are considerable uncertainties in the end-of-life plans for the station that require decisions. The 2026 IRP considers all options including

1. retirement of the station
2. life extension of the station
3. refurbishment of the station

With respect to life extension, other CANDU reactors in Canada have operated beyond the 210,000 hours threshold. NB Power will conduct feasibility and engineering assessments to determine if the plant can safely operate beyond the threshold. For the 2026 IRP, the base case scenarios assumes a life extension of Point Lepreau Nuclear Generating Station. This would extend the license to operate up to 235,000 operating hours with an assumed end of life occurring at 2047/48, beyond the planning horizon of this analysis.

Sensitivities around early retirement as well as refurbishment or new nuclear are considered and analyzed in Section 6.

Coleson Cove Generating Station

The Coleson Cove Generating Station is the largest thermal plant in New Brunswick with a capacity of 972 MW (net) located west of Saint John and began commercial operation in 1976. It has three equally sized units (324 MW) all fueled by low sulfur heavy fuel oil (HFO). Coleson Cove's assumed end of useful life is 2040/41. Neither life extension nor fuel conversion at this facility was considered in the analysis due to the age of the asset.

Existing Power Purchase Agreements

NB Power currently has power purchase agreements for 685 MW of installed generation in the province, including 595 MW of renewables. The IRP assumes that these PPAs are renegotiated at market rates when they expire.

2.2. Generation Resource Assumed Retirements

For accounting purposes, each generating station is depreciated consistently with its assumed technical useful life based on typical experiences for that type of facility. Power purchase agreements have set contract terms and are generally tied to the useful lives of the contracted facilities. In actual practice, retirements are dependent on a technical and economic evaluation for each unit as it approaches the end of its useful life. In this IRP, retirement assumptions are based on an end of useful life approach, with consideration of a reasonable life extension period that allows the facility to continue operations.

The generating stations assumed end of useful life are shown in Table 2.2. It is assumed that all hydro facilities will continue to operate through the planning horizon. All PPAs are assumed to be extended at competitive market prices. Combustion turbines at Millbank, Ste. Rose and Grand Manan are assumed to have life extensions to meet continued capacity needs. The Clean Energy Regulation (CER) will restrict the operation of fossil fuel generating stations but will not force generating stations to retire. Consideration of life extension potential is made through studies conducted by NB Power engineering experts and associated economic analyses.

Table 2.2: Retirement Assumptions for IRP Modelling⁹

Resource	Fuel Type	Net Capacity (MW)	Assumed End of Life
Grand Manan ¹⁰	Diesel	26	2030/31
Bayside	Natural Gas	270	2037/38
Belledune ¹¹	Coal/Biomass	467/410	2040/41
Coleson Cove	Oil	972	2040/41
Point Lepreau Nuclear Generating Station	Uranium	663	2047/48

2.3. Proposed Generating Capacity

The growing demand and anticipated generating station retirements require NB Power to secure new energy and capacity contracts over the course of the Integrated Resource Plan. NB Power has agreements for an additional 1,269 MW of contracted installed capacity (not adjusted for contribution to system reliability and energy security) to be online by 2028/29.

⁹ Millbank and St. Rose are scheduled to undergo capital upgrades that will extend their asset life out to approximately 2050. Specific new end of life dates will be identified in the coming years.

¹⁰ Grand Manan's capacity is assumed to be replaced-in-kind to maintain local reliability in the Fundy Isles.

¹¹ Coal is phased-out at Belledune in 2030

Table 2.3: Proposed Agreements ¹²

Fuel Type	Installed Capacity	Commercial Date
Wind	702 MW	2027 and 2028
Large Industrial (biomass) ¹³	117 MW	2028/29
Combustion Turbine ¹⁴	500 MW	2028/29
Total Contracted Installed Capacity	1,269 MW	

Proposed Combustion Turbine Project

In 2023, NB Power experienced a new record winter high load period and identified that demand had increased faster than forecast. In response to the growth in customer needs, a resource adequacy assessment was performed and determined the utility was deficient of capacity to meet the growing customer demand. NB Power considered several factors, such as aging infrastructure, tightening of resources in neighboring areas, and plans to expand variable renewable generation supplies in New Brunswick, ultimately initiating a procurement process to acquire new generating resources for capacity. As a result, NB Power entered into an agreement in 2024 to purchase capacity and energy from a 500 MW dual-fueled combustion turbine facility located in southeastern New Brunswick.

The proposed project is referred to as the Renewables Integration Grid Security (RIGS) project and was filed with the EUB for approval in 2025/26. The facility will be able to generate electricity from gaseous as well as liquid fuel. Dual-fueled capability is needed to ensure cost diversity and fuel reliability should one of the sources be unavailable. Natural gas will be the primary fuel source as for much of the year it is cheaper and has lower carbon emissions. Liquid fuel stored and available on site will ensure that NB Power is not completely exposed to the risk of price and availability presented by natural gas during periods of high demand. The dual-fuel capability maintains optionality for potential future opportunities for transitioning to renewable fuels such as renewable natural gas or biodiesel.

¹² Proposed generating capacity is based on anticipated installed nameplate of resources that are expected to connect to NB Power system based on contracts signed as of January 1, 2026

¹³ The Large Industrial (biomass) generation is 117 MW with an offsetting load increase associated with the project.

¹⁴ Subject to NB EUB approval, contract of 100 MW to be designated for export with 400 MW available to serve in-province requirements.

The RIGS facility will provide grid services that are essential to support an increased penetration of wind and solar generation in the coming years. The facility will be able to turn on and off quickly and provide reliable electricity as needed, should it be for a few hours or consecutive days. RIGS will also offset some generation at Belledune and Coleson Cove as it will be more flexible and have lower operating must-run volumes. The increased ability to integrate wind and solar along with reduced operation at other thermal generating stations will contribute to NB Power's goal of reducing carbon emissions. The base scenarios assume that 500 MW of capacity from the RIGS facility is available in 2028/29.

2.4. Behind the Meter Generation

NB Power has a program that allows customers to connect behind the meter renewable energy from sources such as solar, small hydro or wind to the grid. A smart meter with bidirectional capabilities records both the electricity delivered to the customer and any excess electricity NB Power receives back from the customer's generation unit after self-supply, allowing New Brunswickers to offset their energy consumption.

NB Power has 27 MW of connected behind-the-meter generation under the net metering program as of January 1, 2026. This is expected to grow considerably over the next twenty years, with forecasts ranging from 300 to 700 MW by 2046. Refer to Appendix F for detailed information regarding behind the meter forecast.

NB Power also has an embedded generation program for larger general service or industrial customers to connect larger generators to the grid. There is currently 16.3 MW installed under the embedded generation program.

2.5. Transmission Resources

NB Power's transmission system is made up of 6,900 kilometers of transmission lines, terminals and control equipment. It's designed to provide reliable energy to New Brunswick customers and allows the utility to export and import energy to and from neighbouring utilities.

New Brunswick's transmission system is a small section of the Eastern Interconnection, a much larger bulk transmission system which spans from Central Canada to the Atlantic coast, excluding Québec and in the US from the Midwest, to the Atlantic and the Gulf including Florida and excluding Texas. Interconnected transmission lines and an Open Access framework are used to transfer electricity from one jurisdiction to another under strict rules that maintain open, fair and reliable service.

Having strong interconnections with neighbouring systems is very important to NB Power. New Brunswick is well positioned with direct interconnections to Québec, Prince Edward Island, Nova Scotia and New England. New Brunswick is a net importer of energy and relies heavily on neighbouring areas to meet annual in-province energy requirements. The interconnections also support the system with direct and indirect contributions to capacity reserves, decreasing the need for additional generation capacity to be committed and online at any given instant to serve customers, which results in lower costs for New Brunswickers.

NB Power regularly assesses the transmission system to ensure it meets reliability standards and provides benefits to New Brunswickers and other customers.

While meeting adequacy requirements, in-province and customer load requirements place strain on the transmission system. NB Power is aware of transmission constraints within some parts of New Brunswick and is looking at solutions to address these issues, including

- additional transmission infrastructure
- targeted demand reductions
- strategically locating any new generation

2.6. New Transmission Requirements

New transmission requirements are driven by several potential factors, including

- the need to connect new generation or energy storage resources
- generator retirements
- in-province load growth
- import and export requirements
- system reliability
- industry reliability standards
- customer-driven requests
- system support to integrate larger volumes of variable renewable generation

Future decisions around the Belledune and Mactaquac generating stations have a significant impact on transmission requirements to maintain system reliability as these resources provide critical grid services. As such, for the first time, the transmission costs have been included in the integrated resource planning, a significant step forward in integrated planning as compared to the development of past IRPs.

The growth of and reliance on variable renewable generation is also having an impact on transmission reliability and requirements. As more wind and solar generation are added to the grid, additional resources such as synchronous condensers and static VAR compensators will be needed to ensure grid stability. The cost of these transmission reinforcement additions are included in the assessment of these technologies.

Resources such as RIGS have built-in synchronous condenser capability to provide the essential services such as load following, dynamic reactive support and system inertia which are key to operating a reliable system. This is particularly important in the southeastern area of the province where the transmission system faces both grid congestion as well as a high concentration of renewable generation.

NB Power and Nova Scotia are currently working on twinning the 345 kV transmission line from Salisbury, NB to Onslow, NS. While this project is primarily to address Nova Scotia needs, it has a positive impact on system reliability and transmission congestion. NB Power has begun system reliability discussions and preliminary analysis to determine what additional work would be needed to increase tie transfer capabilities.

Opportunities also exist to continue to increase transmission interconnection capacity with neighbouring jurisdictions, enabling increased energy imports and exports within the region. An analysis of these opportunities is further discussed in Section 6.3.

2.7. Greenhouse Gas-related Laws and Regulations

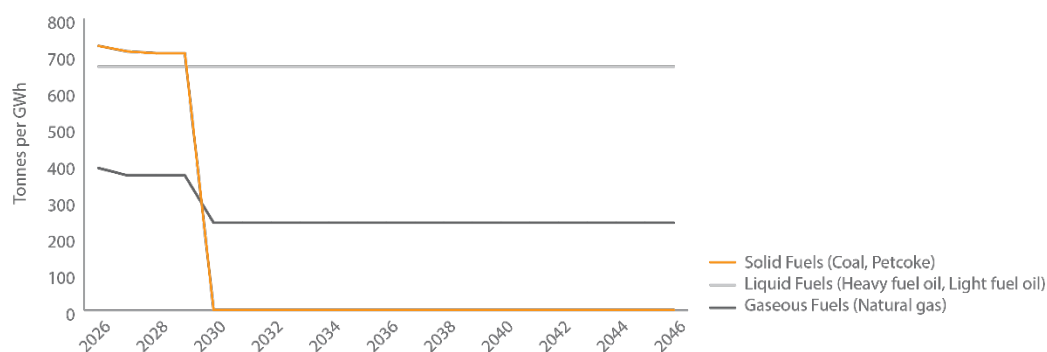
The electric utility industry is highly regulated and subject to numerous federal and provincial acts of legislation. NB Power is directed by the *Electricity Act* to follow standards set by North American Electric Reliability Corporation (NERC) for the safe and reliable operation of the bulk electric system in North America. Also, as a full member of the Northeast Power Coordinating Council (NPCC), NB Power adheres to the NPCC regional criteria and standards for the Northeastern region. Together these two organizations set out specific requirements for the planning and operation of the bulk electric system. NB Power incorporates all relevant NERC and NPCC standards and criteria into its resource adequacy planning when developing the integrated resource plan. For more details see Section 3.

Federal and provincial legislation cover multiple areas but primarily focus on the environment and carbon emissions. Provincially, the *Electricity Act* sets out specific levels of energy efficiency that must be met along with setting the minimum portion of in-province energy sales that NB Power must supply from renewable resources at 40 per cent.

The provincial Climate Change Act is a key piece of legislation that provides the framework for how emissions are managed in New Brunswick. The act enables the New Brunswick Output Based Pricing System (NB OBPS), a performance-based carbon pricing system derived from the federal backstop program that applies to large industrial facilities operating in New Brunswick. Performance standards vary by fuel type and tighten over time. NB Power will be subject to carbon taxes on emissions that exceed the performance standards set out in the NB OBPS. It is anticipated that the NB OBPS intensity standards will continue through the IRP analysis period.

Carbon pricing under the NB OBPS is \$110 per tonne for the 2026 compliance period. It is regulated to increase by \$15 per tonne each year until it reaches \$170 per tonne in 2030.

Figure 2.3: NB OBPS Emission Intensity Standards

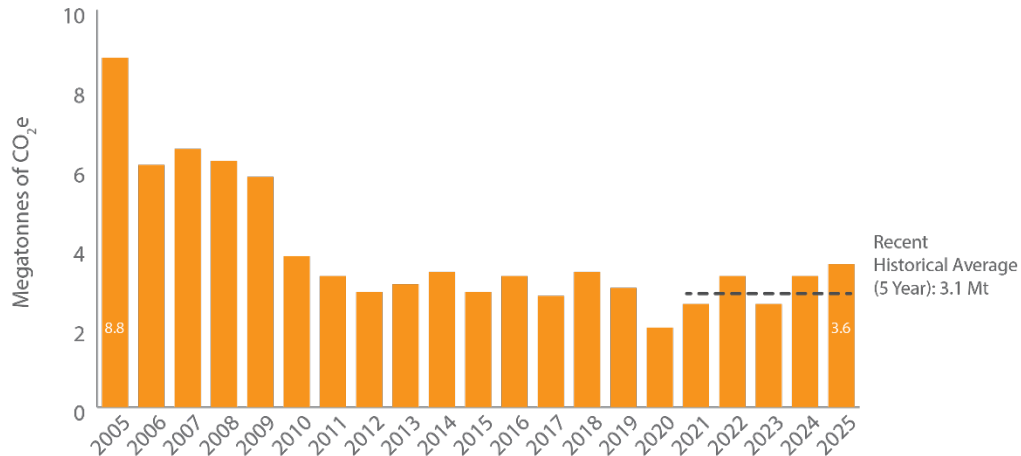


The NB OBPS is held through the forecast period for the net-zero 2050 scenarios. In the net-zero 2035 scenarios, it is assumed that the NB OBPS is replaced with a different carbon pricing paradigm, not relying on intensity standards and increasing the effective carbon price. Please refer to Section 5.2 and Appendix C – Policy Considerations for additional information on the net-zero scenario assumptions.

New Brunswick and NB Power recognize the importance of climate change and the province’s role in supporting Canada’s commitment to reducing greenhouse gas emissions. The province’s climate change targets continue to affect the pace of decarbonization at NB Power and are considered in the scenarios examined in the IRP. As shown in Figure 2.4, NB Power continues to contribute to achieving the province’s greenhouse gas reductions, having reduced our emissions by approximately 65 per cent from 2005 to today. We have incorporated existing laws and regulations into the IRP and set our sights on our contribution to the province’s next greenhouse gas reduction milestone in 2030¹⁵.

¹⁵ The province is targeting a 30 per cent reduction from 2005 levels, equivalent to 10.7 Mt in 2030

Figure 2.4: NB Power's Historical Greenhouse Gas Emissions 2005-2025^{16,17}



Federal laws and regulation also affect the way NB Power needs to look at long-term planning. In 2021, Canada set a new target to reduce CO₂ equivalent (CO₂e) emissions to 40 to 45 per cent below 2005 levels by 2030, legislated in the *Canada Net-Zero Emissions Accountability Act*¹⁸. This legislation also sets a target to achieve economy-wide net-zero by 2050. The Canada Emission Reduction Plan¹⁹ outlines targets, objectives and actions to achieving net-zero emissions across all sectors in Canada including that coal-fired generation shall be phased out by 2030.

¹⁶ Emissions for 2025 are estimated (unverified).

¹⁷ Emission data based on internal data for NB Power owned facilities.

¹⁸ Government of Canada. *Canada Net-Zero Emissions Accountability Act* (S.C. 2021, c. 22). <https://laws-lois.justice.gc.ca/eng/acts/c-19.3/fulltext.html>

¹⁹ Government of Canada, *2030 Emissions Reduction Plan*, Retrieved from <https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan.html>

Effective December 2024, the Clean Electricity Regulation (CER) is a critical piece of federal legislation that enables significant greenhouse gas reductions in the electricity sector to place Canada on a path to net-zero by 2050.²⁰ Regulated units will be limited on an annual basis to 569.4 tonnes of CO₂e per installed megawatt from 2035 to 2049²¹. From 2050 onward, the electricity sector will need to become truly net-zero, with all emissions eliminated or offset through other emission reduction or carbon removal measures.

While this legislation does limit emissions, it does not eliminate all emissions, allowing for peaking generation facilities such as combustion turbines to be operated to ensure reliability within the electricity grid.

For a detailed look at how different laws and regulations affect IRP modelling refer to Appendix C – Policy Considerations.

2.8. Future System Developments

The next 20 years and beyond will see changes to generation supply technologies and locations. Changes to supply will require new transmission infrastructure to reinforce and support current transmission infrastructure.

The IRP includes results from the analysis of supporting transmission infrastructure requirements to integrate new wind, solar, batteries and nuclear. As generation investment decisions arise, transmission costs are also included in the total cost for decision.

²⁰ Government of Canada, Clean Electricity Regulations, SOR/2024-263. Retrieved from <https://laws-lois.justice.gc.ca/eng/regulations/SOR-2024-263/FullText.html>

²¹ The Clean Electricity Regulation states that all emissions from the electricity sector are required to meet an emission intensity limit of 65 tonnes of carbon dioxide equivalent per gigawatt hour of electricity that could theoretically be generated. This is mathematically equivalent to $65 \text{ t/GWh} \times 8760 \text{ h} = 569.4 \text{ t/MW}$. For example, Coleson Cove has an installed capacity of 972 MW. It would have an emission limit of $972 \times 569.4 = 533,457$ tonnes per year.

3. System Planning

NB Power delivers safe and reliable power to New Brunswickers by ensuring the reliable operation of transmission, distribution and generation resources. Governments recognize the importance of maintaining system reliability of the electrical grid by enabling public policy that requires utilities across North America to comply with reliability standards.

In New Brunswick, NB Power follows the reliability standards from the North America Electric Reliability Council (NERC) as well as the Northeast Power Coordinating Council (NPCC). NB Power also performs planning assessments as required by NERC and NPCC for the Maritimes Area²².

The ability for NB Power to deliver safe and reliable power starts with system planning. NB Power adopts reliability standards as the framework for system planning. It is important that NB Power consider both generation capacity planning as well as transmission planning to maintain energy security and system reliability.

The utility industry is experiencing a major change in the way electricity is produced. Traditional generation sources like coal and oil are being replaced by a greater reliance on wind, solar and electricity transfers between jurisdictions. This reliance on more variable sources of generation requires greater consideration of backup sources of generation to ensure system reliability and security. Backup sources of supply are important to ensure customers receive uninterrupted electricity supplies. Whether for short-term peak coverage or for long-term supply interruptions, combustion turbines and batteries are key to ensuring reliable and consistent electricity to all of NB Power's customers.

²²The Northeast Power Coordinating Council defines the Maritimes Area as New Brunswick, Nova Scotia, Prince Edward Island and Northern Maine.

3.1. Capacity Planning

Capacity planning ensures there are enough generating resources available to meet system requirements. Traditionally, in a large thermal or hydro system, reliability planning for the grid required utilities to identify the annual or seasonal hourly peak load and build to meet that peak and then consider how the system would handle the loss of the largest generator. Each generator was effectively independent.

The transition to low-carbon electricity grids is adding complexity to the capacity planning process and changing the way reliability planning and capacity planning are done.

As variable renewable generation expands and the variability of electricity supplied to the grid rises, system planners must account for more than the system peak and unplanned generation outages. System planners must now also account for how correlated the wind and solar generation is within their system.

Multiple wind generators in a system are not independent like traditional generators. If the wind declines all the wind generation output in a region will be reduced. As a result, there is now a need to plan around periods when anticipated electricity available to the grid is restricted. In addition, the significance and impact of a reduced generation event grows as the proportion of a single source of variable renewable generation increases relative to all sources. Consequently, the peak load is no longer the only value driving the need for generating capacity.

Planners must now assess the likelihood and duration of reduced renewable generation and determine how the system will replace the lost resources. They must also evaluate how a system will meet its load requirement during extended periods when significant amounts of wind, solar or imports are unavailable and where the replacement electricity will be sourced. It is also important to consider weather pattern correlations between neighbouring jurisdictions and the potential duration of generation shortfalls.

NB Power maintains a planning reserve margin equal to 20 per cent of firm load to cover load forecast variability and generator unavailability. The 20 per cent planning reserve margin is confirmed through annual loss of load expectation studies conducted by NPCC.²³ This means the IRP model assumes across all scenarios that the firm generation capacity exceeds the maximum firm peak demand by 20 per cent across all years. This approach aligns with loss of load expectation reliability criteria set by NPCC²⁴.

3.2. Transmission Planning

The electricity system must have adequate transmission resources to transmit electricity to customers while being capable of withstanding disturbances and unplanned events.

NB Power ensures there are adequate resources to maintain reliability of the electricity system by following the NERC reliability standards and the NPCC regional criteria. The purpose of these standards is to ensure that the electrical grid is designed to operate within safe boundaries to withstand disturbances and prevent widespread cascading outages or blackouts from occurring.

NB Power performs transmission planning studies to assess system conditions based on expected customer load, generating resources and configuration of the transmission system to determine if the electrical grid has adequate resources to maintain system reliability. The results of these studies provide the safe boundaries for operating the system as well as providing upper and lower limits for importing and exporting electricity in New Brunswick.

As NB Power is a net importer of energy, having robust interconnections with neighbouring areas is a critical asset to maintaining the reliability of the electricity system in New Brunswick. NB Power relies on these interconnections every day to provide energy, capacity reserves and to maintain reliability during disturbances and unplanned events.

In the development of the IRP, the models respect the safe operating boundaries of the import and export limits when assessing the volume of energy that can be transmitted into and out of New Brunswick while meeting requirements of the reliability standards.

²³ NPCC et al., 2025 Maritimes Comprehensive Area Review of Resource Adequacy, October 2025, <https://www.npcc.org/reliability-services/>

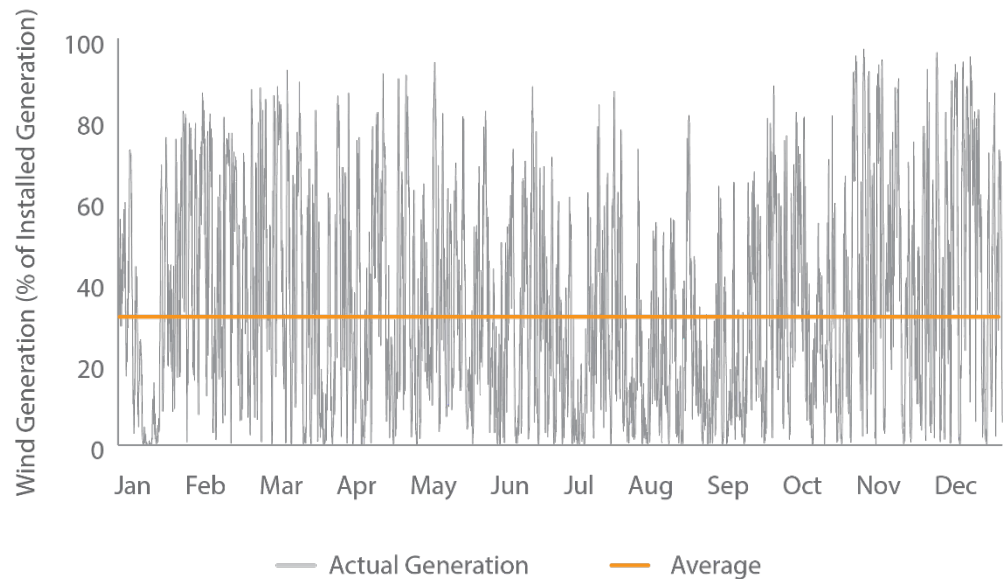
²⁴ NPCC, Directory #1: Design and Operation of the Bulk Power System, 2024, <https://www.npcc.org/standards/regional-criteria>

3.3. Intermittent Resources

One challenging aspect of capacity planning is managing the variability of resources. In New Brunswick the most common intermittent resource is wind. NB Power currently has 374 MW of wind generation in the province with another 702 MW contracted to come online by the end of 2028. The IRP must consider how this growing volume of wind will be integrated into the NB Power system and how the system will balance this variability to ensure we are able to maintain a reliable electricity supply.

Figure 3.1 shows the actual and average wind generation for the installed wind capacity in New Brunswick for 2025. The actual generation curve illustrates the variability of wind generation over a one-year period. The average curve highlights an average annual capacity factor of 33 per cent.²⁵

Figure 3.1: 2025 Hourly Wind Output



To help illustrate the variability of wind the tables below show the frequency and duration of low wind conditions in New Brunswick over the past five years.

²⁵ Improvements in wind technology have increased the efficiency and expected capacity factors of future projects to 40 per cent as shown in Appendix H.

Table 3.1 shows that for 28 per cent of the hours in a year, actual wind generation was less than 10 per cent of installed wind capacity.

Table 3.1 – Frequency of low wind periods (five-year average)

wind generation (% of installed capacity)	hours per year	hours per year (%)
less than 30%	5,572	64%
less than 20%	4,180	48%
less than 10%	2,419	28%
less than 5%	1,415	16%

Periods of low wind conditions can also last for many consecutive hours. For example, Table 3.2 shows that there were 21 times when actual wind generation was less than 10 per cent of installed wind capacity over a 24-hour period.

Table 3.2 – Frequency of sustained low wind production (i.e. less than 10 per cent of installed generation) (Five-year average)

Consecutive hours below 10%	Frequency (count)
12	67
24	21
48	5
210 (maximum)	1

Wind variability also creates ramping requirements where dispatchable generation needs to move up and down quickly to balance the variability of intermittent resources. For example, 374 MW²⁶ of existing installed wind capacity resulted in an average in-province hourly ramping requirement of 17 MW.

The ramping requirement highlights the challenges of balancing intermittent resources as more intermittent resources are added to the system. In addition, the variability of intermittent resources requires existing thermal units that cannot be cycled on and off daily be kept online to meet peak demand, balance load or balance renewables, even in hours when they are not needed. In addition to ramping, resources that provide ancillary services such as synchronous condensers are required to maintain system stability as the penetration of renewables increases on the system.

²⁶ This does not include behind the meter wind generation.

Beyond balancing generation, there are also complications with wind that arise during low load conditions. NB Power's system requirements can be as low as 900 MW on mild summer nights. Many generating stations and contracts cannot be ramped down for these low load periods and can result in a surplus of energy. As a result, NB Power can be forced to make export sales for minimal revenue or curtailments with no revenue, which add to the average energy price. This condition will also support energy storage opportunities by providing surplus energy to charge.

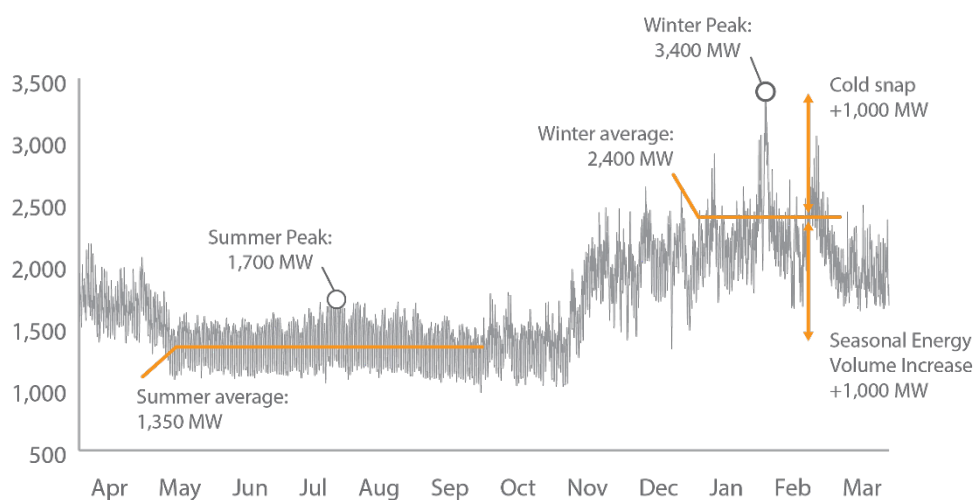
NB Power considers these operating conditions when looking at the costs and benefits of adding variable renewable resources, like wind or solar.

3.4. Variability of Load

Another challenging aspect of capacity planning is managing the variability of the load. The demand for electricity in New Brunswick varies significantly within the day and seasonally.

The diagram in Figure 3.2 shows a load shape of the energy requirements in New Brunswick across a typical one-year period. The diagram illustrates a substantial difference in seasonal energy requirements with an average increase of 77 per cent or approximately 1,000 MW difference between summer and winter. Although the discussion is normally focused on meeting winter peak demand, NB Power also faces challenges with meeting minimum peak demand that occurs in the summer and the seasonal difference in loads from winter to summer.

Figure 3.2: New Brunswick System Load Shape

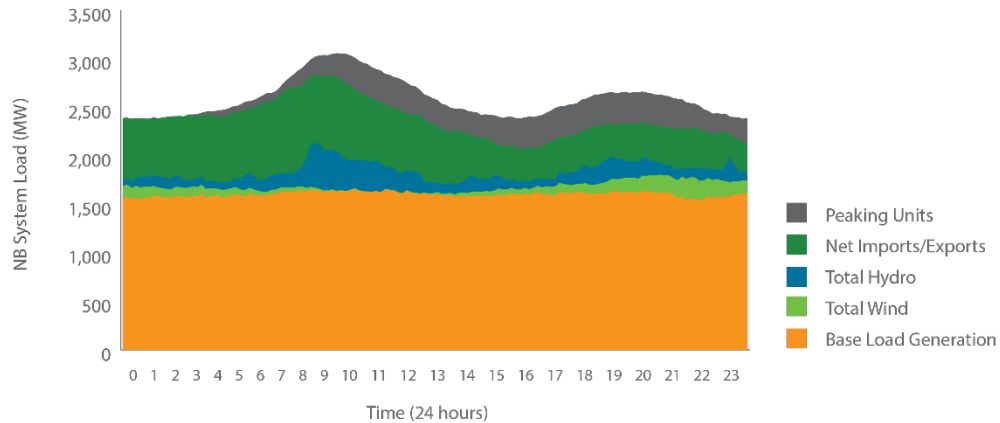


Depending on the season, the energy required to serve customers varies substantially. On a cold winter day, as shown in Figure 3.3, the peak demand in the morning rises dramatically and can exceed 3,000 MW. As the sun rises, the load drops off in the middle of the day. A second peak, typically lower, occurs in the evening as the sun sets and heating load increases as people settle in for the evening. During the overnight hours as New Brunswickers sleep, load naturally falls.

NB Power ensures energy security in the winter by serving customers with a variety of options as shown in Figure 3.3. The bottom of the supply stack is baseload generation such as Point Lepreau, Bayside and Belledune generating stations, followed by the renewable resources available that day as well as energy purchases when available from neighbouring utilities.

Although not seen in the diagram, NB Power also uses demand response programs to help reduce the load during high morning peaks. Hydro generation is used primarily to regulate and balance fluctuations in load and generation throughout the day. If required, peaking units are occasionally brought online to meet system requirements during a cold snap or when system conditions are stressed.

Figure 3.3: Winter Dispatch Example (Feb 10, 2025)

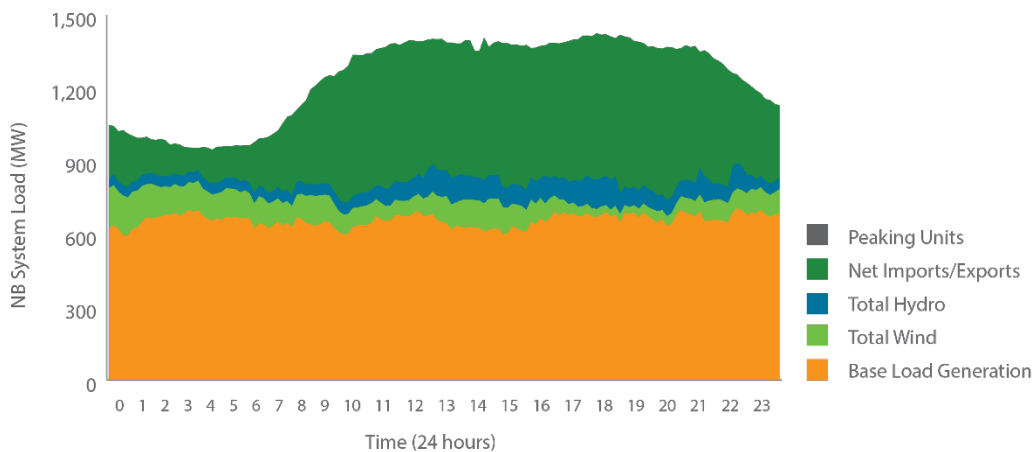


Conversely, on a hot summer day as shown in Figure 3.4, the peak demand in the morning rises gradually and remains constant throughout the day as air conditioning load is consistent. During the overnight hours as New Brunswickers sleep, load naturally falls and can be as low as 900 MW.

The supply stack for the summer is the same mix of resources but substantially lower volumes. For example, the baseload units in summer are typically 1,000 MW lower than winter, generally aligning with the change in average load across the seasons. In the case of hydro resources, river flows have a major impact on availability. When river flows are high, the hydro resources must respond to generate electricity or spill the water to lose the opportunity to produce electricity. This situation increases must-take energy and drives the need to increase exports or curtailments. When the river flows are very low, as they can be in August and September, NB Power can be forced to limit how much hydro is used to cover load and generator variability.

Today NB Power needs to use emitting generation during low hydro periods. In the future this will likely be a combination of renewables, emitting generation and batteries. This issue affects both summer and winter hydro flows. Finally, demand response programs and peaking units are typically not used during the summer to meet system requirements.

Figure 3.4: Summer Dispatch Example (Aug 26, 2025)



As we integrate more renewable resources into the system, backing down generation to meet the minimum peak in the summer will be challenging. With a minimum requirement of less than 1,000 MW, depending on the baseload units online, there may not be much flexibility to back down other resources.

NB Power (through its affiliate NB Energy Marketing) attempts to use these surpluses to recharge the hydro system's headponds or sell these surpluses into other markets but are limited by transmission interconnection limits as well as the market's ability to accept surplus energy.

Just as New Brunswick's load is lowest at night, neighbouring loads are also lowest at night, pushing down market prices and limiting economic sales. In some cases, renewable resources must be curtailed because there is nowhere for the energy to go. This provides opportunities and challenges for NB Power to consider during long term planning of the system.

3.5. Planning Capacity Contribution

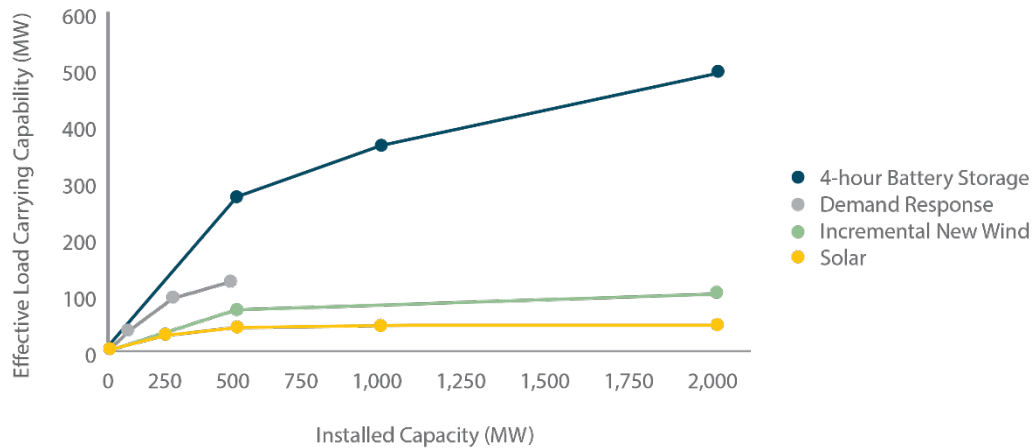
NB Power conducts effective load carrying capability (ELCC) studies using a probabilistic model to determine the ability of a resource to reliably serve demand. More specifically, ELCC is used to measure the amount of firm capacity that a resource can contribute to the grid during the critical period when demand is forecasted to be at its highest.

Historically, generation sources like hydro and thermal resources provide reliable capacity up to their unit maximum capability while intermittent and dispatch-limited resources provide less firm capacity to the grid than their installed capacity.

Figure 3.5 shows the results of the ELCC study for various intermittent and dispatch-limited technologies, indicating the diminishing effective load carrying capacity of each resource as installed capacity grows.

NB Power recognizes that wind and solar are excellent sources of low-cost energy. However, while the initial amounts of generation are reasonably beneficial to the reliability of the New Brunswick system, that benefit declines per MW of installed generation.

Figure 3.5: Effective Load Carrying Capability (ELCC)²⁷



Solar and Incremental New Wind

For solar and wind, Figure 3.5 shows the contribution of firm capacity from solar is less than 10 per cent for 500 MW of installed capacity and approximately 15 per cent for the next 500 MW of wind. These numbers are low because utilities have no control over when these units will generate, generation is varied and predictability is difficult. Furthermore, as more renewables are added to the system, reliability challenges arise more often during periods of low renewable generation.

The likelihood of intermittent resources being able to contribute toward serving load when needed is considerably less than traditional generating resources. The correlation of wind generation between sites limits the contribution of that technology and leads to declining effective load carrying capability for each new tranche of wind or solar.

Four-Hour Battery Storage

The results of the ELCC study show that the effective capacity of batteries is higher than intermittent resources with approximately 58 per cent of firm capacity being contributed from the first 500 MW of installed battery capacity.

²⁷ Incremental new wind is defined as the wind not currently installed (374 MW) or planned (702 MW). These existing and planned resources have an average ELCC of 23 per cent.

While batteries are dispatchable resources, their limited energy storage can also limit their ability to provide energy to the grid during times of need. For example, if a battery were being used to meet on-peak needs during the day and a generation outage occurred while the battery was depleted, it cannot put energy onto the system. In addition, during long periods of cold weather, the system may need energy for more hours than the battery can provide. A final example is when limited duration batteries cannot cover periods of low wind generation that can last for multiple days. These factors limit the ELCC of battery storage, and lead to declining ELCC for higher volumes.

Demand Response Programs

The ELCC for Demand Response programs is dependent on the type of load that is being reduced as well as the program design. A program that can only be called upon twice a year will not have the same ELCC as a program that could be called upon 50 times a year. Likewise, a program that targets heating load will have a limited duration as customers will not want their heat off or reduced indefinitely. Finally, some loads can have what is called a bounce back effect. This is where the load is actually higher than would normally be the case when the load comes back after a demand response event reducing ELCC.

NB Power currently has two Demand Response programs available to qualified customers totaling 80 MW and having an ELCC of approximately 40 MW. The Peak Rebate program reduces loads on weekdays from 7 to 9 a.m. for up to 12 times from December to March. The Large Industrial program targets customers who have the flexibility to reduce load any time of the year for longer durations.

In 2025, NB Power commissioned a potential study to identify opportunities to increase demand response programs. Based on the results of the study and as shown in Figure 3.5, the first 200 MW of Demand Response provides the biggest benefit with the effective capacity for programs beyond 200 MW being much smaller. This is driven by the fact that most customers are unwilling to reduce load for more than a few hours and after reducing load by 150 to 200 MW, the peak demand shifts to hours that are not part of the Demand Response event. As programs mature and optimize their design, there may be some additional incremental ELCC value for future programs. NB Power will continue to study and refine these programs to provide the most value to customers and to reliability.

3.6. Load and Resource Balance

The Load and Resource Balance provides an overall snapshot of NB Power's peak demand requirements for the study period from 2026 to 2046 and the existing and planned resources to address them.

The load and resource review in Figure 3.6 reflects the peak demand forecast for the base case and high growth scenario. Details on how the base load forecast is constructed including the high growth scenarios can be found in Appendix F – Load Forecast. The peak demand forecast includes

- energy efficiency
- demand side management
- load growth from potential new emerging industries
- planning reserve margin
- export capacity obligations

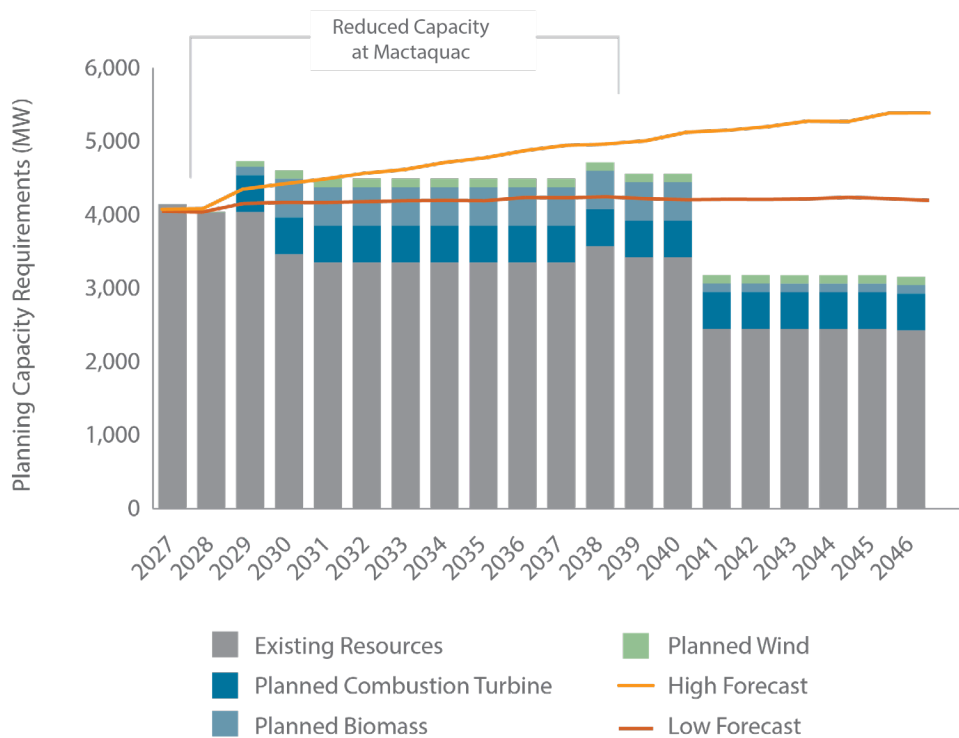
NB Power currently sells capacity and energy to Prince Edward Island and Northern Maine, with plans for a future sale of 100 MW of capacity to Nova Scotia from the RIGS project when it comes online in 2028/29. The IRP assumes that these contracts continue through the planning period.

Entering into agreements with neighbouring systems enables NB Power to benefit from economies of scale in construction of new generation sources as well as the ability to potentially market any small surplus capacity volumes caused by load growth variability to its neighbouring systems. This increases reliability for New Brunswick and brings additional value to New Brunswickers offsetting the need for higher electricity rates.

The load and resource review includes firm capacity from existing generation resources in Table 2.1. The diagram shows the following step changes

- derate of Mactaquac during refurbishment from 2027/28 to 2037/38
- construction of a 500 MW combustion turbine facility in 2028/29
- addition beginning in 2028/29 of signed PPA with new wind projects
- addition of 117 MWs of large industrial biomass generation in 2028/29
- conversion from coal to biomass at Belledune in 2029/30, reducing Belledune's net capacity by 67 MW
- loss of 270 MW by 2038/39 with the assumed end of life of Bayside
- loss of 972 MW by 2040/41 with the assumed end of life of Coleson Cove Generating Station
- loss of 410 MW by 2040/41 with the assumed end of life of Belledune

Figure 3.6: Load & Resource Review



The load and resource review diagram shows that NB Power is in a deficit of generation capacity for 2026/27 as well as 2027/28 for both the base case as well as the high load scenario. This deficit is closed in 2028/29 with the addition of the RIGS combustion turbine project. However, in the high load growth scenario an additional deficit begins in 2031/32, creating a need for new resources.

While capacity can theoretically be purchased from neighbouring jurisdictions, making such purchases is not practical or consistent with energy security requirements at a time when these areas typically peak simultaneously with New Brunswick and are also expecting significant load growth and increased capacity requirements.

The results of the load and resource balance are important to integrated resource planning as they form a logical starting point when setting up the models for the base scenarios. The load and resource balance also provides a quick snapshot of the gap in firm capacity required to meet NB Power's long-term requirements. The next steps are to determine the candidate generating resources that would be available during the study period to fill in these gaps.

4. Supply Side Resources

4.1. Supply Options

To develop the IRP, NB Power looks at supply options of varying sizes, fuel sources, technologies, operating characteristics and costs. While the economics of each option are important to be consistent with least-cost supply planning for financial sustainability, there are other factors that need to be considered such as environmental sustainability and risk management considerations, including energy security and system reliability. Different supply options provide different benefits. This section looks at the different perspectives on what the IRP considers when evaluating the various supply options to meet the needs of the electricity system of the future.

Greenhouse gas emissions, dispatch characteristics and ancillary service capabilities are important considerations, because not all generation supply options are equally capable or contribute to energy security in the same way. Electricity consumption is constantly changing and energy supply must always be in balance with energy demand. NB Power also needs to maintain a minimum level of reserve generation to meet reliability standards. Some generation options are better at these tasks than others.

Generally, a supply option is either considered fully dispatchable (controllable and predictable) or dispatch limited (limited to no control and predictability). Fully dispatchable options can be ramped up or down and can adjust output to meet the requirements of the electrical system. Other generation technologies have limited capabilities, in many cases they are limited to reducing generation to match load but cannot increase generation on demand when load increases. Some generation types have no ability to vary with demand.

Variable renewable generation sources like wind and solar are examples of dispatch limited options. These options are dependent on factors like weather conditions and time of day. Because of that, they're not able to efficiently respond at all times to the consumption needs of New Brunswickers. These resources generate when they can and don't generate when they can't, regardless of the needs of the system. Some intermittent generation like wind and solar now come with options to reduce output from the natural levels. This can offer some controllability by curtailing the energy (i.e. forgoing generation). The costs of curtailment are included in NB Power's models for these resources.

Battery storage is another example of a dispatch limited resource, as their ability to dispatch is dependent on their current state of charge. For example, if a battery was discharged during peak time or for economics at one period of the day, it may be depleted for a generation shortage later in the day. Similarly, a battery that is held for reserve in case of generation outages cannot provide reserve once the battery is discharged until it has been charged again. These limitations reduce the ability of batteries to always provide dispatchability.

To make variable renewable generation sources more viable, they are best paired with dispatchable sources, demand side management programs or energy storage to meet demand. The total amounts of this type of generation need to be studied regularly to ensure system stability and reliability.

4.2. Supply Cost Assumptions

Cost is a critical piece of the supply-side analysis. It has a significant impact on recommendations made through the IRP process. As part of the analysis, NB Power evaluated the costs of traditional supply options, distributed energy resources and demand side management programs.

Traditional Supply Options

NB Power engaged a third-party expert to provide project and operating cost parameters for potential supply options in New Brunswick. The experts provided NB Power with capital cost projections for different generation technologies that could be constructed in New Brunswick. The evaluations are based on the expert's internal sources from recent similar projects and on publicly available industry data from conferences, reports, professional papers and other publications. Historical project costs were adjusted for inflation to 2025 Canadian dollars as needed.

Using all available information, the expert created separate cost trajectories for each technology, incorporating expected increased efficiency and reduced cost as the technologies advance. These costs were then adjusted to reflect any New Brunswick-specific costs, such as labour, materials transport and others. The projections also reflected New Brunswick-specific costs obtained from recent submissions to requests for expressions of interest to build generation in New Brunswick.

The cost estimates reasonably reflect the cost of building the resource in New Brunswick. Specific sites were not selected for the alternatives except in cases involving modifications to NB Power's existing generation assets. Transmission interconnection costs were added using typical generator connection costs. Transmission reinforcement costs were added when applicable to specific technologies. Carbon costs are included in the levelized cost of energy estimates and detailed production cost modelling.

The capital costs are expressed as overnight costs²⁸. Capital cost estimates include system interconnections costs as well as technology-specific transmission system reinforcement costs. Refer to Appendix D - Economic Assumptions for parameters used to estimate capital costs.

A description of operating parameters for typical plant operations and operating modes support the operating maintenance and administration cost estimates. Costs include operators of the facility, maintenance, labour and materials as well as administrative costs to provide the facility service. Operating costs do not include fuel costs. However, information is provided on typical heat rates for each thermal power technology. NB Power estimates the appropriate fuel costs for each alternative using the thermal characteristics of the source and the long-term fuel price forecasts provided by an external fuel price forecast consultant. See Appendix E - Fuel and Market Price for more detailed information on fuel price forecast. In the specific case of natural gas combined cycle units, the costs associated with firm pipeline reservations are also included.

A summary of project cost and operating parameters for each option is provided in Appendix H - Project and Operating Cost Parameters.

²⁸ Overnight costs exclude interest during construction and escalation.

Demand Side Resources

In addition to supply options, NB Power also considers demand side resources. Demand side resources include demand response programs, energy shifting programs and modernized rate design.

Demand response programs can be called on to reduce load on-demand at times of high usage, in response to sudden losses of generation or to avoid high-priced generation. Energy shifting programs can be scheduled in advance to move energy demand from peak times or times of high prices to periods where the economics are better. Energy shifting programs are typically planned days in advance and are not readily available as emergency response. Users can also be encouraged to alter behaviours, moving energy demand from peak periods to off-peak periods through rate design. NB Power will be evaluating these types of pricing programs in the future to expand offerings to customers.

NB Power currently has a total of 80 MW of demand response programs in alignment with NB Power's Demand Side Management (DSM) Plan. NB Power has worked with industry experts to determine the volume of available demand response as well as anticipated costs.

Based on the results, the IRP model assumes there are two tranches of additional demand response volumes available. The first tranche would grow demand response offerings by 146 MW (with an ELCC of 58 MW). The second tranche would connect an additional 212 MW (with an ELCC of 37 MW). The additional tranches of demand response programs do not represent any specific demand response program but represent a collection of all types of demand response programs as NB Power expects it will take many different programs to reach the identified volumes.

In all demand side programs, there is a limit to the total potential load that can be signed up. The benefits achieved by shifting or reducing demand also diminish as the load curve flattens. Additionally, there is a societal and economic cost to demand response programs. As customers decrease their demand, residential customers forego the benefits of electricity, such as comfort, and commercial-industrial customers reduce their output or forego the pursuit of business opportunities.

The cost of demand response programs increases as the economic and societal costs increase. NB Power plans to continue studying these types of programs to refine their design to optimize customer participation, costs and effectiveness, and will explore how best to share with customers the benefit of decreased demand. As new and current technologies develop, these numbers will change and NB Power will review the amount of technically and economically achievable demand response programs in subsequent IRPs.

4.3. Supply Analysis Results

To develop the IRP, each supply option was evaluated using levelized cost analysis. The methodology evaluates the relative economics of generation projects based on parameters such as size, fuel type, capacity contribution, capacity factor and expected life. NB Power used the results of the levelized cost analysis as a screening tool to decide which technologies should be included as potential options for detailed capacity planning and production cost modelling.

The analysis includes all costs for each project over its lifetime, specifically

- initial investment costs
- operating, maintenance and administrative costs
- fuel costs (if applicable), including transportation costs for fuels like natural gas
- financing costs
- environmental costs including carbon emissions costs (if applicable)
- transmission reinforcement costs, including synchronous condensers or other ancillary supports (if applicable)

NB Power used three types of levelized cost analyses to evaluate potential energy sources and capacity against system requirements.

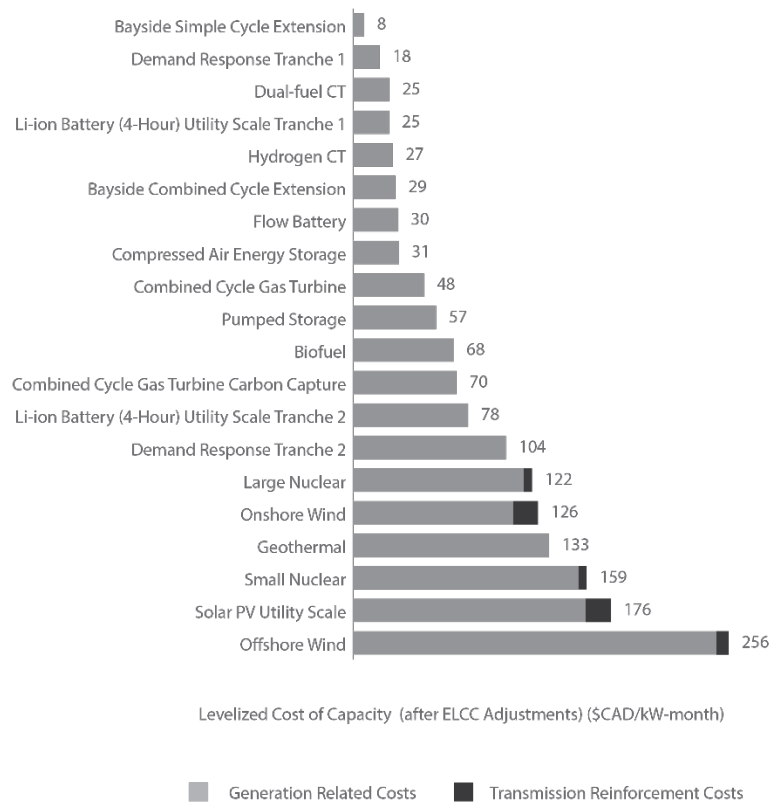
Levelized Cost of Capacity

The levelized cost of capacity is the revenue per unit of capacity that is required to recover all investment and fixed operating costs, expressed as dollars per kilowatt-month (kW-month), adjusted for the marginal ELCC for each option.

For traditional dispatchable generating technologies, the installed capacity and capacity credit are equal. For intermittent or non-dispatchable technologies, the capacity credit is less than the installed capacity (refer to Section 3.5). As a result, dispatchable non-intermittent generation resources have a lower levelized cost of capacity when compared to non-dispatchable, intermittent technologies.

In the IRP analysis, levelized costs of capacity range from a low of \$8 per kW-month for the Bayside Generating Station's gas simple cycle turbine extension to \$256 per kW-month for off-shore wind.

Figure 4.1: Levelized Cost of Capacity (\$2030)^{29,30}



To calculate the Levelized Cost of Capacity for energy storage technologies such as batteries, the expected fixed costs of the storage system are divided by the load-carrying capability. When compared to combustion turbines, one of the lowest-cost capacity options, storage options can be cost competitive for the first 500 MW of installed capacity (290 MW of effective capacity). Above these levels, Battery Storage becomes less effective than other technologies as the duration of the capacity need extends. By balancing the needs for short-duration and long-duration capacity, NB Power recognizes the part batteries will play in solving for total system capacity requirements.

For more details on the quantitative differences of the supply options included in the analysis, refer to Appendix H.

²⁹ The LCOC for the first tranche (500 MW) and second tranche of Li-ion battery storage are adjusted using an ELCC of 58 per cent and 18 per cent respectively.

³⁰ The LCOC for the first tranche (146 MW) and second tranche of demand response are adjusted using an ELCC of 40 per cent and 17 per cent respectively.

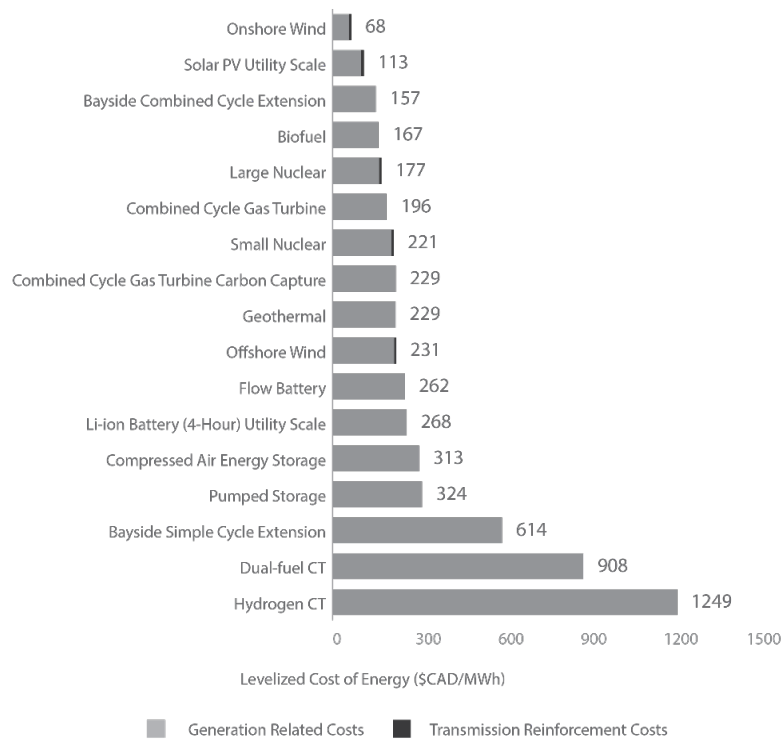
Levelized Cost of Energy

Levelized cost of energy is the average revenue per unit of energy production, expressed as dollars per megawatt-hour, required by a project owner to recover all investment and operating costs inclusive of fuel and carbon costs³¹. It identifies the cost at which technologies provide energy to the grid.

Levelized cost of energy is used only for screening which resources should be considered in the detailed expansion planning model, not to determine which resource should be selected for construction. It does not consider dispatch characteristics, reliability, energy security, load following potential or contribution to capacity requirements and therefore was only used as a screening tool³².

In the IRP analysis, the levelized cost of energy ranges from a low of \$68 per MWh for onshore wind options to a high of \$1,249 per MWh for hydrogen-fueled combustion turbines.

Figure 4.2: Levelized Cost of Energy (\$2030)



³¹ "Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement," U.S. Energy Information Administration, July 2013, https://www.eia.gov/renewable/workshop/gencosts/pdf/methodology_supplement.pdf

³² "Beyond LCOE: A Systems-Oriented Perspective for Evaluating Electricity Decarbonization Pathways", Clean Air Task Force, June 10, 2025, <https://www.ourenergypolicy.org/resources/beyond-lcoe-a-systems-oriented-perspective-for-evaluating-electricity-decarbonization-pathways/>

Battery systems do not generate electricity, but store previously generated energy then return it to the grid when needed. This process has losses, with different batteries having different round-trip efficiencies. The cost of storage must evaluate the round-trip efficiency of the system and discount the installed capacity to account for the system's contribution to load-carrying capability.

To calculate the Levelized Cost of Energy (LCOE) for batteries, NB Power calculates the average cost of energy during charging and adds the cost of losses during charging, storage and discharge to determine an LCOE value for energy discharged to the grid. For more details, refer to Appendix H.

4.4. Selected Supply Options

Based on the levelized cost analysis and the load and resource assessment, it is possible to develop alternative system plans that can be evaluated in detail through production cost and financial modelling. System plans need to address renewable portfolio standards, greenhouse gas emission constraints and long-term capital stock turnover.

Supply options show a significant variation in both energy and capacity costs. NB Power conducted screening based on emission profiles, dispatch characteristics and economics. Emission profiles of each option were reviewed to ensure a sufficient level of carbon-free generation options were made available in the analysis to meet current and future renewable portfolio standard and net-zero targets. Dispatch characteristics of each option were reviewed to ensure the various system and reserve requirements were met. Finally, levelized costs were reviewed and unique generating technologies with the lowest costs were included in the initial screening.

Generation technologies with high costs or low costs that are not technically feasible in New Brunswick were screened out. When similar options were available, only one technology was screened in. For example, the off-shore wind was not selected for further analysis as it is very similar to the on-shore wind option, but with a much higher LCOE.

Combustion turbines are a low-cost capacity source to back up the grid while maintaining usage levels below the allowable operating limits. They provide needed reliability with limited capital investment and the technology is mature and predictable. Batteries can also provide capacity and reliability but typically are limited to short periods of generation before requiring charging. Batteries can contribute to providing ancillary services such as load following and reserve.

Based on the results of the levelized cost analysis, system requirements, environmental and dispatch characteristics of each supply option, the following mix of conventional and alternative options were selected for further evaluation using the PLEXOS detailed capacity expansion model. For detailed information on the attributes of each supply option, refer to Appendix H.

Table 4.1 Summary of Supply Options

Supply Options	LCOE (\$/MWh)	LCOC (\$/kw month)
Bayside simple cycle extension	600	8
Demand response tranche 1	n/a	18
Dual-fuel combustion turbine	908	25
Li-ion Battery (4-Hour) Utility Scale	268	25
Hydrogen combustion turbine	1,249	27
Bayside combined cycle extension	181	29
Combined cycle gas turbine (CCGT)	196	48
Combined cycle gas turbine carbon capture (CCGT-CC)	229	70
Li-ion battery (4-Hour) utility scale tranche 2	268	78
Demand response tranche 2	n/a	104
Onshore wind	68	126

5. Analysis & Results

5.1. Methodology

This IRP uses the least-cost-of-service and greenhouse gas emission impacts as key metrics. Least-cost-of-service is measured by taking the present value of the estimated annual partial revenue requirements³³ over 20 years for each expansion plan. This helps inform the long-term costs of the different scenarios and sensitivities. Emission impact is determined by calculating the total emission output for each plan over the 20-year planning horizon. All plans are developed in a way that meets renewable generation requirements and adheres to all laws and regulations on managing greenhouse gas emissions.

NB Power uses a software application called PLEXOS to determine the least-cost expansion plan. PLEXOS is a production simulation model used by utility companies to optimize near-term planned operations and long-term expansion planning.

To develop the least-cost plan, all reasonable and feasible supply-side and demand-side alternatives are provided as inputs and run through the PLEXOS LT module. This allows the utility to find the least-cost plan that meets forecasted electricity requirements within New Brunswick while meeting all policy objectives including legal and regulatory requirements. The results are then run through PLEXOS MT/ST to determine the operational feasibility of the plan. The MT/ST module is a chronological, hourly simulation that accounts for energy security through the provision of ancillary services, unit commitments and ramping constraints among other items (e.g. state of charge for battery objects). This ensures that the least-cost plan reliably meets future load requirements, environmental constraints and system reliability requirements.

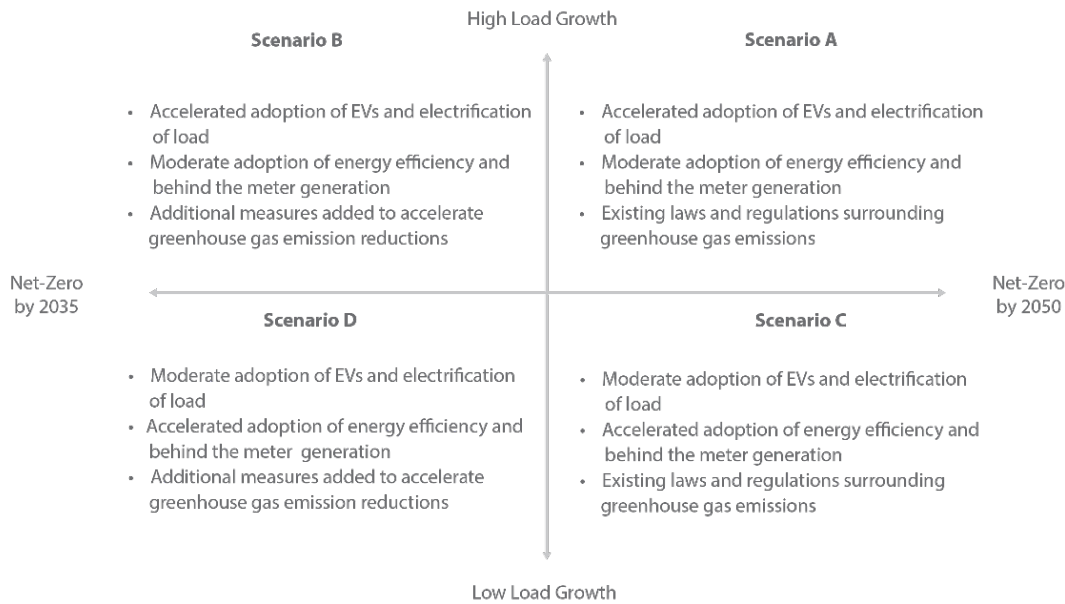
³³ *Partial revenue requirement is defined as the total revenue to be recovered from in-province electricity customers. This differs from traditional revenue requirement in that it is reduced by miscellaneous and export revenues.*

Operational feasibility checks are completed for capacity based ancillary services including automatic generator control, load following, spinning and supplemental operating reserves³⁴. To the extent possible, transmission-related constraints and costs are included in the analysis. Estimates around transmission system upgrades that will be needed for different technologies were calculated and applied to the technology costs. However, detailed transmission system operations and integration studies were not within scope and additional studies will need to be performed regularly to update these assumptions going forward.

5.2. Scenario-Based Approach

NB Power acknowledges the complexity of the electricity grid, its impact on New Brunswick, and the uncertainty of the future. For these reasons, NB Power applies a scenario-based approach to analyze the energy landscape over the next 20 years. By identifying the two external driving forces of load growth and the pace of decarbonization, NB Power has constructed four scenarios to create a spectrum of potential realities to stress test. The table below provides a summary of the scenarios with more detail for each in the following sections.

Figure 5.1: Scenario Summary



³⁴ For additional details on reserves, refer to the NB Open Access Transmission Tariff, Schedules 3, 5 and 6. https://tso.nbpower.com/Public/en/docs-EN/tariff/TransmissionTariff_20230101_EN.pdf

Load Growth

NB Power views projected load growth with a high degree of uncertainty. Additionally, there is value in understanding what types of resources NB Power would invest in if load growth were to materialize unexpectedly. Contributing factors such as technology, climate change, customer expectations, and emerging industries are impacting how customers use electricity.

NB Power established two diverging load scenarios that could provide reasonable bookends on the likely load growth reality. Starting with the NB Power 2025 base load forecast, NB Power adjusted four different inputs to come up with these different forecasts. The four inputs are the pace of EV adoption, the pace of load electrification, the impact of energy efficiency and the growth of behind-the-meter generation. The specifics of these changes are discussed below. Details showing a breakdown on how each factor impacts the high and low load growth forecast for scenarios A through D can be found in Appendix F – Load Forecasts.

The pace of EV adoption into the future has significant uncertainty. To account for this uncertainty NB Power has selected two different EV adoption curves based on a study performed by Dunskey Energy Consulting. The low load growth scenarios follow EV adoption forecasts based on minimal efforts of support for EV adoption including current incentive levels along with reductions and eliminations of government incentives over time. Under these growth assumptions, sales increased by 2,974 GWh by 2045/46. The high load growth scenarios include an enhanced EV growth forecast based on moderate support for EV adoption and increases this energy requirement. In the high load growth scenarios, EV sales increased to 3,991 GWh by 2045/46 (an increase of 1,024 GWh or 7 per cent of current in-province energy requirements).

As the Canadian Economy decarbonizes there will be changes to many industrial processes as well as the development of potential new industries. NB Power recognizes that this adds a level of uncertainty to the industrial load forecast. To cover this uncertainty NB Power has developed two different trajectories for industrial load growth.

The low load growth scenarios show a flat trajectory for industrial load in the province, prior to the impacts of energy efficiency programs. In the high load growth scenarios, 800 MW (6,000 GWh annually) of new industrial load is added between 2029/30 and 2045/46. This is to represent new loads from electrification of industrial processes, electrification of commercial heating and cooling and well as the potential for new loads such as hydrogen production, data centers, new manufacturing or mining. The addition of 800 MW of new load over the planning horizon represents a higher rate of growth for industrial load than anything seen in the last 50 years.

NB Power has made considerable progress delivering on energy efficiency targets and will continue to offer programs in alignment with government regulations. NB Power receives significant funding from the Federal and Provincial governments to support efficiency programs and to help customers reduce their power bills. There is potential for increases in funding to drive increases in efficiency targets in the future. The following assumptions for energy efficiency were obtained from a recent Dunskey potential study

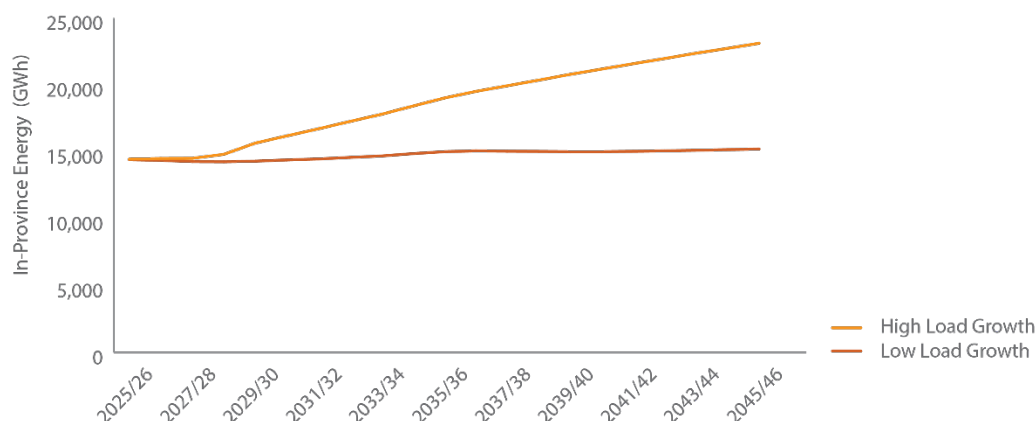
- the high load growth scenarios assume a moderate adoption of energy efficiency which meets the current legislated targets
 - these targets escalate to an annual efficiency savings target of 0.75 per cent per year in all years after 2027/28
- the low load growth scenarios assume an accelerated adoption of energy efficiency is achieved which exceeds the legislated targets, equaling reductions of approximately 1.0 per cent of sales per year

As identified in Section 2, behind-the-meter (BTM) volumes have been increasing over the past five years and has reached 27 MW³⁵ of connected installed capacity. BTM generation is expected to continue to grow through the next 20 years as the electricity grid changes. NB Power has taken the inputs from the Dunskey potential study to develop two BTM growth scenarios. In the high-load growth scenarios the base BTM growth was used and in the low load growth scenarios we have used the enhanced BTM adoption scenario, leading to lower overall sales to customers.

Taking the impacts of EV growth, industrial growth, energy efficiency and BTM growth together, the high load growth scenarios increase from 14.4 TWh in 2025/26 up to 23.1 TWh in 2045/46, and average annual growth rate of 2.4 per cent. The low load growth scenarios change from 14.4 TWh in 2025/26 to 15.2 TWh in 2045/46, an average annual growth rate of just 0.3 per cent. Additional detail on the development of the load forecast is included in Appendix F.

³⁵ As of January 2026, NB Power has 27 MW of installed capacity under its net metering program.

Figure 5.2: Total In-Province Energy Requirements



Net-Zero Timing

New Brunswick is already experiencing the impacts of climate change.³⁶ NB Power recognizes the impact of carbon emissions on the environment and our economy, and is committed to reducing carbon emissions from electricity generation while maintaining costs as low as possible.

In the 2023 IRP, NB Power explored pathways to achieving a net-zero electricity system with a fixed date of 2035. NB Power acknowledges that federal and provincial laws and regulations for greenhouse gas emissions are evolving. As shown in Figure 5.1, the 2026 IRP NB Power explores pathways to achieving a net-zero electricity system across a range of dates, net-zero by 2035 (aligning with the 2023 IRP) to net-zero by 2050 (aligning with existing laws and regulations surrounding greenhouse gas emissions). The current target of the federal government is to achieve a net-zero economy by 2050.

³⁶ Province of New Brunswick, *Provincial Climate Change Risk Assessment*, <https://www.gnb.ca/en/topic/environment-resources/climate-change/climate-change-impacts/climate-risk-assessment.html>

This target includes a number of interim steps to move in this direction over time including (as detailed in Appendix C – Policy Considerations)

- prohibiting the use of coal in 2030 and beyond
- implementing a carbon tax increasing to \$170/tonne by 2030
- implementation of the Clean Electricity Regulation, which limits the emissions of generating facilities 2035 and beyond

The Government of New Brunswick produced a Climate Change Action Plan (2022-2027)³⁷ and a provincial energy strategy in 2023³⁸. These documents did not explicitly set a target date for achieving a net-zero electricity system, and there is no legislative directive on this date. Rather, they contemplated achieving the goals of the federal clean electricity regulation to make progress toward a clean energy grid with a commitment for New Brunswick to achieve net-zero by 2050.

The assumptions used within the net-zero 2050 scenarios (Scenario A and C) align with the existing laws and regulations surrounding greenhouse gas emissions.

Scenarios B and D contemplate changes that would further restrict emissions in 2035 and beyond. These scenarios assume a replacement of the Output-Based Pricing System (OBPS) with a simplified direct tax or offset system which assumes all emissions are subject to a \$340/tonne carbon price. This price could reflect a tax, payable to the government to be reinvested into emission reductions to offset the emissions, or an investment in carbon offset credits to reduce net emissions to zero for NB Power.

The assumptions used within the net-zero 2035 scenarios (Scenario B and D) are more restrictive than existing laws and regulations surrounding greenhouse gas emissions to demonstrate how NB Power could accelerate the reduction of emissions.

³⁷ Province of New Brunswick, *Our Pathway Towards Decarbonization and Climate Resilience: New Brunswick's Climate Change Action Plan 2022–2027, Action Plan 2022–2027*, <https://www2.gnb.ca/content/dam/gnb/Corporate/Promo/climate/climate-change-action-plan.pdf>

³⁸ Province of New Brunswick, *Powering Our Economy and the World with Clean Energy: Our Path Forward to 2035, Clean Energy Strategy*, <https://www2.gnb.ca/content/dam/gnb/Corporate/Promo/energy-energie/GNB-CleanEnergy.pdf>

It is important to note that in some contexts, it may be appropriate to put more weight on the net-zero 2050 scenarios that align with current laws and regulations. The net-zero 2035 scenarios by contrast may in some contexts be viewed as an upper bookend for emission reductions and associated costs. For more detail on the impacts including federal and provincial carbon policies, please refer to Appendix C – Policy Considerations.

5.3. Results

The future of electricity in New Brunswick continues to show a decoupling of the generation sources providing energy and those providing capacity in the future. Traditional baseload generators that run at full power for most of the year to serve fixed loads are becoming a smaller percentage of the energy needs in New Brunswick.

The results of the base scenarios show that a combination of renewables, power purchases and energy efficiency programs can provide the majority of the energy required by the system. The model also shows that to meet the reliability needs of the system to ensure uninterrupted supply, dual-fueled combustion turbines, batteries and demand response programs are needed for capacity. Only in scenario A (high load growth/net-zero 2050) does a natural gas combined cycle unit, in this case the Bayside extension, become part of the most cost-effective generation mix. The future grid in New Brunswick will be one with large volumes of must-take³⁹ variable renewable generation backed up by quick starting combustion turbines and batteries to help keep the system in balance.

Across all scenarios the existing commitments for 500 MW of combustion turbines and 702 MW of wind generation are foundational. In Scenarios A and B, new batteries and an increase in the demand response programs are needed for capacity by 2031/32 and additional wind for energy. This continues to increase each year until 2035/36 when batteries reach an installed capacity of 500 MW and their effective load carrying capability falls to a level where they are no longer cost competitive with combustion turbines for providing capacity. Renewable growth is split between wind and solar, each with its characteristic generation profile.

³⁹ Must-take energy can be curtailed for system security and reliability, for example if there is no need in New Brunswick and no market in neighbouring utilities.

Scenario A chooses to extend Bayside Generating Station as a combined cycle unit in 2039 for energy and capacity. This is due to the high load and less restrictive carbon assumptions in the net-zero 2050 scenario. In Scenario B where carbon costs rules are more restrictive, the plan converts the Bayside Generating Station into a simple cycle gas turbine in 2038/39.

In scenarios C and D, industrial and electric vehicle loads do not grow as rapidly and efficiency and behind-the-meter generation suppress the energy needs, which together result in very little growth. These scenarios build new resources primarily due to the retirement of existing generating assets. New generation is not needed until 2040/41 when both Coleson Cove and Belledune generating stations are assumed to reach the end of their useful life.

The loss of almost 1,500 MW of generating capacity in scenarios C and D requires a suite of new generating capacity. The model selects batteries, dual-fueled combustion turbines, solar, wind and demand response to meet this large loss of capacity and energy. In all cases extending Bayside is the cheapest source of firm capacity. In each scenario we see significant capacity contributions come from new combustion turbines.

It is important to note that in the 2030s as the end of useful life approaches, engineering assessments will be performed to optimize the exact date the units will retire. In practice, NB Power would work to stagger the retirement of generating capacity to allow for more gradual replacement of resources.

In all scenarios we see increases to variable renewable generation. This will create operational challenges that will need to be met by a combination of batteries, demand response and dual-fueled combustion turbines. Batteries will be helpful for short duration periods of energy shifting and support ramping. Combustion turbines will be needed to ensure reliability during extended periods of low renewable generation and will provide valuable ancillary services support.

The contribution of wind, solar, battery storage and demand response toward effective capacity is reduced from the installed capacity in accordance with the effective load carry capability (ELCC) analysis discussed in Section 3.5. An inflection point occurs at installed capacities of 500 MW for batteries and 146 MW for demand response. Above these inflection points additions to batteries and DR become too expensive compared to low energy capacity options like combustion turbines.

Figure 5.3 shows the effective capacity for meeting reliability needs, which includes the adjustments for ELCC. The installed (nameplate) capacity of each unit is shown in Figure 5.4. This provides a view of the significance of these technologies, particularly onshore wind and solar. Appendix I – Expansion Tables includes tables with detailed expansion plans for each scenario.

Figure 5.3: Effective (Firm) Capacity by Scenario

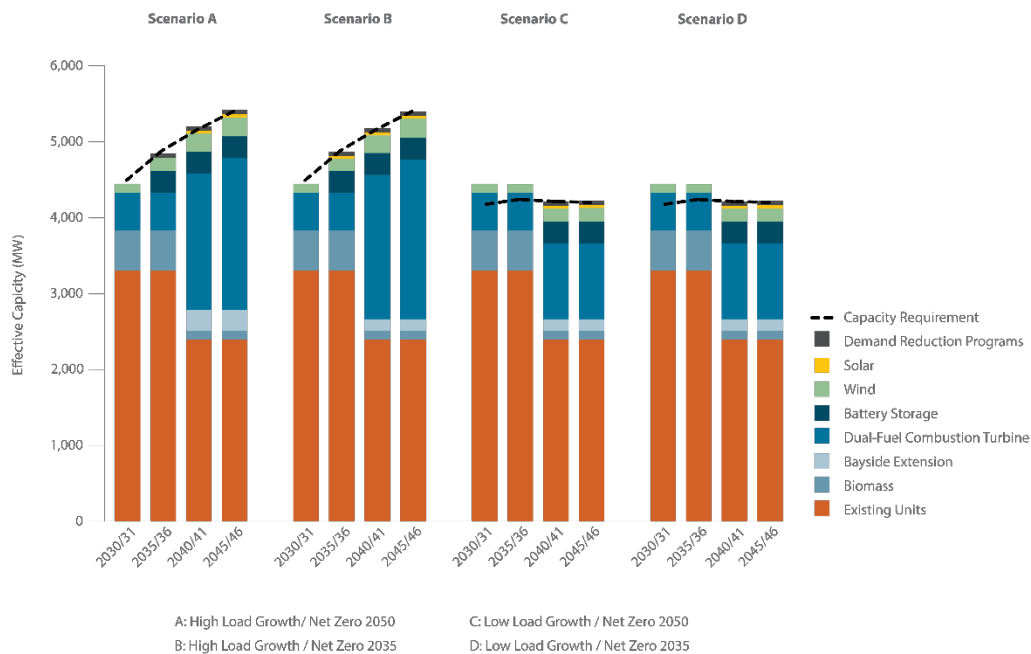
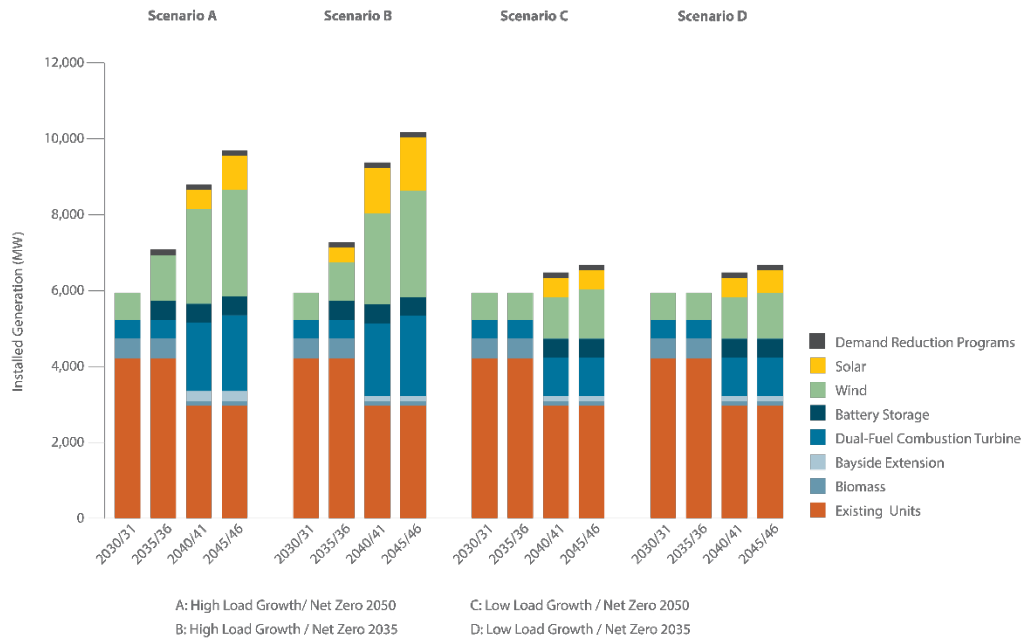


Figure 5.4: Installed (Nameplate) Generation by Scenario



All scenarios show new wind, solar, batteries, demand response programs and combustion turbines. The difference is the timing and magnitude of the needs. The timing of the first tranche of batteries suggests that the question of which capacity resource, batteries or combustion turbines is ideal, will be based on the specific system reliability needs at the time as the costs appear to be similar for capacity. Beyond 500 MW, the ELCC of batteries pushes the firm capacity benefit to a level that makes it uneconomic compared to combustion turbines.

The results show that NB Power should continue expanding demand response options. Balancing the cost of these programs against alternatives will be important as the programs grow. Beyond an additional 146 MW, the ELCC of demand response combined with escalating program costs reduce the overall cost effectiveness of these programs.

The Bayside Generating Station is extended in all base scenarios, with a simple-cycle (peaking) option selected in Scenarios B, C and D while the combined-cycle (baseload) option is selected in Scenario A. The larger, combined-cycle operation is not preferred in the lower load scenarios nor in the net-zero 2035 scenarios that would more heavily restrict high capacity factor (baseload) options.

The timing of wind and solar investments is dependent on a number of factors. Load growth plays a significant role in accelerating the development of renewables. Furthermore, the deployment of new renewables in the expansion plan is sensitive to the pricing assumptions for new renewables and is also impacted by changes to the pace of decarbonization. Support for these types of projects from government or changes in the projected cost of new resources could also lead to accelerated investment relative to the build out in Scenarios C and D.

New wind and solar are always supported by an addition of some sort of dispatchable resource, typically batteries or combustion turbines, in order to help integrate the renewables and maintain reliability.

Table 5.1 contains a summary of projects that are needed in all base scenarios. These projects provide value to the system and are not sensitive to the key uncertainties identified like load growth and the pace of decarbonization. In the case of the Bayside extension at a minimum the gas turbine will continue to operate beyond the 2038 retirement date. For demand response and batteries, the date is the latest date when these volumes will be needed.

Table 5.1: Summary of Common Actions Across Base Scenarios

Installed Generation	Technology
410 MW	Belledune biomass
150-270 MW	Bayside extension
500 MW	Batteries
146 MW	Demand response
400-2,100 MW	Wind
500-1,500 MW	Solar
500-1,600 MW	Combustion turbines

In addition to the common actions across all base scenarios, it is worthwhile to highlight the additional requirements that are included in both scenarios A and B but not included in Scenarios C and D. This comparison of the high load growth scenarios to the low load growth scenarios helps provide insight into what are the most economic options for responding to growth. They include

- acceleration of demand response programs
- acceleration of wind and solar generation
- acceleration of battery storage
- acceleration of dual-fueled combustion turbines
- higher total volume of wind and solar
- higher total volume of combustion turbines

Notably, the total volume of demand response and battery storage is not impacted by load growth, just the timing.

5.4. Timelines to In-Service

Another key consideration is the timeline to in-service for selected projects. These vary by technology.

From the time NB Power signs a Power Purchase Agreement (PPA) the In-Service Date of a wind and solar project can typically range from two- to four-years. Prior to this there is an additional year or more of pre-work split between NB Power's work to identify the need and issue procurements and the developer's work on putting together a detailed project proposal.

For example, NB Power issued a Request for Expressions of Interest for new renewables in 2023 that resulted in a number of PPAs signed in 2024 and 2025 with in-service dates in 2027 and 2028. Project readiness and maturity can impact this timeline. NB Power had an additional accelerated REOI stream issued in 2025, resulting in a PPA targeting in-service in 2028. All-in project timeline from inception to in-service is in the range of three to five years for renewables.

NB Power does not yet have any direct experience with battery storage projects, but based on the experience of others, it is expected that from Storage Services Agreement to in-service would be approximately 2-3 years with a year or more of time required for procurement, approvals and developing an agreement.

New combustion turbines or other thermal generators are approximately a 5-year timeline, as validated by NB Power's recent experience with the RIGS project. Recent supply chain pressures have put upward pressure on this date, with current timelines exceeding 5 years.

The key takeaway is that based on the project dates identified, a number of steps must be taken in advance of signing an agreement with a developer, and there is additional time required to get a project in-service. There is an opportunity to mature projects prior to signing an agreement so they are in a more advanced state if an accelerated need were to arise.

Demand response programs are different from other types of projects. These programs generally grow gradually over five or more years. It is important that NB Power begin laying that groundwork today for the needs that are foreseen in the early 2030s.

5.5. Energy Balance and Emissions

The energy balance in Figure 5.5 shows the declining contribution of emitting generation over time. In three of the four scenarios emitting generation is minimal by the year 2040/41. This causes a marked decline in greenhouse gas emissions, with three of the four scenarios hitting a 95 per cent reduction from 2005 levels during the planning horizon. This is in keeping with the provincial government plan to reach industry wide net-zero commitments by 2050.

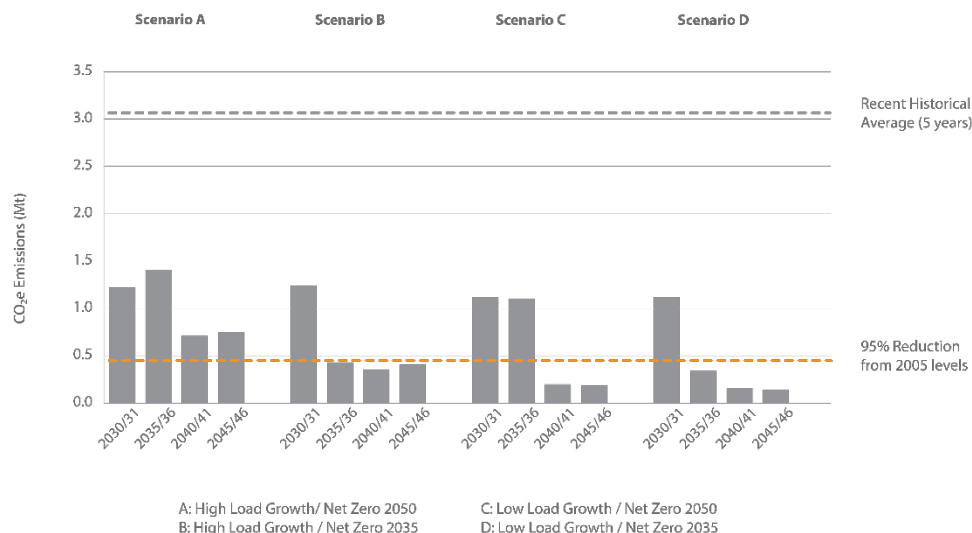
Figure 5.5: Energy Balance by Scenario⁴⁰



⁴⁰ Fluctuations in energy from nuclear due to planned biennial outages.

The energy balance shows a growing share of renewables over time. Emitting generation is significantly reduced as well, totaling just 6 per cent of the total energy sourced by 2040/41 in scenario A (from approximately 20-25 per cent today). This number is even more deeply reduced in Scenarios B, C, and D to below 2 per cent. There is also a general trend of increasing reliance on neighbouring jurisdictions with both imports and exports growing throughout the period.

Figure 5.6: Greenhouse Gas Emissions by Scenario (CO₂e)



In 2005 NB Power's emissions for the year were 8.8 megatonnes (Mt) of CO₂e, the above chart shows the magnitude of the emission reductions already achieved with recent historical emissions averaging 3.1 Mt, a reduction of approximately 65 per cent.

As shown in Figure 5.6 only scenario A where load growth is high and there isn't a specific regulatory requirement to meet net-zero until 2050 does NB Powers emissions stay above 95 per cent reduction from 2005 levels in the later years. Even in this scenario NB Power's total emissions on an annual average level are well below one megatonne, a major reduction from recent historical levels and showing significant progress toward the net-zero 2050 goal.

Scenario B (high load growth/net-zero 2035) achieves a more than 95 per cent reduction from 2005 levels after 2035. These remaining emissions would be offset either through purchasing carbon offset credits or paying a carbon tax to the government, who would then invest in carbon reduction initiatives in other areas of the economy.

In the low load scenarios (C and D), the 95 per cent reduction from 2005 levels target is achieved in the later years but is accelerated to 2035 in Scenario D.

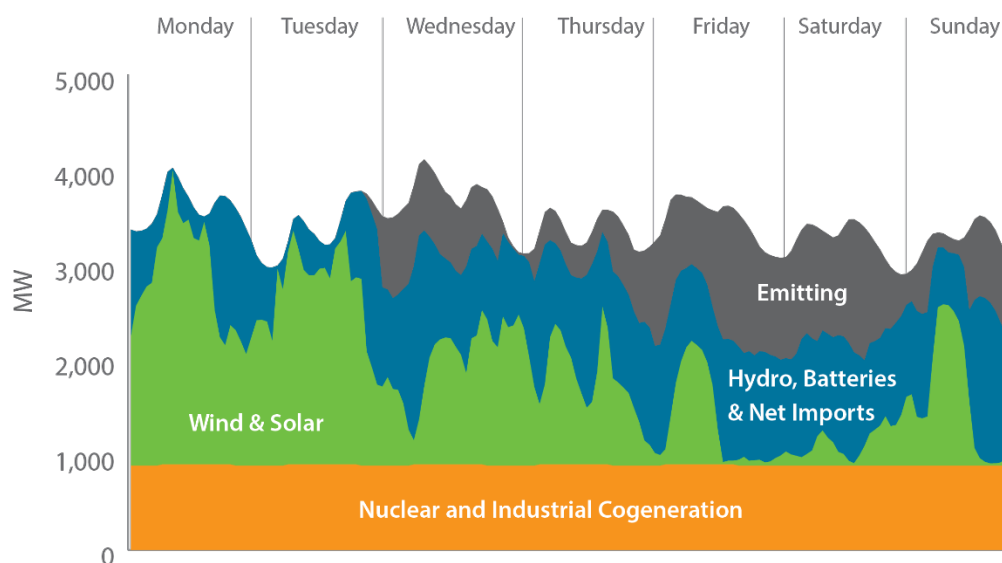
5.6. Operational Characteristics

A view of the hourly dispatch can also provide additional understanding of how the energy needs are being met at a finer resolution. Figure 5.7 shows the hourly dispatch for Scenario B in a week in January 2046. During the Monday and Tuesday of this week, the majority of generation needs are able to be met without emitting resources. However, in the periods of low renewable generation, there is a high need for emitting generation. Note that without the thermal generation provided, reliability could not be maintained through this period.

The system would need an unreasonable volume of battery storage to maintain generation adequacy through this challenging period without the availability of thermal resources⁴¹. Imports are already close to their maximum during the periods of low wind and solar. In this scenario 500 MW of batteries are built in and play an important role but charging becomes a significant challenge as the week progresses. The role of thermal generation that can inject energy into the grid for prolonged periods to maintain reliability is paramount as society becomes increasingly dependent on electricity.

⁴¹ For illustrative purposes, emitting energy supplied an average of 1,160 MW over the final two days in the sample week shown in Figure 6.7. To provide this same level of energy output from batteries would require over 14,000 MW of 4-hour battery storage, or approximately 5,000 MW of longer duration (12-hr) battery storage.

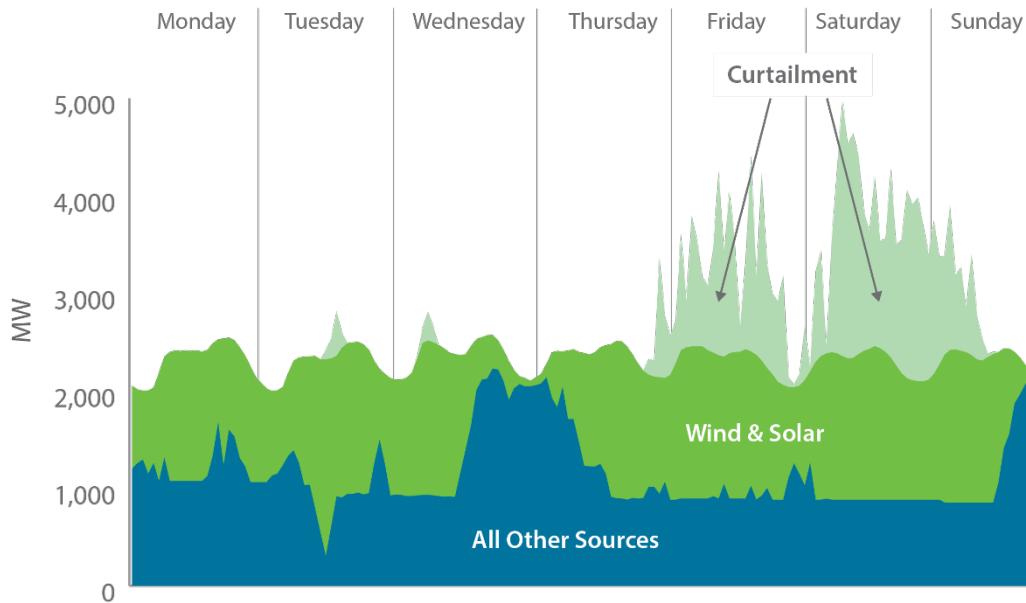
Figure 5.7: Scenario B - Hourly Energy Balance for a Week in January 2046



The low-load periods provide a different type of challenge, with over-generation becoming an issue. Figure 5.8 shows a week in October 2045 from Scenario B, where excess generation is first exported into neighbouring jurisdictions up to its limit⁴² and then required to curtail to maintain reliability. As the penetration of renewables grows, the ability to reduce output to respond to curtailment needs becomes increasingly important. In some hours curtailments reach levels over 2,000 MW.

⁴² Exports depend on neighbours' needs, current system constraints and market value. Additional variable renewable generation could limit export opportunities further than the constraints seen in today's market.

Figure 5.8: Scenario B - Hourly Energy Balance for a Week in October 2045



5.7. Financial Impacts

The financial analysis and the metrics discussed in the IRP are based on the cost of service for the utility in the context of planning the electricity system. The IRP analysis does not reflect the broader economic and societal impacts as a result of the electricity system.

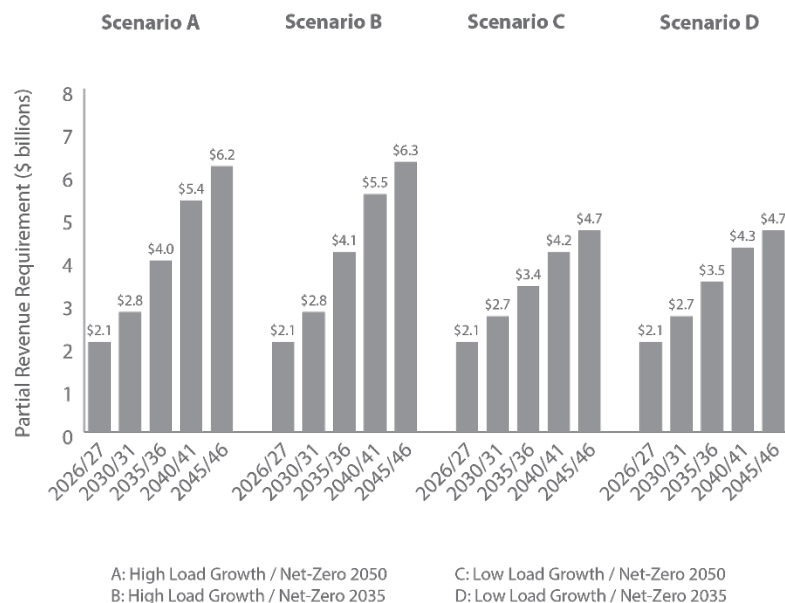
The costs presented should be considered as the range of possible outcomes to be expected, depending on how conditions unfold in future years. Scenarios with different load growth projections cannot be readily compared by total cost, as there would be an additional difference in revenues associated with the extra load. However, a comparison between Scenarios A and B and Scenarios C and D is appropriate.

Three views on costs have been prepared to help understand the impact of the scenarios and the expected changes that drive changes in the overall expansion plan: the annual partial revenue requirement, the annual partial revenue requirement normalized for in-province energy volumes which provides a view of the average cost to serve customers, and the total projected capital investment required to meet the generation needs.

Partial revenue requirement (PRR) is calculated as the total revenues to be collected through rates from in-province customers⁴³. This is also net of any miscellaneous or export revenues that help to offset the cost to New Brunswick customers. It is worth noting that this is different from the total revenue requirement presented in NB Power’s General Rate Application to the New Brunswick Energy and Utilities Board.

The PRR for each scenario is shown in Figure 5.9.

Figure 5.9: Partial Revenue Requirement by Scenario



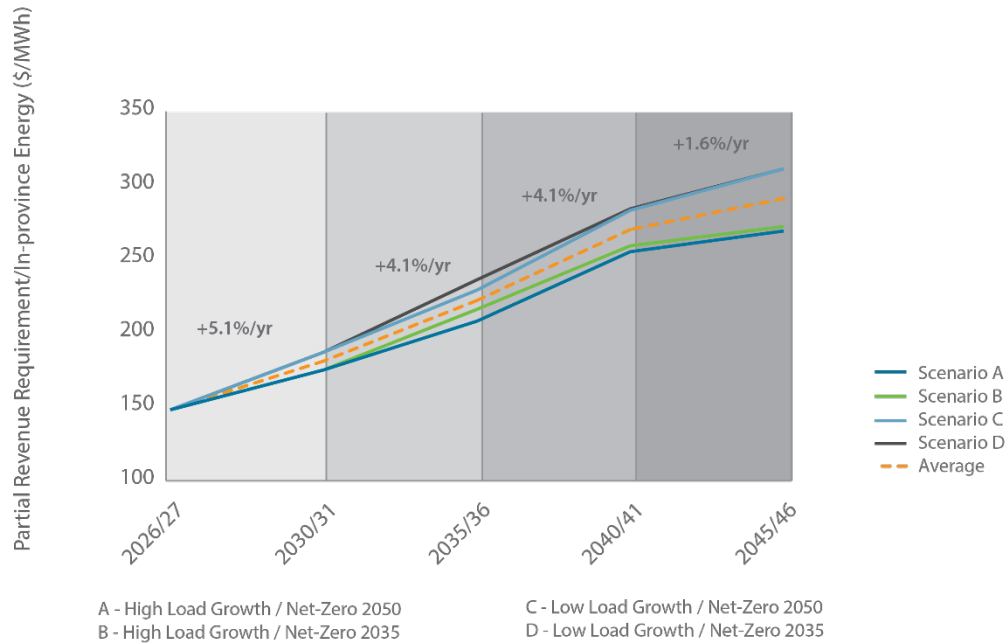
The partial revenue requirement is highest in Scenarios A and B, driven primarily by the higher loads to be served. The increase in the first five years for Scenarios C and D is driven mainly by the off-coal impacts at Belledune and increasing carbon pricing impacts. In addition, the financial sustainability of NB Power requires increased earnings to make progress toward improving the debt-to-equity ratio. Scenarios A and B see similar increases in the early years and continued increases in later years as new investments are required to meet the additional load growth.

Comparing A to B and C to D, speeding up the net-zero target will increase NB Power’s costs and increase the rate requirement, but results in some additional emission reductions.

⁴³ Note that significant transmission upgrades within New Brunswick will be required in some scenarios. These costs require further study and have not been included in this IRP.

Figure 5.10 normalizes the PRR for in-province energy sales volume, showing the average cost to serve in each year.

Figure 5.10: Average Cost to Serve (PRR /In-Prov Energy Requirements) by Scenario⁴⁴



Overall, the average cost to serve increases in the near term as we transition away from coal and see increases in carbon pricing. The Mactaquac Life Achievement Project begins to impact the results in the 2030s, putting upward pressure on costs in those periods. From 2040/41 to 2045/46, costs stabilize as the majority of the aging infrastructure has reached its assumed end of life, and already been replaced. In 2035/36 and beyond, the average costs are higher for the net-zero 2035 scenarios as expected. The high-load growth scenarios have less overall pressure on the average cost to serve. It should be noted that the majority of the growth is in high load factor industrial load, which has a lower cost to serve today and accordingly lower rates, so a lower average cost to serve will not necessarily lead to lower rates.

⁴⁴ Percentage increases are shown for the average of the four scenarios between the labelled years. For example, the 5.1 per cent annual average increase from 2026/27 to 2030/31 is equivalent to a total increase of 22 per cent.

Figure 5.11. Capital Requirements



Capital Expenditures shown above don't include planned unit builds for wind projects or the RIGS project as NB Power does not have access to those figures. The expenditures do include forecasted investments needed for existing infrastructure, including transmission and distribution assets, and existing generating stations including Mactaquac. These investments are assumed to be funded by NB Power.

New generation investments may be funded by NB Power, or NB Power may partner with a developer to procure those resources through a power purchase agreement, resulting in the upfront capital contribution from third parties. In Scenarios A and B approximately 40 per cent of the capital investment could come through this type of partnership, while in Scenarios C and D, it could be up to approximately 20 per cent. NB Power has traditionally entered into Power Purchase Agreements for new renewables and has recently entered into a tolling agreement for the RIGS facility under a similar model. Continued pursuit of such partnerships provide opportunities for effective risk management at each stage of the project, from financing through to operations.

With significant investment required across all scenarios, particularly in the late 2030s and early 2040s, NB Power will need to plan well in advance to meet these growing needs.

5.8. Net-Zero 2035

The difference between Scenarios A and B as well as Scenarios C and D is the timing of achieving a net-zero electricity system. Scenarios A and C align with existing laws and regulations in place surrounding greenhouse gas emissions, while Scenarios B and D accelerate net-zero to 2035 through additional measures to advance NB Power's transition to a clean electricity grid sooner, resulting in lower emissions and higher costs in those scenarios.

The IRP analysis does not include the broader economic and societal impacts associated with climate change, nor does it consider the impacts of revenue recycling where NB Power's contribution to NB OBPS supports decarbonization initiatives.

Comparing Scenario A to Scenario B shows a total CO₂e emission reduction over the 20-year planning horizon of 9.0 Mt at a total nominal cost difference of \$1.2 billion, an equivalent to paying \$138/tonne of CO₂e reduced. Similarly comparing Scenario C to D results in a total CO₂e emission reduction of 5.7 Mt at a total nominal cost difference of \$0.6 billion, an equivalent to paying \$106/tonne of CO₂e reduced.

Existing laws and regulations surrounding greenhouse gas emissions are resulting in emission decreases in the range of 90 to 96 per cent from 2005 levels under the net-zero 2050 Scenarios. Accelerating the pace of decarbonization to achieve a net-zero electricity system by 2035 will increase costs and put additional pressure on rates.

6. Sensitivity Analysis

The objective of the sensitivity analysis is to highlight the role that major projects may play in the future as well as identify key risks. Exploring sensitivities provides additional insight into questions based on what-if scenarios that can potentially have a large impact on the electricity system in the future. NB Power acknowledges that to decarbonize the electricity grid and provide long-term energy security, large-scale investments will be required to replace aging infrastructure. As such, three themes have been chosen for the sensitivity analysis

- the role of nuclear
- increasing transmission interconnections
- understanding the impacts of existing laws and regulations surrounding greenhouse gas emissions

With the growth in demand for electricity, nuclear has recently seen a resurgence in popularity. Exploring the different options for nuclear provides a complete picture of what the electricity system in New Brunswick could look like in the future with the retirement of nuclear as well as the addition of new nuclear.

Given the current federal government's interest in energy and discussions to remove barriers to transmit energy across the country, this IRP explores increasing the capacity of interconnections to better understand what role New Brunswick could play in being an energy hub for Atlantic Canada.

Lastly, one of the predominate themes of this IRP is to explore different pathways to achieving a net-zero electricity system. Exploring a sensitivity with no carbon restrictions provides a fulsome picture on the impacts of achieving net-zero by providing the counterfactual, painting a more complete picture when considering options on the pace of decarbonization.

6.1. No Nuclear Sensitivity

The Point Lepreau Nuclear Generating Station provides carbon-free energy and capacity to the New Brunswick grid. Approximately one-third of all electricity produced in New Brunswick comes from this facility.

The site license for current operation is for 210,000 effective power hours, from the refurbishment which would take the facility to 2041/42. There are considerable uncertainties in the end-of-life plans for the station that require decisions. These options include

- retirement of the station
- life extension of the station
- refurbishment of the station

The base scenarios, as shown in Section 5, assume a life extension of the facility to 2047/48, beyond the planning horizon of this analysis.

The NB Power grid has been designed with a large nuclear generator as a significant producer of energy and capacity and removing this large generator would require major changes to the NB Power electricity grid. Additionally, an investment in new nuclear generation or refurbishment would require a large capital commitment or a large financial commitment over time in the case of a PPA and tie NB Power to a specific technology for decades. Given this commitment it is important for NB Power and policy makers to have a fulsome understanding of the costs and implications of a system with or without nuclear generation. This sensitivity will review how NB Power would replace Point Lepreau Nuclear Generating Station should it not be replaced or extended when it is due for retirement and how this would impact the generation mix in the province.

Strategic decisions surrounding life extension, a second refurbishment and or a new build are required to be made with initial support organizations established within the next five-year period; translating to required business case development within the next three-year period.

Life extensions have been successfully pursued by all other Deuterium Uranium (CANDU) units in Ontario⁴⁵. A decision to extend the life at PLNGS would require an application and approval with the Canadian Nuclear Safety Commission (CNSC). The timeframe under which an extension would typically be pursued is in the range of 5-10 years before end of life. NB Power is currently working towards completing the necessary engineering studies and analysis that could support this extension application to the CNSC.

⁴⁵ *Regulatory Oversight Report for Nuclear Power Generating Sites: 2018*, <https://www.cnsccsn.gc.ca/eng/reactors/regulating-nuclear-reactors-power-plants/regulatory-oversight-reports/canadian-nuclear-power-generating-sites/npgs-report-2018/>

The No Nuclear Sensitivity will help NB Power understand how NB Power's system would adapt and what replacement resources would be required. Comparing the No Nuclear Sensitivity costs to the costs of the base scenarios will give insight into the value that existing nuclear brings to the electricity system and help to inform the work around potential future life extensions.

Approach and Assumptions

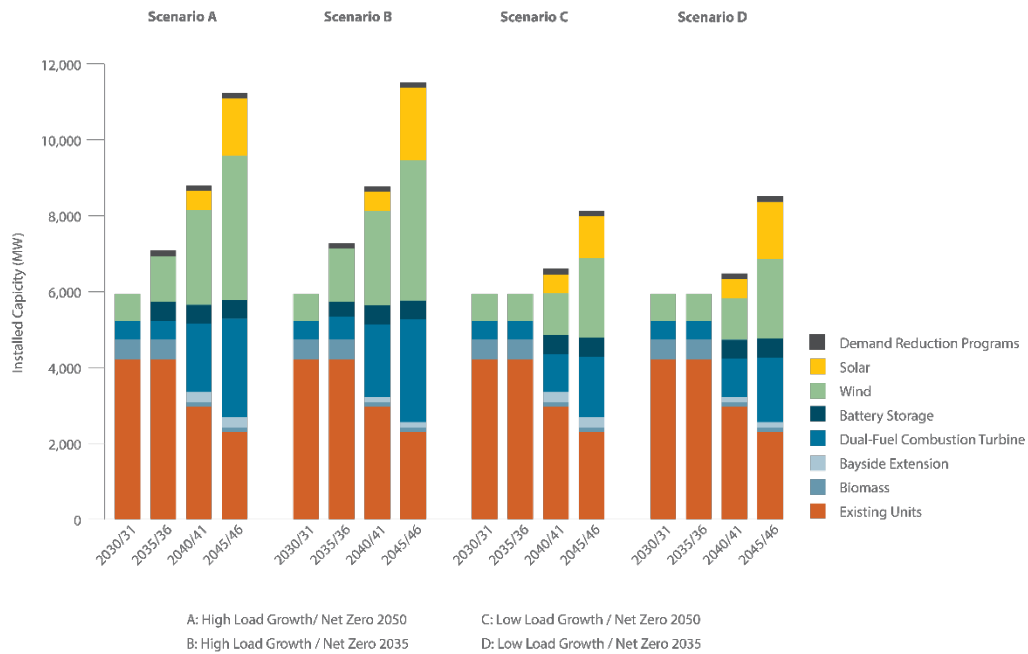
The goal of this sensitivity is to explore the conservative scenario of only achieving 210,000 equivalent operating hours, resulting in a retirement of Point Lepreau Nuclear Generating Station within the 20-year IRP planning horizon and understanding the gap that would be created in the NB Power system. This sensitivity is not intended to be interpreted as NB Power's preferred plan, but it will help inform the discussion around the role and value of nuclear on the New Brunswick grid and what alternatives might be considered in the absence of nuclear. It will help guide the discussion around life extensions and potential future refurbishment.

The primary assumption change will be that the generator at Point Lepreau Nuclear Generating Station will retire at the end of fiscal year 2041/42, a conservative target date for achieving 210,000 equivalent operating hours. No new nuclear units will be added to the system and the results will be compared against the four base scenarios to showcase the impacts of early retirement.

Results and Discussion

The results show that nuclear is not replaced with any one generation technology. Rather, a suite of combustion turbines, wind and solar to fill the gap of energy and capacity created by retiring Point Lepreau Nuclear Generating Station, as shown in 2045/46 fiscal year in Figure 6.1. The detailed capacity expansion plan for this sensitivity can be found within Appendix I – Expansion Tables.

Figure 6.1: Installed Capacity – No Nuclear Scenarios



Significant investment is required to build new resources to replace the generation gap left by the retirement of Point Lepreau Nuclear Generating Station (663 MW) as follows:

Scenarios A, B and D build between 1,500 – 1,800 MW of additional renewables over and above the base case scenarios to help meet the energy need, and 600 – 700 MW of combustion turbines to meet the capacity requirement.

In Scenario C, the Bayside Generating Station is life-extended as a combined-cycle plant which provides both energy and capacity to the grid. This reduces the additional renewable build out slightly.

Overall, the total installed capacity to replace Point Lepreau Nuclear Generating Station with a combination of combustion turbines and renewables ranges from 2,200 – 2,500 MW which equates to an effective firm capacity of 650 - 745 MW. Additional wind and solar are accompanied by additional dispatchable resources across all scenarios to help balance the generation with load.

Figure 6.2: Energy Balance – No Nuclear Scenarios

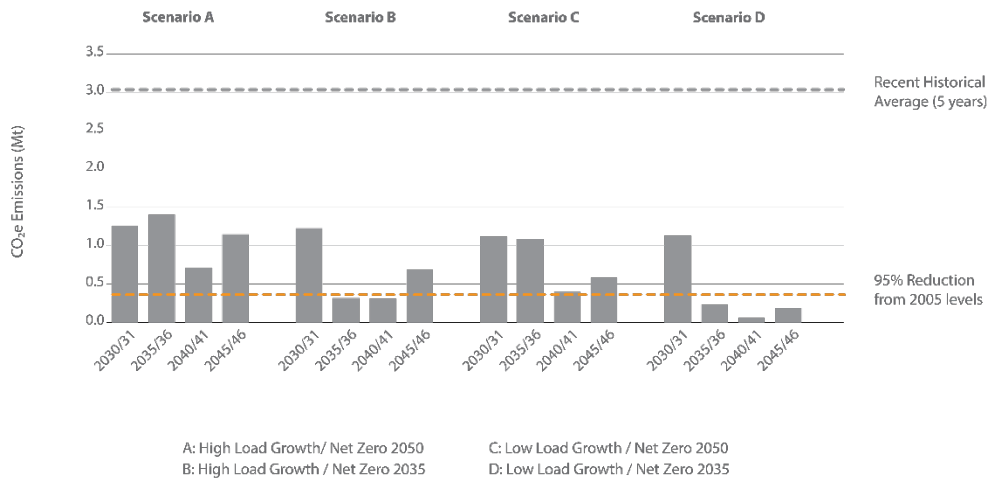


As shown in Figure 6.2, the majority of the energy requirements are filled in by renewables with some additional energy required by emitting resources and imports to provide reliability and grid services. For instance, solar and wind help to fill the gaps, though there is significantly more variability compared to a base-loaded nuclear facility. This creates a need for additional grid services (e.g. providing ramping and regulation) from dispatchable units to keep the system in balance.

When comparing the emissions in Figure 6.3 for the No Nuclear Sensitivity against the base scenarios in Figure 5.6, the emissions are nearly the same prior to the retirement of Point Lepreau Nuclear Generating Station. When the assumed end of life for Point Lepreau Nuclear Generating Station occurs in 2041/42, there is a noticeable increase in emissions for the no nuclear sensitivity across all four scenarios compared to the base scenarios.

The results show that without nuclear, Scenario D is the only case to achieve net-zero before 2050. Scenario B does not achieve net-zero after the assumed end of life of Point Lepreau Nuclear Generating Station despite additional carbon restrictions. This indicates that additional interventions beyond what was modeled may be required to achieve a net-zero electricity system without nuclear generation in the province.

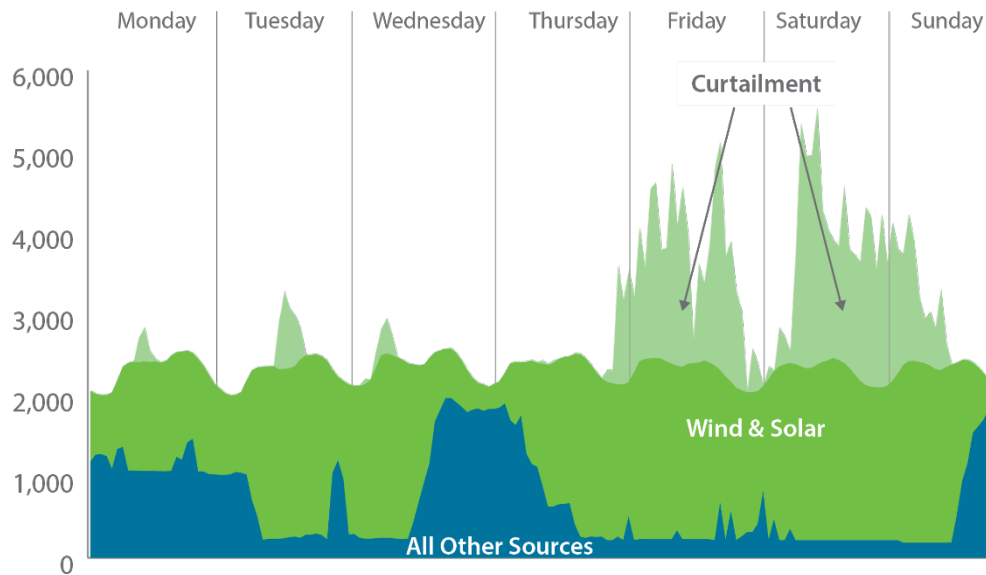
Figure 6.3: GHG Emissions – No Nuclear Scenarios



This scale and scope of variable renewable penetration is much higher than the base scenarios. The complexities of transmission constraints, voltage and frequency control require operational studies to determine how the variability and forecast error may impact operations and reliability.

Figure 6.4 shows the forecasted variability of wind and solar over a week in October 2042 for Scenario B for the No Nuclear Sensitivity. Contrasting this with Figure 5.8, two items stand out. First, the variability of the 'other resources' as shown in Figure 6.4 has increased significantly while the overall volume of energy from these sources has declined. This means that the balance of the system will require more flexibility while operating at lower generation levels of dispatchable generation. Second, the volume of curtailments has increased up to 3,100 MW in some hours. This highlights the need to build control and the ability to curtail into future wind and solar power purchase agreements.

Figure 6.4: Hourly Generation for Oct 2045 Scenario B, No Nuclear Sensitivity



Existing nuclear has a significant role and adds tremendous value to the system. Comparing total system costs with and without Point Lepreau Nuclear Generating Station, while excluding the fixed costs associated with the extension of Point Lepreau Nuclear Generating Station and the operational cost assumptions like regular capital, operations and maintenance, provides a picture of the total value that nuclear generation brings to the system. This value is approximately \$900 million in potential benefits annually, varying slightly for each scenario. Investment in Point Lepreau Nuclear Generating Station is currently expected to average \$600 million annually in those extension years.

NB Power recognizes the significant opportunity associated with the potential life extension of Point Lepreau Nuclear Generating Station, and will commit to continued detailed analysis to support future decisions on life extension and refurbishment opportunities.

6.2. New Nuclear Sensitivity

The addition of increased nuclear generation in New Brunswick would allow nuclear power to continue to provide stable and increased reliable baseload, carbon-free electricity and enhance New Brunswick's energy security. This new nuclear capacity would support NB Power's Strategic Plan to transition to a cost-effective, clean and secure energy supply. Energy security is especially important as New Brunswick looks to increase economic development in the province through a period of uncertain load growth.

Nuclear generation is an economic development opportunity, due to an extended planning/construction window, supply chain opportunities and subsequent plant operation for its extended lifetime of 60 years, creating a significant economic benefit to New Brunswickers. NB Power has a nuclear operating pedigree and a licensed nuclear site at Point Lepreau Nuclear Generating Station with room for expansion.

In addition to providing energy security for New Brunswick, the deployment of new nuclear could support regional electricity partnerships. New Brunswick's location and transmission interconnection system puts us in a unique geographical location within our region. New nuclear with regional arrangements would support a reduction in reliance on fossil fuels and complement the existing and planned renewable generation in neighbouring jurisdictions.

The impact assessment, licensing, and construction of nuclear facilities can take up to 10-14 years and would need to be initiated in the near future, to ensure availability to meet the projected timelines. As has been done elsewhere in Canada, the impact assessment process and first stage of the new nuclear licensing process can be initiated prior to selecting a technology and can be bounded by a maximum expected generation output. During the early stages of these processes, an appropriate technology can then be chosen that is best suited to meet New Brunswick's needs and support potential regional electricity cooperation efforts.

Nuclear generation requires significant capital commitments. Given this commitment it is important for NB Power and policy makers to have a fulsome understanding of the costs and implications of a system that continues with nuclear generation. This sensitivity will review how NB Power would double its nuclear generation capacity and how the future of the Point Lepreau Nuclear Generating Station may interact with this future.

This sensitivity also impacts NB Power's decisions around nuclear, whether those be new builds, refurbishments or retirements, which typically are made 15 to 20 years in advance. Significant planning and preliminary work are required to ensure energy security through any changes in the nuclear fleet.

Approach and Assumptions

The purpose of this is not to predetermine a set volume of nuclear but to identify what in the expansion plan would change and to understand the changes in total system and capital costs between the sensitivity scenarios and the base scenarios. This will then allow NB Power and policy makers to determine the value that would need to be considered when making a decision around new nuclear.

The specific changes to IRP key assumptions that were modeled for this sensitivity include

1. add new nuclear generation of 750 MW in fiscal year 2039/40. This allows a reasonable amount of time to cover off any risks around Point Lepreau Nuclear Generating Station's end of life as well as any risks around the construction of new nuclear being delayed
2. add additional new nuclear generation of 750 MW in fiscal year 2044/45. This could be either the refurbishment of Point Lepreau Nuclear Generating Station, or the retirement of the Station and build a second new unit
3. create a new energy and capacity sale of 500 MW starting in fiscal year 2044/45

It is assumed that the new nuclear would be co-located with Point Lepreau Nuclear Generating Station and will require upgrades to existing transmission infrastructure.

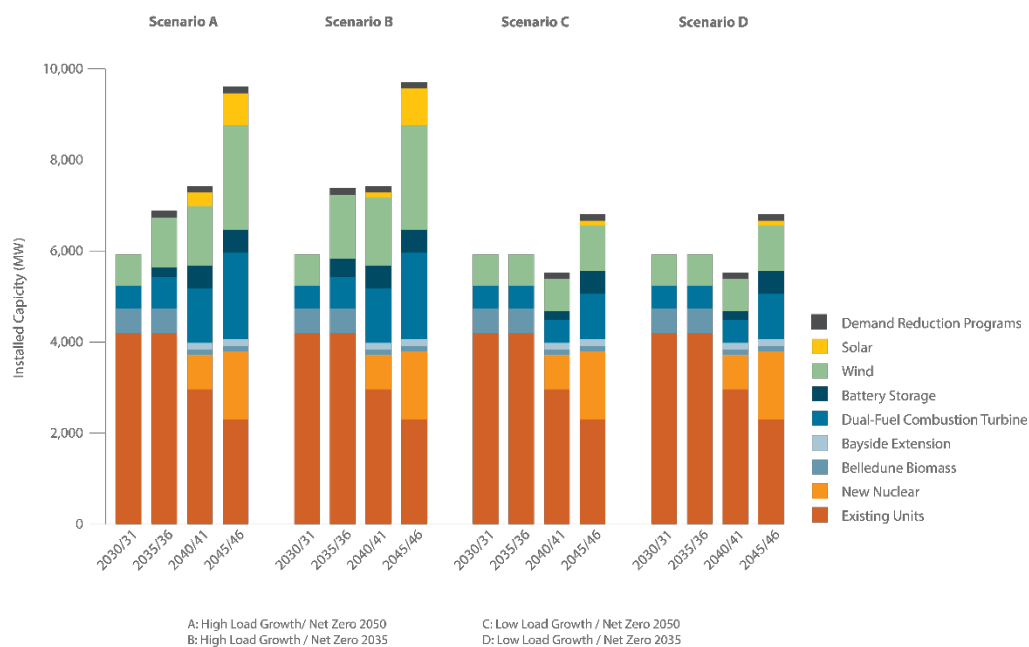
No changes to any policy, fuel or technology costs will be made in this sensitivity. This will allow comparison of the sensitivities against other scenarios or sensitivities established solely on the changes to nuclear generation roll out.

Results and Discussion

The opportunity presented from new nuclear is energy security in New Brunswick by providing large volumes of reliable, carbon-free, high capacity factor (baseload) generation. This could result in New Brunswick being a net exporter of energy and can be a hedge against electricity and fuel markets. Leveraging infrastructure at an existing facility also minimizes the impact of additional land use. The challenge in pursuing new nuclear is that a larger proportion of the generating fleet is one technology. This can result in reduced flexibility when operating the grid and increased dependency on just a few large resources for energy security.

The results in Figure 6.5 show for all four scenarios, adding 750 MW of nuclear installed capacity in years 2039/40 and 2044/45 to the system significantly displaces the need for other resources. The detailed expansion plan for this sensitivity can be found in Appendix I – Expansion Tables.

Figure 6.5: Installed Capacity – New Nuclear Scenarios



Compared to the base scenarios, the expansion plans for the New Nuclear Sensitivity build considerably less wind and solar as well as slightly less combustion turbine capacity. In all four of the New Nuclear Sensitivity scenarios, there are also delays in battery roll out from the base scenarios.

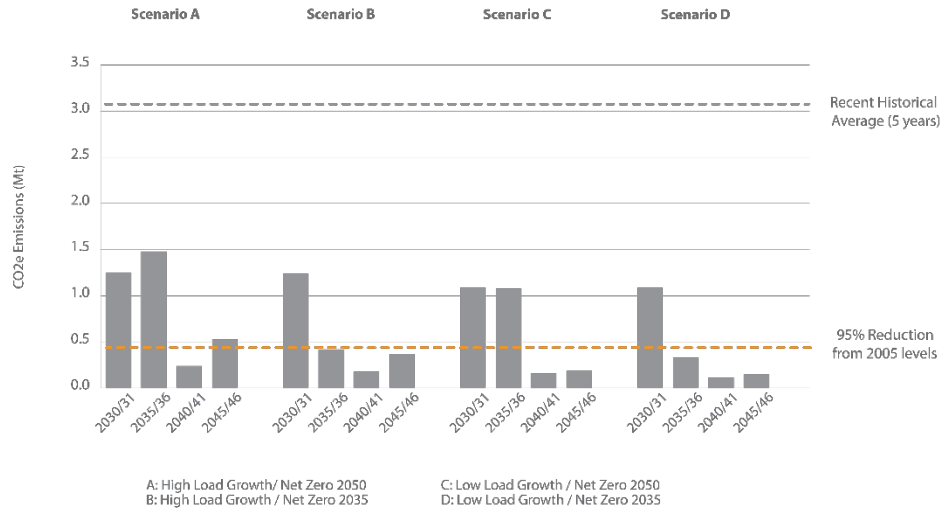
The addition of nuclear provides large volumes of reliable energy with very little dependency on other resources in comparison with the base scenario. As shown in Figure 6.6, the energy supplied by new nuclear displaces an array of resources with the majority being renewable and imports. In 2045/46, there is a noticeable increase in exports across all scenarios associated with the 500 MW export contract assumed to begin in 2044/45.

Figure 6.6: Energy Balance – New Nuclear Scenarios



The results show that with the addition of new nuclear to the system, a net-zero electricity system is achieved in the 2040s across all scenarios with no additional interventions required.

Figure 6.7: GHG Emissions – New Nuclear Scenarios



New nuclear has the potential to create significant opportunities for partnerships or regional cooperation. Of the 1,500 MW included in the analysis, 500 MW is assumed to be part of a regional partnership. This could create economies of scale or potentially a fleet of similar units to help lower overall costs.

In addition, 1,000 MW of new nuclear for use in New Brunswick would offset investments in other generation assets as well as reduce total fuel and purchased power costs. This value is estimated to be more than \$1 billion annually, before consideration of the direct nuclear-fixed costs, operations and maintenance costs and required transmission upgrades. This provides a significant benefit to offset the investment that would be required but more information is needed to determine if this potential future is in the best interest of New Brunswickers.

Such an analysis would need to consider the latest estimates for building and operating nuclear assets, further development on partnership opportunities, more detailed studies on the transmission infrastructure needs and costs, detailed risk analysis and any government support that may be provided. NB Power is committed to understanding these factors and will make informed decisions as major milestones arise in the coming years.

6.3. Increased Interconnection Sensitivity

NB Power has benefited from a robust transmission system with strong connections to its neighbors for several years. As the electricity sector transitions to renewable and carbon free resources, utilities have been exploring additional investment in infrastructure to transmit large volumes of energy. This IRP explores the option of significantly increasing the capacity of interconnections to better understand the role that transmission could have in the transition to a net-zero electricity system. The purpose of this sensitivity is to gain insight into how New Brunswick could optimize building its own resources with purchases from neighbouring jurisdictions and better understand what role New Brunswick could play in being the Energy Hub for Atlantic Canada.

Approach and Assumptions

This sensitivity increases the total import and export capacity by a total of 1,000 MW. It is assumed the increased capacity to interfaces becomes available in 2035/36 and that its intended use is for energy only (i.e. it is assumed that NB Power will not be able to purchase firm capacity over this interface).

The modelling of this sensitivity did not consider any new firm capacity obligations or power purchase agreements outside of those considered in the base scenarios. This is consistent and aligns with long-term assumptions. The objective of this sensitivity is to analyze the utilization of increased import and export capability if it were available in the future. Assumptions include current market pricing for both imports and exports. It is also assumed that there are no restrictions on the volume of imports available, though it is recognized that this may be a significant barrier in practice.

An estimate of the cost of the required transmission upgrades to facilitate the flow of an additional 1,000 MW has not been completed. However, it is expected to be multiple billions of dollars. The recent Atlantic Loop project, for example had cost estimates in the range of \$6-9 billion for adding 1,150 MW of transmission capacity into the region.

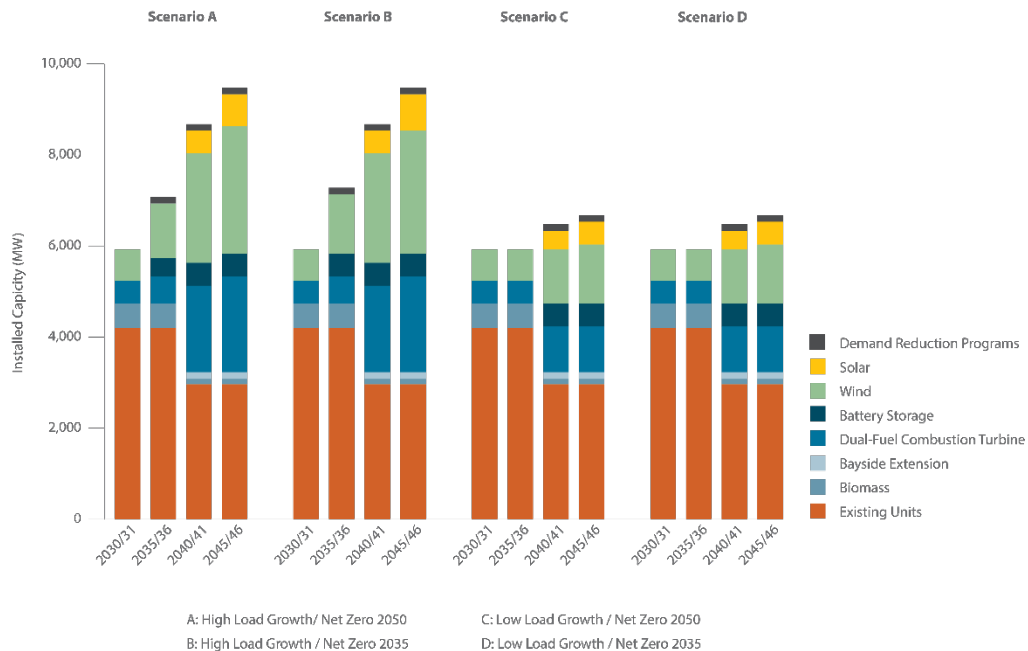
Results and Discussion

Increasing the capacity of interconnections provides opportunities such as improved system reliability and removes barriers to transmitting large volumes of energy which allows jurisdictions to share resources with neighbours at a much larger scale. Challenges associated with increasing the capacity of interconnections could potentially impact energy security within New Brunswick.

If New Brunswick is in the position of being a net importer of energy, this increases the dependency on other jurisdictions to supply New Brunswick customers. The risk becomes the reliability of the source of energy from the neighboring area and the reliability of the infrastructure used to transmit that energy across long distances. For example, transmission infrastructure has increased exposure to extreme weather events such as forest fires, hurricanes and ice storms.

The results of increasing the interconnection capability in Figure 6.8 shows an overall decrease in the installed capacity for the high load growth Scenarios A and B compared to the base scenarios with minimal differences in the low load growth Scenarios C and D. Scenario B shows a substantial decrease in solar installed capacity as the model chooses to import more energy rather than source from in-province resources. The detailed capacity expansion plan for this sensitivity can be found within Appendix I – Expansion Tables.

Figure 6.8: Installed Capacity – Increased Interconnections Scenarios



The energy balance (Figure 6.9) shows both increased imports and increased exports enabled by the additional transmission capacity. More renewable generation is also enabled with increased transmission capacity by reducing the curtailment of those resources.

For example, in 2045/46 in Scenario A, the curtailment of renewable generation is reduced by over 1,000 GWh. This leads to more renewable generation being produced despite lower total renewable installation relative to the corresponding base scenario. The increased transmission capacity leads to higher imports and exports but does not have a high utilization rate. The utilization rate is the proportion of transfer capacity used for imports as well as exports. The additional transmission capacity increases imports by approximately 1,500 GWh annually in the high load scenarios but only approximately 350 GWh annually in the low load scenarios. Exports are also increased by approximately 800 GWh annually in the high load scenarios but only approximately 600 GWh annually in the low load scenarios.

Overall, this is a total utilization rate of 26 per cent in the high load scenarios and only 7 per cent in the low load scenarios.

Figure 6.9: Energy Balance – Increased Interconnection Scenarios



The result of increasing the capacity of interconnections by 1,000 MW in 2035/36 shows that in-province emissions are reduced across all scenarios below the 95 per cent reduction levels of 2005 to achieve net-zero, with only slight differences in timing.

Figure 6.10: GHG Emissions – Increased Interconnections Scenarios

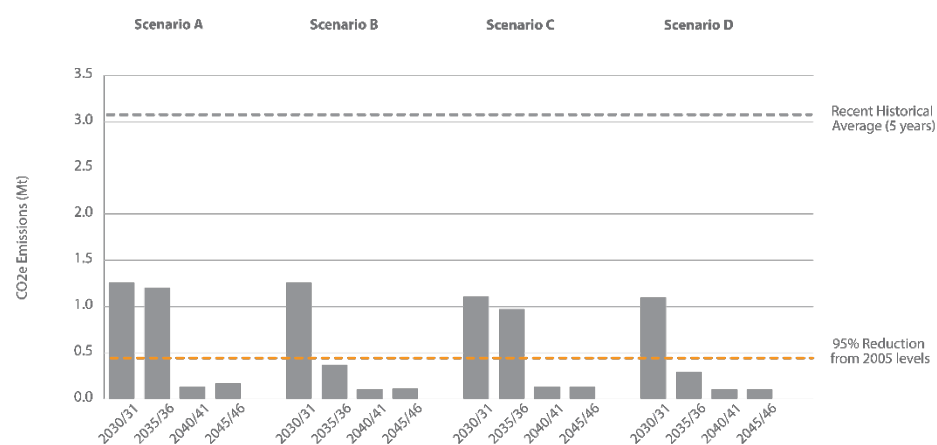
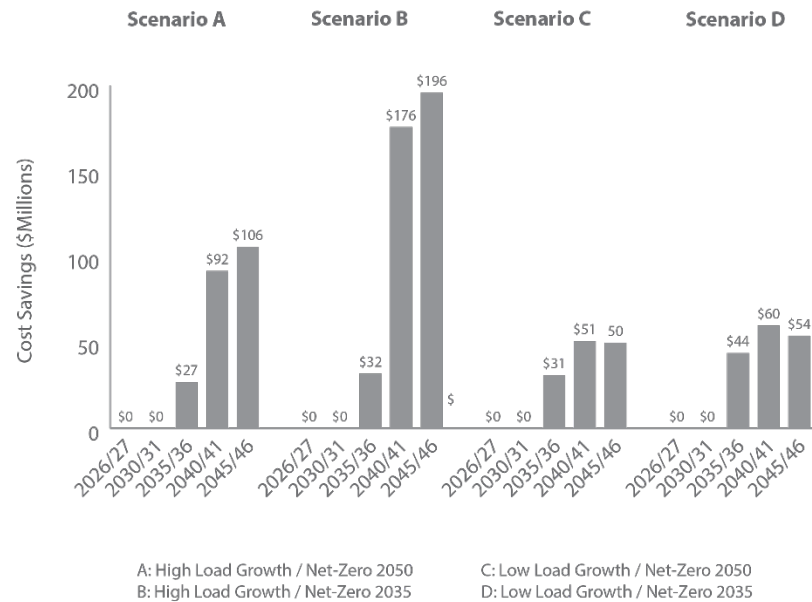


Figure 6.11 shows the total opportunity of the increased interconnection capacity without any of the infrastructure costs. No specific transmission project design or engineering has been completed on this opportunity. However, New Brunswick has a relatively small electricity system and the cost is likely in the range of multiple billions of dollars. The value of this proposition is likely to increase when forming strategic partnerships with neighbouring areas to transmit energy to the region.

Figure 6.11: Gross cost savings from increased transmission interconnection (excluding Increased Interconnection Capital Costs)



6.4. No Carbon Restriction

NB Power acknowledges the risk of climate change and is working diligently to decarbonize the electricity system. The 2026 IRP explores the rate and impact of decarbonization of New Brunswick's electricity system. In the base scenarios, NB Power explores pathways for achieving a net-zero electricity system by 2035 as well as a gradual rate of achieving net-zero by 2050. The No Carbon Restriction Sensitivity was designed to better understand the impacts of the existing laws and regulations surrounding greenhouse gas emissions including their effectiveness in reducing emissions as well as the associated costs. The results of this sensitivity will provide decision makers insight with respect to the effectiveness and cost of existing laws and regulations.

Approach and Assumptions

This sensitivity explores the option that removes the restrictions existing laws and regulations impose on greenhouse gas emissions, effectively allowing unabated emissions from fossil fuel generation. This sensitivity removes all carbon restrictions, so only a high load growth and low load growth scenario were run. In understanding the impacts of the existing laws and regulations, it is best compared against the net-zero 2050 scenarios (A and C). The sensitivity analysis includes

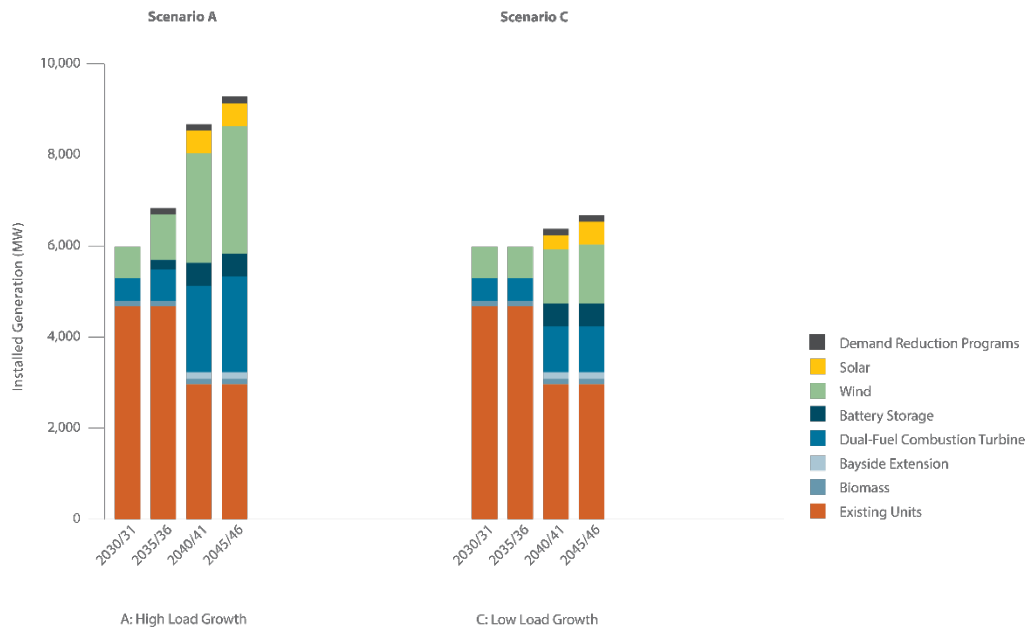
- removal of the output-based pricing system and associated carbon pricing
- removal of all emission constraints from fossil fuel generation
- removal of coal being phased out in 2030
- allowance of Belledune to continue using coal through to its retirement date

This analysis does not include the broader economic and societal impacts associated with climate change, nor does it consider the impacts of revenue recycling where NB Power's contribution to NB OBPS supports decarbonization initiatives.

Results and Discussion

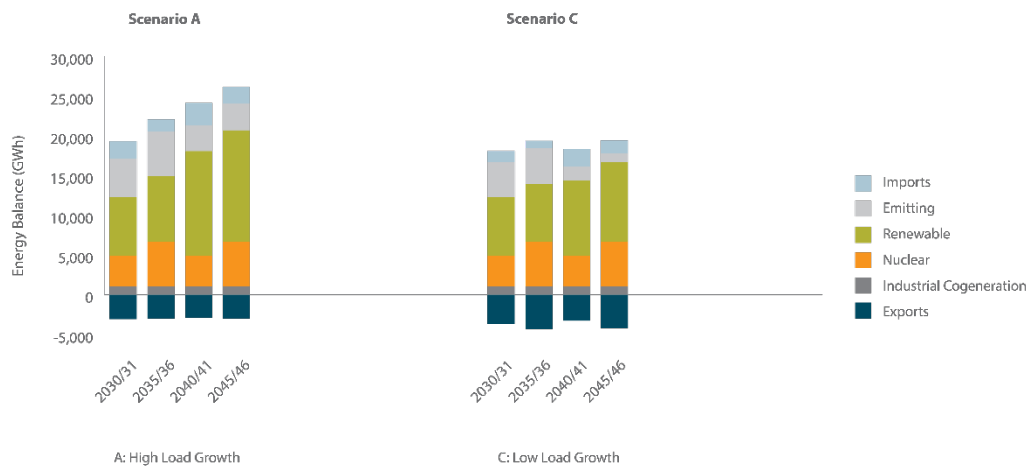
The changes to installed capacity for the No Carbon Restriction Sensitivity show that Belledune would continue to operate on coal and the conversion to biomass would not occur. Scenario A also shows additional combustion turbines being selected. In both scenarios, investments in batteries, solar and wind would not occur when compared to the base scenarios. The detailed capacity expansion plan for this sensitivity can be found within Appendix I – Expansion Tables.

Figure 6.12: Installed Capacity – No Carbon Restriction Scenarios



The results of the no carbon restriction sensitivity for both scenario A and C clearly show the balance of energy requirements compared to the base scenario being supplied entirely by emitting resources instead of carbon-free resources such as renewables, batteries and imports.

Figure 6.13: Energy Balance – No Carbon Restriction Scenarios



The overall impact from the No Carbon Restriction Sensitivity shows an increase in emissions with Scenario A not achieving net-zero during the study period (though still making meaningful progress) and Scenario C achieving net-zero emissions only in the final years of the planning horizon.

With no carbon restrictions, emissions would be substantially higher as Belledune continues to operate on coal through the 2030s. Also, the assumed end of life for NB Power's largest fossil fuel generating stations Coleson Cove and Belledune in 2040/41 have the largest impact on reducing emissions. The balance of emitting resources in the system after 2040/41 are natural gas peaking units with relatively low-capacity factor projections, leading to a significant reduction in emissions in the 2040s relative to recent history even in the absence of any carbon restrictions to drive reductions.

Figure 6.14: GHG Emissions - No Carbon Restrictions

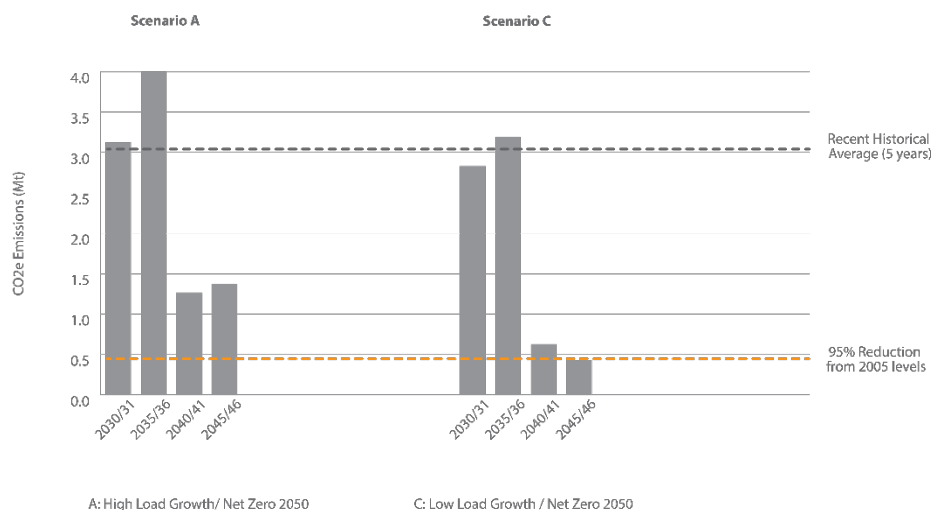
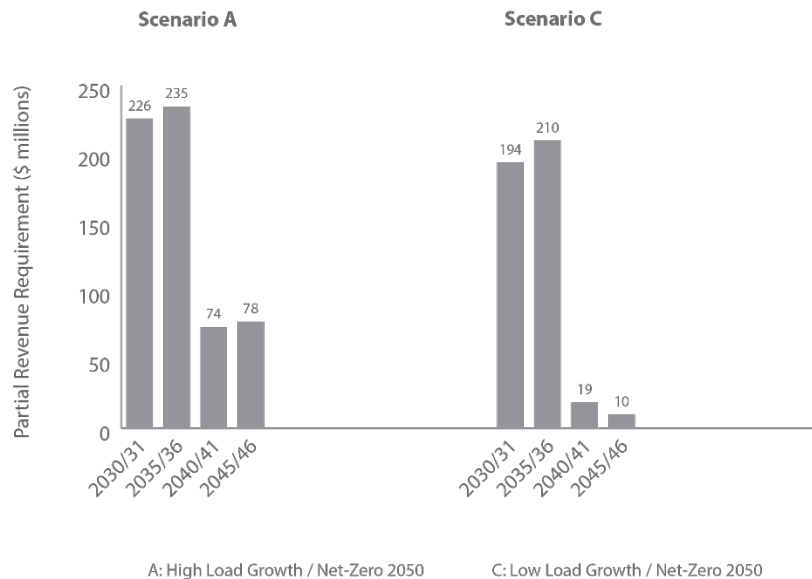


Figure 6.15 shows the cost difference between the No Carbon Restriction Sensitivity and the base scenarios. The difference in costs is driven mostly by the off-coal regulation with significantly higher costs in the 2030s. In the 2040s, the high load growth (scenario A) comparison has a reasonably high-cost delta mostly attributed to the carbon price on the remaining natural gas generation facilities in the Base Scenario A.

In the low load growth (scenario C) comparison, the difference shrinks considerably as the capacity factor of the remaining natural gas facilities is low.

Figure 6.15: Cost of Existing Laws and Regulations Surrounding Greenhouse Gas Emissions



The total emissions in the Base Scenarios are lower than the No Carbon Restrictions Sensitivity by 29 Mt (scenario A comparison) and 24 Mt (scenario C comparison) over the 20-year planning horizon. These emission reductions are the result of existing laws and regulations. The increase in cost over the planning period is (nominal) \$3.2 billion and \$2.5 billion for the Scenario A and Scenario C comparisons respectively. Most of these costs and emission reductions are due to the phase-out of coal at Belledune in 2030. From 2026/27 to 2030/31, the partial revenue requirement per unit of energy sold over the period is expected to increase by 5.1 per cent annually (refer to Figure 5.10). Within this period, approximately two per cent annually is related to existing laws and regulations of greenhouse gas emissions.

These values help provide the overall cost of carbon reduction resulting from the existing laws and regulations in place surrounding greenhouse gas emissions. For the Scenario A and Scenario C comparisons, removing CO₂e emissions comes at a cost of \$110/tonne and \$104/tonne respectively.

7. Conclusion

Electricity impacts everything we do. The direction we set today will impact the next generation. An affordable, clean and reliable electricity system is a foundational driver in positioning New Brunswick for long-term growth in a changing energy landscape. This integrated resource plan navigates uncertainty to provide various pathways to a resilient electricity system for the future.

7.1. Common Actions

NB Power is undertaking a number of investments in its future. These include power purchase agreements for 702 MW of new wind generation, 500 MW tolling agreement for new dual-fueled combustion turbine capacity, a conversion of Belledune to biomass, and investments in a new transmission line between New Brunswick and Nova Scotia.

Across all four base scenarios, the model selects the same types of resources to build. The recommended portfolio of generation includes wind, solar, combustion turbines, batteries, demand response and a life extension of Bayside. The difference between the scenarios is in the amount of generation resources as well as the timing of when resources are required. The results of the IRP provide assurance and validation of NB Power's strategic plan to provide clean, competitive and reliable energy solutions. The common actions identified across all base scenarios are no regret investments that NB Power should continue to pursue. A summary of these common actions is shown in Table 7.1.

Table 7.1: Summary of Common Actions Across Base Scenarios

Installed Generation	Technology
500-1,600 MW	Combustion turbines
410 MW	Belledune biomass
150-270 MW	Bayside extension
500 MW	Batteries
146 MW	Demand response
400-2,100 MW	Wind
500-1,500 MW	Solar

New wind and solar are always supported by an addition of some sort of dispatchable resource (typically batteries or combustion turbines) to help integrate the renewables and maintain reliability.

The lead time to many of these projects is in the range of 3-5 years from inception to in-service date. There is an opportunity to mature projects prior to their expected in-service date so they are in a more advanced state and can meet an accelerated need if it were to arise.

7.2. Planning for Uncertainty

The electricity industry is experiencing a great deal of uncertainty. It is prudent for NB Power to consider several pathways that address uncertainty when planning a system for the future. A reoccurring theme in the IRP has been focused on the core principle of risk management. Managing risk appropriately can provide protection for environmental and economic sustainability, as well as reliability. NB Power intentionally chooses a scenario-based approach with the IRP to provide insight into what to do and when, as conditions continue to change.

By continuously monitoring the changing energy landscape, decision-makers can refer to the IRP for information before they plan to act. For example, signposts or triggers to look for occur when there is a deviation from the key assumptions in the IRP. This could include material changes such as

- variation in load compared to the load forecast
- changes to existing generating resources such as a premature failure or significant change in assumed end of life date
- substantial changes in laws, regulation or standards
- changes in operating conditions such as firm imports or exports
- significant change in markets such as supply chain disruptions

The results of the IRP high-load growth scenarios show that the amount of energy could increase by over 50 per cent over the next twenty years. The likelihood of high load occurring is probable given the several contributing factors that may increase load growth. Comparing the high load growth scenarios (A and B) to the low load growth scenarios (C and D) provides insight into what are the most economic options for responding to growth. They include

1. acceleration of battery storage
2. acceleration of demand response programs
3. higher total volume and acceleration of wind
4. higher total volume and acceleration of solar
5. higher total volume of acceleration of combustion turbines

The timelines under which resources can be procured and built also must be considered, with the lead times in the 3-5 year range at a minimum, with considerably longer lead times in recent years due to supply chain pressures for certain technologies.

NB Power is committed to reducing its emissions to achieve a net-zero electricity system. NB Power has already made significant progress in reducing its emissions by 65 per cent from 2005 levels and is expected to continue to reduce emissions significantly in the coming years. As we march toward achieving a net-zero electricity system, NB Power acknowledges there is uncertainty with laws and regulations surrounding greenhouse gas emissions. For example, the government may decide to update the OBPS pricing system.

Comparing the net-zero 2035 scenarios to the net-zero 2050 scenarios provides insight into the impacts on the pace of decarbonization in the electricity system. Accelerating the achievement of a net-zero electricity system in 2035 will reduce emissions in the years after 2035 but will also increase the cost to serve New Brunswickers. Most of these costs and emission reductions are due to the phase-out of coal at Belledune in 2030.

As NB Power continues its journey to net-zero, it is beneficial to understand how effective the existing laws and regulations surrounding greenhouse gas emissions are in reducing emissions. The results of the No Carbon Restriction Sensitivity show the impact of phasing out coal has the biggest effect on reducing emissions. Overall, the existing laws and regulations will result in reducing emissions by 29-34 Mt over the 20-year planning horizon at a cost of \$2.5-\$3.2 billion (nominal).

The future of nuclear in Canada's electricity system has recently been a key topic of discussion in energy strategy. The IRP explored different scenarios for nuclear including life extension of Point Lepreau Nuclear Generating Station, retirement of nuclear as well as the addition of new nuclear. Nuclear provides significant value to the system by supplying almost one third of in-province energy and capacity requirements with no emissions. A system without nuclear would require a significant amount of renewables and combustion turbines to fill this gap.

Results show that without nuclear, emissions would increase due to the requirement for combustion turbines to provide capacity and grid services. The financial analysis shows that there is tremendous value in extending the life of the Point Lepreau Nuclear Generating Station. The overall value this unit brings to the system is projected to average approximately \$900 million annually during the period of the extension. The overall benefits currently are projected to outpace the costs, however, deeper consideration for this opportunity will need to occur in the coming years to better understand both the technical viability and economics of life-extending Point Lepreau Nuclear Generating Station.

New Nuclear is another opportunity for New Brunswick. Under the New Nuclear Sensitivity, the total nuclear capacity in New Brunswick increases to 1,500 MW with a 500 MW export opportunity assumed. This opportunity could help regional decarbonization goals and could also provide economies of scale to the New Brunswick nuclear industry.

The net impact is 1,000 MW of nuclear energy and capacity made available to New Brunswick. This provides an overall value to New Brunswick of more than \$1 billion annually, before considering the fixed and operational costs related to the nuclear capacity and energy in those years. This represents a significant opportunity, but more work is required to understand the costs and risks associated with new nuclear projects.

Increasing interconnections with neighbours and breaking down some of the congestion will enable more imports and exports and could be a benefit to New Brunswickers. The opportunity from an overall generation resource mix is in the range of \$50-\$200 million annually. This doesn't consider the costs of such upgrades, nor does it consider any additional benefits or revenues from external parties utilizing the infrastructure. The combination of these factors could create the conditions for a worthwhile investment, but it is again an area that would require more study.

7.3. Key Takeaways

Resource Selection

Wind and solar are key sources of energy across all scenarios and sensitivities. The value of these resources to the system has diminishing returns, but optimizing investment in these resources will help lower overall costs and increase renewable generation. Combustion turbines, battery storage and demand response programs are key sources of capacity selected across all scenarios and sensitivities. Battery storage and demand response programs are limited by declining ELCC values, but the first tranche of resources provides value. Capacity resources keep the electricity system reliable and are built to meet growing needs or to replace existing resources that retire.

The life extension of Bayside is also a key resource selected across all scenarios and sensitivities. In some cases, it is extended as a combined-cycle facility, while in others it is converted to a simple-cycle facility with reduced capacity. NB Power will need to continue to monitor this and plan the future of the station accordingly. In the 2030s, it will be important for NB Power to conduct the appropriate assessments to confirm the path forward for existing generating facilities such as Bayside, Belledune and Coleson Cove.

Carbon

The conversion of Belledune to biomass will result in significant greenhouse gas reductions, driving annual CO₂e emissions to less than 1.5 Mt by 2030/31. In 2040/41 and beyond, the retirement of Coleson Cove brings another step change reduction to emissions. In scenario A (high load growth / net-zero 2050), significant progress is made toward achieving a net-zero electricity system. With emissions less than 1 Mt in the 2040s. In Scenario C (low load growth / net-zero 2050), a net-zero electricity system is achieved in the 2040s under existing laws and regulations surrounding greenhouse gas emissions. Scenarios B and D both achieve net-zero in 2035, but it comes at an additional cost to NB Power customers of \$0.6-1.2 B (nominal) over the planning horizon. This analysis is specific to the cost of service associated with the electricity system and does not reflect the broader economic and social cost of climate change.

Operational Characteristics

The electricity system is changing, and the future grid will come with new challenges. The role of emitting resources is changing from base-loaded facilities (e.g. Belledune and Bayside) to quick-start, peaking facilities (e.g. RIGS and Millbank). These types of resources will help integrate renewables and maintain reliability through winter peaking periods.

Solar and wind become much larger sources of energy with many scenarios adding thousands of megawatts of new renewable capacity. This will create changes to operational considerations with significant need for curtailment in low load periods.

Financial

The Partial Revenue Requirement (i.e. the electricity sales revenue to be collected from in-province customers) grows over time across all scenarios, driven by inflationary pressures, pace of decarbonization and a need for increased investment to replace aging infrastructure.

On average, costs per unit of energy are expected to increase by 22 per cent from 2026/27 to 2030/31. This near-term impact is due to increasing impact of existing laws and regulations surrounding greenhouse gas emissions, inflation and the implementation of a strategy to make meaningful progress toward increasing NB Power's equity position.

Capital investment over the 20-year planning horizon exceeds \$40 billion in Scenarios A and B and over \$30 billion in Scenarios C and D. NB Power will need to invest considerably in its existing assets, but there will also be opportunities to partner with third parties to bring private investment into the province. NB Power will need to determine the appropriate balance of risk, capital spending among other factors when making its future investment decisions.

The Future of Nuclear

The existing Point Lepreau Nuclear Generating Station provides tremendous value to New Brunswick's electricity system. Life extensions of similar facilities have been successful and extending the life of the Station would bring about \$900 million in value to the electricity system annually. The costs of extension are currently estimated at closer to \$600 million annually. A decision to extend the life at PLNGS would require an application and approval with the Canadian Nuclear Safety Commission (CNSC). The timeframe under which an extension would typically be pursued is in the range of 5-10 years before end of life.

New nuclear also brings opportunity. Growing New Brunswick's nuclear footprint could bring economies of scale and enable opportunities for regional partnerships. There is still technical, economic and policy considerations to understand before NB Power to invest and commit New Brunswick to new nuclear generation.

Strategic decisions surrounding life extension, a refurbishment and a new build are required to be made with initial support from organizations established within the next five-year period; translating to required business case development within the next three-year period.

New Transmission

New transmission infrastructure between New Brunswick and neighbouring jurisdictions could create opportunities to purchase more energy as well as increase export sales. No specific transmission project design or engineering has been completed for this opportunity. However, the cost is likely in the range of multiple billions of dollars. Further consideration for additional value streams or other sources of funding for transmission infrastructure as well as more specific project cost estimates would be needed to refine this potential opportunity.

Existing Laws and Regulations Surrounding Greenhouse Gas Emissions

Existing laws and regulations surrounding greenhouse gas emissions lead to reductions in CO₂e emissions and higher costs. The phase-out of coal at Belledune drives the majority of both in the early term. By the 2040s, after the assumed end of life for Belledune and Coleson Cove, emissions reduce without any policy signal, achieving the net-zero emission reduction target in the low load scenario. Overall, the existing laws and regulations surrounding greenhouse gas emissions will result in reducing emissions by 34-29 Mt over the 20-year planning horizon at a cost of \$104-110/tonne of CO₂e reduced. These results show that existing laws and regulations are effective in reducing emissions at a cost, and put New Brunswick on a trajectory to achieve net-zero by 2050.

Final Word

NB Power is committed to its customers and meeting their electricity needs in a safe, reliable way. Customers want NB Power to prioritize lowest rates, and NB Power's focus on operational excellence will improve our ability to deliver cost-effective reliable service for our customers. As we consider the cost pressures and trade-offs surrounding load growth and the speed of decarbonization in the 2026 IRP, we maintain our focus on achieving operational excellence while exploring many potential pathways, evaluating opportunities and incorporating no-regret activities along the way.

In such times of uncertainty, it is critical now more than ever that NB Power has an adaptable integrated resource plan to set its foundation to respond to any changes in laws, regulations, or market conditions that may affect the future of electricity in New Brunswick. This IRP is the foundational groundwork on which NB Power will weigh critical decision points that may arise.

Appendix A – Changes from Last IRP

As the integrated resource plan is updated every three years, changes are expected as the industry evolves. Below is a summary of significant changes when comparing the 2026 and 2023 integrated resource plan.

Engagement

- The number of engagements in the 2026 IRP increased by 61 per cent with 6,308 engagements in 2023 compared to 10,157 in 2026.
- Engagement for the 2026 IRP occurred during the spring of 2025 compared to the summer of 2022 for the 2023 IRP. This provided more opportunities to engage customers at community events such as home shows across the province.

Scenario Analysis

- The 2026 IRP base scenarios focus on the pace of decarbonization and pace of load growth as the two main drivers to study. The 2023 IRP base scenarios looked at the pace of technology development and pace of electrification as the two main drivers.
- The 2026 IRP base scenarios explore changes to the pace of decarbonization whereas the 2023 IRP focused on changes to market price and cost of technology.
 - In the 2023 IRP, the scenarios that changed the pace of technology still adopted the same solutions to meet growing demand.
- For the sensitivity scenarios, the 2026 IRP explores no nuclear, additional new nuclear, increased interconnection capacity, as well as no carbon restrictions. The sensitivity scenarios for the 2023 IRP explored the retirement of Mactaquac, no SMRs, as well as the Atlantic Loop project.

Greenhouse Gas Laws and Regulations

- The 2026 IRP assesses the clear impacts associated with the CER which became effective January 1, 2025. The 2023 IRP made assumptions on the impact of the CER as the regulation was under development.
- The 2026 IRP modifies the pace of decarbonization to explore different timelines to achieving net-zero. The net-zero 2035 scenarios include a carbon price of \$340 per tonne in 2035 and beyond with CER restrictions whereas the net-zero 2050 scenarios consider the current OBPS carbon price of \$170 per tonne in 2035 and beyond with CER restrictions.
- The 2023 IRP did not vary the pace of decarbonization with current OBPS carbon price of \$170 per tonne in 2035 and beyond with assumptions for CER restrictions to achieve net-zero in 2035 across all scenarios.

Load forecast

See table below for differences in load forecasts for the 2023 and 2026 IRP.

Table A.1: Changes to Load Forecast from 2023 IRP to 2026 IRP

Parameter	2023 IRP		2026 IRP	
	High Electrification	Low Electrification	High Load Growth	Low Load Growth
EVs	Estimated projections based on Federal and Provincial targets	Load Forecast 2023-2033	2025 Potential Study - Enhanced	Load Forecast 2026-2036 from 2025 Potential Study - Base
Industrial	1000 MW to represent potential of emerging industries or firm export sales	Load Forecast 2023-2033	800 MW to represent potential of emerging industries or firm export sales	Load Forecast 2026-2036
Distributed Generation / BTM Solar	Load Forecast 2023-2033	Load Forecast 2023-2033	Load Forecast 2026-2036 from 2025 Potential Study - Base	2025 Potential Study - Enhanced
Energy Efficiency	Load Forecast 2023-2033	Load Forecast 2023-2033	Load Forecast 2026-2036	2025 Potential Study - Enhanced

Existing Resources

- The 2026 IRP assumes Belledune will convert to biomass in 2030 with a plant capacity of 410 MW. The 2023 IRP base scenarios allowed the model to select the best option for Belledune with a capacity of 375 MW.
- Between the 2023 and 2026 IRP additional development around demand response programs has been completed by NB Power. In the 2023 IRP there was only one tranche of demand response providing an effective capacity of 90 MW. For the 2026 IRP, DR programs were expanded with 80 MW of current volumes plus two additional tranches of DR. Additionally, studies around the effective capacity of DR were completed to establish the ELCC for DR programs.

- The 2026 IRP base scenarios include 702 MW of wind being installed by 2028/29 based on the request for expression of interest. The 2023 IRP base scenarios did not include new wind being added to the system.
- The 2026 IRP base scenarios include the addition of 500 MW of new combustion turbines, with 400 MW designated for New Brunswick and 100 MW for exports installed by 2028/29. The 2023 IRP base scenarios did not include new combustion turbines.
- The 2026 IRP base scenarios include the addition of 117 MW installed (67 MW net) of large industrial biomass generation starting in 2028/29. The 2023 IRP base scenarios did not include addition of large industrial biomass.

Supply Side Resources

- The 2026 IRP provided an option to extend Bayside as a simple cycle or a combined cycle combustion cycle in 2038/39 when the plant is scheduled to retire. The 2023 IRP provided an option to only extend Bayside as a simple cycle combustion cycle in 2038/39 when the plant is scheduled to retire.
- The 2026 IRP base scenarios do not include SMRs. The 2023 IRP base scenarios assumed a minimum of 450 MW of SMRs installed for the low electrification scenarios and up to 750 MW of installed SMRs for the high electrification scenarios.
- The 2026 IRP assumes new nuclear generation that is technology agnostic could be available by 2039/40. The 2023 IRP assumed first-of-its-kind SMR technology could be available as early as 2029/30 for the rapid pace of technology and by 2034/35 for the moderate pace of technology.
- The 2026 IRP assumes two tranches of demand response are available in alignment with NB Power's Strategic Plan. The first tranche available is 146 MW and the second tranche available is 212 MW by 2030/31. The 2023 IRP assumed 90 MW of demand response was available by 2030/31.
- The 2026 IRP includes estimated transmission reinforcement costs for supply side resources when calculating LCOE and LCOC. The 2023 IRP did not include specific transmission reinforcement costs for supply side resources when calculating LCOE and LCOC.

Appendix B – Key Assumptions

Category	2026 Integrated Resource Plan Assumption
Belledune	• Coal phased out by 2030 • Switch to biomass fuel after conversion outage in 2029 • Retirement in 2040/41
Mactaquac	• Mactaquac Life Achievement Project starts 2028 with generator outages starting in 2030 and ending in 2038 • Plant derated throughout the refurbishment project with the potential for up to three units to be unavailable. • Retirement in 2068
Nuclear	• Point Lepreau Nuclear Generating Station life extension beyond 2045/46 in all base scenarios.
Greenhouse Gas Regulation	• 40 per cent of in-province sales from renewable resources • NB OBPS carbon pricing of \$110/tonne in 2026 to \$170/tonne in 2030 and beyond, aligns with latest Environment Canada models • CER effective January 1, 2035, permits limited fossil fuel generation with pooling of emissions. • Net-zero defined as emissions of 95 per cent from 2005 levels, 0.44 Mt CO₂e • Net-zero 2050 cases assume current NB OBPS pricing structure • Net-zero 2035 cases assume carbon pricing escalates to \$340/tonne starting in 2035.

Category	2026 Integrated Resource Plan Assumption
Economic Assumptions	• Long term CPI of two per cent based on Conference Board of Canada Quarterly Rates Data/Forecast Published June 2025 • Long term foreign exchange rate taken from Conference Board of Canada for fiscal years 2026/27 through to 2035/36 • Long term foreign exchange rate of 1.36 per cent for fiscal years beyond 2035/36 taken from Conference Board of Canada Quarterly Rates Data/Forecast Published June 2025 • Credit rating assumptions retrieved from Bloomberg December 2025 • Long term debt financing rate of 5.25 per cent based on an analysis of public financing rates (3.5 per cent long term bond rate, 110 basis point spread, and guarantee fee of 0.65 per cent). • Return on equity for public owned projects assumed to be 9 per cent at a 60/40 deemed debt/equity ratio. • Weighted average cost of capital of 6.75 per cent based on the long-term capital structure target, long term debt financing rate and return on equity assumptions. • Construction cost escalation based on third party generation alternative supply study and varies by type
Fuel and Electricity Market Price Forecast	• Short-term fuel and electricity market prices based on the 2026/27 NB Power budget • Long-term fuel and electricity market prices provided by Energy Ventures Analysis Inc.
In Province Load Forecast	• In province load forecast based on the NB Power Load Forecast 2026-2036 completed in 2025 including results of Electrification Potential Study completed in 2025 by Dunskey • Low load growth scenarios include base load forecasts plus enhanced energy efficiency savings and distributed generation • High load growth scenarios include base load forecasts plus enhanced EV adoption forecast and gradual addition of 800 MW industrial load between 2028/29 and 2045/46

Category	2026 Integrated Resource Plan Assumption
Export Load	- Existing export contracts persist throughout the study period - Opportunity exports not included in generation capacity expansion modelling decisions - Opportunity exports to electricity markets assumed available but adjusted for renewable impacts on regional market prices and correlations - Export sales market prices inversely correlated with volume of available wind.
Capacity and Transmission Planning	- Minimum of 20 per cent planning reserve margin based on 2025 Maritimes Comprehensive Review of Resource Adequacy published by the Northeast Power Coordinating Council - Import and export limits based on New Brunswick TPL-001 transmission planning study results
Generation Resources	- Existing generating stations operate until their planned retirement dates. Hydro generating stations are assumed to be refurbished or replaced in-kind upon retirement 500 MW of combustion turbines available in 2028, with 400 MW of capacity for New Brunswick and 100 MW of capacity exports throughout the study period - Renewable PPAs are assumed to be extended at market value
Supply Side Resources	- Candidate generation and costs provided by Energy and Environmental Economics and NB Power data - Screening analysis based on emission profiles, dispatch characteristics and cost effectiveness
Capacity Contribution	Effective load carrying capability provided by Energy and Environmental Economics and NB Power data
Demand Response	- Existing installed capacity of 80 MW available throughout the duration of the study period - Option to add new installed capacity in two tranches, the first tranche is 146 MW and the second is 212 MW by 2030/31 based on results of Dunskey Potential Study

Category	2026 Integrated Resource Plan Assumption
Energy Efficiency	- Legislated energy efficiency targets of 0.65 per cent in 2026/27, 0.70 per cent in 2027/28 and 0.75 per cent in 2028/29 and each year after - High load growth scenarios assume efficiency programs achieve legislated targets - Low load growth scenarios assume energy efficiency programs exceed legislated targets based on results of 2025 potential study
Transmission	- In province transmission costs are included for new technologies such as wind, solar, storage, combustion turbines and nuclear - Transmission reinforcement including new build costs and investments integrated into expansion planning decisions - Transmission cost estimates included in financial projections - No additional import or export capability included in base scenarios
Sensitivity Analysis for New Nuclear	- Build 750 MW of new nuclear in 2039/40 - Build additional 750 MW of new nuclear in 2044/45. Either refurbish Point Lepreau Nuclear Generating Station or build second new unit - Add energy and capacity sale of 500 MW starting in 2044/45
Sensitivity Analysis for No Nuclear	No nuclear after retirement of Point Lepreau Nuclear Generating Station in 2041/42
Sensitivity Analysis for Increased Interconnections	- Additional 1,000 MW of increased interconnection capability starting in 2035/36 with neighboring jurisdictions - Not specific to an interface, no specific energy or capacity sale created
Sensitivity Analysis for No Carbon Restrictions	- Remove emission constraints from OBPS carbon pricing - Remove emission constraints from CER restrictions - Remove coal phase out, Belledune continues to operate on coal until end of life in 2040/41 - Maintain renewable portfolio standard of 40 percent for in province sales

Appendix C - Policy Considerations

Since the release of the 2023 Integrated Resource Plan, public policy has continued to develop as the electricity sector moves toward reducing carbon emissions. NB Power recognizes that as governments actively pursue climate targets, public policy is a major factor influencing the pace at which decarbonization occurs. As a result, NB Power selected the pace of decarbonization as a key axis for analysis to understand how public policy will affect the long-term reduction of emissions within the electricity sector.

Public policy at the provincial, national and international levels has shaped the 2026 IRP. It sets the context for the IRP, highlighting the importance of policy decision in guiding the transition to a lower-carbon electricity system.

Provincial Laws, Regulation and Policy

As a Crown corporation, NB Power adheres to the laws, regulations and policies set out by the provincial government. The government also provides strategic direction to which NB Power aligns.

Electricity Act

The New Brunswick *Electricity Act* is the legislation that establishes the framework for how electricity is regulated in the province and outlines how the electricity system is managed in the province.

NB Power's Integrated Resource Plan is impacted by several provisions and requirements in the *Electricity Act*. Section 100 of the *Electricity Act* establishes the requirement for an Integrated Resource Plan. It lists several elements that must be included in the Integrated Resource Plan and sets out required timelines for submission to and approval by the Executive Council of the Government of New Brunswick.

Subsection 100(2) requires the Integrated Resource Plan to be developed by the Corporation in accordance with the principles of least-cost service, economic and environmental sustainability and risk management.

The *Electricity Act* also enables Regulation that prescribes requirements for NB Power with respect to energy efficiency, renewable energy resources and reliability.

Energy Efficiency

NB Power is required by regulation to develop and administer demand side management and efficiency programs. The regulation includes minimum energy efficiency targets to reduce in province electricity sales by

1. 0.65 per cent for fiscal year 2026/2027
2. 0.70 per cent for fiscal year 2027/2028
3. 0.75 per cent each year thereafter⁴⁶

NB Power has significantly expanded its energy efficiency program offerings in recent years and will continue to do so. Efforts to reduce and shift customer electricity consumption will lessen reliance on fossil-fueled plants and increase the supply of New Brunswick's electricity needs from renewables.

Renewable Portfolio Standard

NB Power is required by regulation to develop renewable energy resources in the province with First Nations involvement to ensure in-province electricity sales are supplied with a minimum target of 40 per cent from renewable resources.⁴⁷

NB Power acknowledges the importance of integrating renewable resources into the system. With First Nations involvement, NB Power plans to more than double the installed wind generation in the next few years to keep rates low and stable, improve energy security and reduce greenhouse gas emissions.

⁴⁶ Government of New Brunswick, *Energy Efficiency Regulation – Electricity Act*, NB Reg 2022-74 (under the *Electricity Act*, SNB 2013, c.7). Retrieved from <https://laws.gnb.ca/en/document/cr/2022-74/>

⁴⁷ Government of New Brunswick, *Electricity from Renewable Resources Regulation – Electricity Act*, NB Reg 2015-60 (under the *Electricity Act*, SNB 2013, c.7). Retrieved from <https://laws.gnb.ca/en/document/cr/2015-60/>

Reliability Standards

NB Power is required by regulation to ensure compliance with the North America Electric Reliability Corporation (NERC) Reliability Standards.⁴⁸ NB Power is also a full member of the Northeast Power Coordinating Council (NPCC) and works diligently to comply with all NERC and NPCC reliability criteria and standards when planning and operating the bulk power system. NB Power incorporates all relevant NERC and NPCC standards and criteria into its resource adequacy planning when developing the integrated resource plan.

Mandate Letter

In accordance with the Accountability and Continuous Improvement Act, the provincial government provides NB Power a Mandate Letter⁴⁹, which communicates the intention and expectation for NB Power's goals and objectives to align with the Government's priorities. Below are the requirements in the 2025 mandate letter that impact the 2026 IRP

- make progress toward a capital structure of at least 20 percent equity through financial planning cost reductions and other appropriate mechanisms that will maintain low and stable rates
- reduce expenditures as affordability remains a major concern for New Brunswickers
- provide key inputs and assumptions for future revenue requirements
- increase energy efficiency savings and increase support for home energy retrofits including free heat pumps and solar retrofits

Climate Change Act

The Government of New Brunswick recognizes the importance of climate change and the province's role in supporting Canada's commitment to reducing greenhouse gas emissions. The *Climate Change Act* is a key piece of legislation that provides the framework for how emissions are managed in New Brunswick. The key assumptions for carbon policy in the IRP stem from the requirements established in the *Climate Change Act* and aligned with any federal plans to reduce greenhouse gas emissions and achieve net-zero targets.

⁴⁸ Government of New Brunswick, *Reliability Standards Regulation – Electricity Act*, NB Reg 2013-66 (under the *Electricity Act*, SNB 2013, c.7). Retrieved from <https://laws.gnb.ca/en/document/cr/2013-66/>

⁴⁹ NB Power, *Mandate Letter*, Retrieved from <https://www.nbpower.com/en/about-us/accountability-reports/mandate-letter>

The *Climate Change Act* also enables the New Brunswick Output Based Pricing System (NB OBPS). The NB OBPS is a performance-based carbon pricing system derived from the federal backstop program that is applicable to large industrial facilities operating in the province of New Brunswick. Large industrial facilities that emit an excess of 50,000 of equivalent CO₂e are required to pay a price per tonne of carbon dioxide equivalent of greenhouse gas emissions.

Performance standards⁵⁰ vary by fuel type and tighten over time. NB Power will be subject to carbon taxes on emissions that exceed the performance standards set out in the NB OBPS⁵¹. It is anticipated that the OBPS intensity standards will continue through the IRP analysis period.

NB Power's Belledune, Coleson Cove and Bayside generating stations are subject to the NB OBPS. NB Power also owns and operates Millbank, Ste-Rose and Grand Manan fossil fuel generating stations, which fall below the emission threshold and do not participate in the NB OBPS program.

As shown in Figure 1, carbon pricing under the NB OBPS is \$110 per tonne for the 2026 compliance period. It is regulated to increase by \$15 per tonne each year until it reaches \$170 per tonne in 2030^{52,53}.

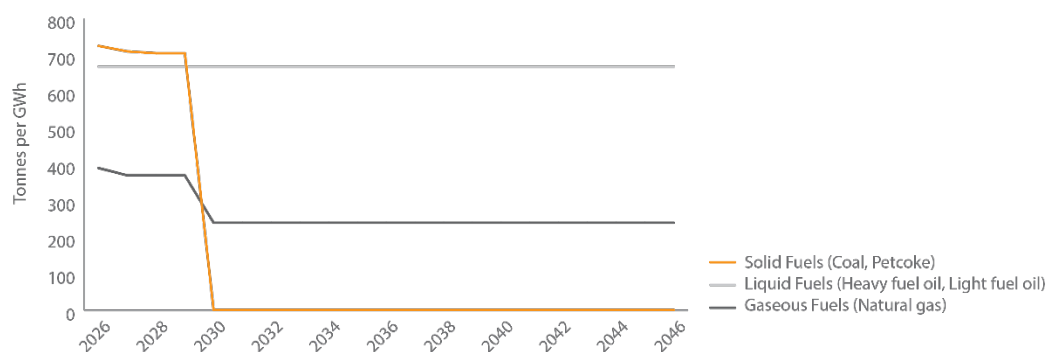
⁵⁰ The Output-Based Pricing System uses a performance standard in the form of average emissions per unit of electric output. The utility would pay only on the emissions above this emission intensity standard. For example, if the performance standard were 370 tonnes per gigawatt-hour and a station's actual emission intensity were 470 tonnes per gigawatt-hour, the portion above 370 tonnes per gigawatt-hour, or 100 tonnes per gigawatt-hour, would be subject to the carbon price.

⁵¹ Government of New Brunswick, New Brunswick Regulation 2022-83 under the Climate Change Act (O.C. 2022-316), NB Reg 2022-83. Retrieved from <https://www2.gnb.ca/content/dam/gnb/Departments/ag-pg/PDF/RegulationsReglements/2022/2022-83.pdf>

⁵² Government of Canada, Greenhouse Gas Pollution Pricing Act, SC 2018, c. 12. Retrieved from <https://laws-lois.justice.gc.ca/eng/acts/g-11.55/FullText.html>

⁵³ In May 2026 the Federal Government announced a change to the carbon price under the federal industrial carbon pricing regime. This change has not been included in the 2026 IRP which continues to rely on the NB OBPS and current provincial carbon pricing regime. An analysis was completed that shows no significant change to the base scenario expansion plans, costs or emission projections. <https://www.canada.ca/en/services/environment/weather/climatechange/climate-action/pricing-carbon-pollution.html>

Figure C.1: NB OBPS Emission Intensity Standards



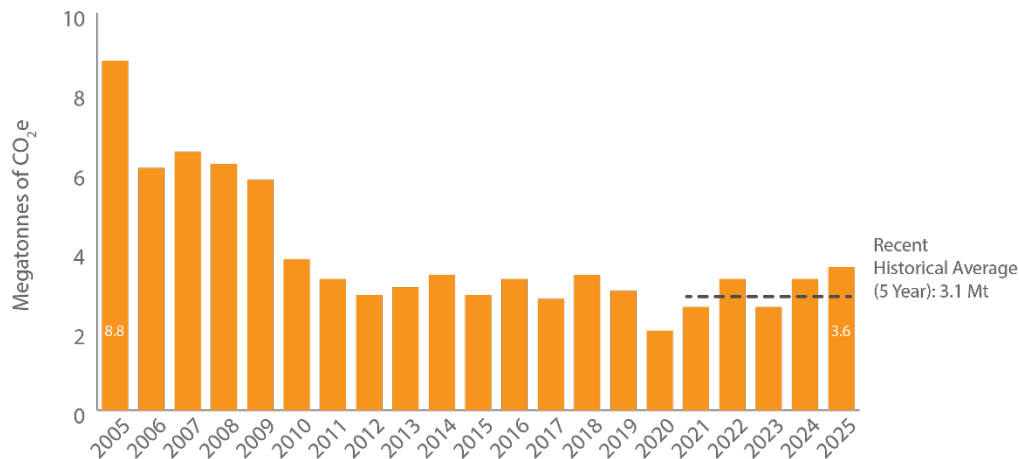
To translate vision into action to achieve net-zero goals, the Government of New Brunswick produced a Climate Change Action Plan (2022-2027)⁵⁴ and a provincial energy strategy in 2023⁵⁵. These plans contemplated achieving the goals of the federal clean electricity regulation to make progress toward a clean energy grid with a commitment for New Brunswick to achieve a net-zero economy by 2050. NB Power’s objectives are aligned with these plans and we monitor and report our emissions accordingly.

Climate change actions continue to affect the pace of decarbonization at NB Power and are considered in the scenarios examined in the IRP. As shown in Figure C.2, NB Power continues to contribute to achieving the province’s greenhouse gas reductions, having reduced our emissions by approximately 65 percent from 2005 to today. We have incorporated existing laws and regulations surrounding greenhouse gas emissions into the IRP and set our sights on our contribution to the province’s next greenhouse gas reduction milestone in 2030.

⁵⁴ Province of New Brunswick, *Our Pathway Towards Decarbonization and Climate Resilience: New Brunswick’s Climate Change Action Plan 2022–2027*, *Climate Change Action Plan*, <https://www2.gnb.ca/content/dam/gnb/Corporate/Promo/climate/climate-change-action-plan.pdf>

⁵⁵ Province of New Brunswick, *Powering Our Economy and the World with Clean Energy: Our Path Forward to 2035*, *Clean Energy Strategy*, <https://www2.gnb.ca/content/dam/gnb/Corporate/Promo/energy-energie/GNB-CleanEnergy.pdf>

Figure C.2: NB Power's Historical Greenhouse Gas Emissions 2005-2025^{56,57}



Federal Laws, Regulation and Policy

In 2015, Canada was one of 195 countries to sign the Paris Agreement and commit to collectively reduce global emissions⁵⁸. In March 2016, Canada's First Ministers released the Vancouver Declaration on Clean Growth and Climate Change⁵⁹, which included a nationwide targeted reduction of emissions to 30 per cent below 2005 levels by 2030. In 2021, Canada further increased this targeted reduction to 40 to 45 per cent below 2005 levels by 2030, as legislated in the *Canada Net-Zero Emissions Accountability Act*⁶⁰. This legislation also sets a target to achieve economy-wide net-zero by 2050.

⁵⁶ Emissions for 2025 are an unverified estimate.

⁵⁷ Emission data based on internal data for NB Power owned facilities.

⁵⁸ Government of Canada, Paris Agreement, January 6, 2016. Retrieved from <https://www.canada.ca/en/environment-climate-change/services/climate-change/paris-agreement>

⁵⁹ Canadian Intergovernmental Conference Secretariat, Vancouver Declaration on Clean Growth and Climate Change, March 3, 2016. Retrieved from <https://scics.ca/en/product-produit/vancouver-declaration-on-clean-growth-and-climate-change/>

⁶⁰ Government of Canada, Canada Net-Zero Emissions Accountability Act, SC 2021, c. 22. Retrieved from <https://laws-lois.justice.gc.ca/eng/acts/c-19.3/fulltext.html>

More recently, the federal government has published several legislative and regulatory requirements including the Canada Emission Reduction Plan⁶¹ that outlines targets, objectives and actions to achieving net-zero emissions across all sectors in Canada. The federal government has enacted laws and regulations indicating that

1. coal fired generation shall be phased out by 2030⁶²
2. natural gas generation shall meet a performance-based standard with prescriptive emission intensity limits⁶³
3. each province shall implement a carbon accounting system that aligns with the federal carbon output-based pricing system

NB Power has incorporated these requirements in its development of the 2026 IRP.

Clean Electricity Regulation

Effective December 2024, the Clean Electricity Regulation (CER) is a critical piece of federal legislation that enables significant greenhouse gas reductions in the electricity sector to place Canada on a path to net-zero by 2050.⁶⁴ From 2050 onward, the entire economy will need to become truly net-zero, with all emissions eliminated or offset through other emission reduction or carbon removal measures. Crucially, while this legislation does limit emissions it does not eliminate emissions from 2035 to 2049 and allows for low operating hour emitting generation such as combustion turbines to be operated to ensure reliability within the electricity grid.

⁶¹ Government of Canada, 2030 Emissions Reduction Plan, Retrieved from <https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan.html>

⁶² Government of Canada, Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations, SOR/2012-167 (under the Canadian Environmental Protection Act, 1999). Retrieved from <https://laws-lois.justice.gc.ca/eng/regulations/sor-2012-167/page-1.html>

⁶³ Government of Canada, Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity, SOR/2018-261. Retrieved from <https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-261/FullText.html>

⁶⁴ Government of Canada, Clean Electricity Regulations, SOR/2024-263. Retrieved from <https://laws-lois.justice.gc.ca/eng/regulations/SOR-2024-263/FullText.html>

The regulation is applicable to all fossil fuel generators subject to the NERC reliability standards. The CER does permit the operation of fossil fuel generators from 2035 to 2050. As a result, NB Power can operate existing facilities such as Coleson Cove, Millbank and Ste Rose generating stations until their assumed end of life. In the case of the Bayside Generating Station as well as the proposed new 500 MW combustion turbine plant, the regulation will come into effect toward the end of 2050. Exclusions from the CER include Belledune based on the planned conversion to biomass as well as Grand Manan due to its size.

The regulation provides enough flexibility to use fossil fuel generators for capacity when required to maintain system reliability while integrating renewable and non-greenhouse gas-emitting sources into the system. The CER supports limited fossil fuel generation provided the generators meet a performance-based intensity standard. This means that regulated units will be limited on an annual basis to 569.4 tonnes of CO₂e per installed megawatt from 2035 to 2049⁶⁵. Flexibility within the CER also includes banking and pooling of annual emissions across the generating fleet. Provisions for emergency operations to maintain system reliability are permitted. The regulation also supports carbon capture technology and excludes small and remote units.

It is critical that NB Power be permitted to retain and operate some fossil fuel generation during the transition period as it balances the integration of renewable resources, maintaining system reliability and keeping rates low for customers.

⁶⁵ The Clean Electricity Regulation states that all emissions from the electricity sector are required to meet an emission intensity limit of 65 tonnes of carbon dioxide equivalent per gigawatt hour of electricity that could theoretically be generated. This is mathematically equivalent to $65 \text{ t/GWh} \times 8760 \text{ h} = 569.4 \text{ t/MW}$. For example, Coleson Cove has an installed capacity of 972 MW. It would have an emission limit of $972 \times 569.4 = 533,457$ tonnes per year.

Appendix D - Economic Assumptions

To develop an IRP that keeps rates cost-effective and stable, NB Power performed various economic analyses to determine the financial impact of potential supply-side resources, such as a large generator, and demand-side options, such as customer-driven actions. To create the IRP analyses, NB Power used the following financial parameters

- consumer price index
- foreign exchange rate
- weighted average cost of capital

Consumer Price Index

The IRP was developed using the consumer price index (CPI) to adjust operations, maintenance and administration (OM&A) and regular capital expenditures in future years. Since publishing the 2023 IRP, New Brunswick CPI (all items) has increased 7.63 per cent or 2.48 per cent each year. Inflation has since slowed in past few years. However, price risk remains given current market conditions such as supply chain pressures and tariff uncertainty. NB Power currently forecasts CPI to be 2.00 per cent in the long-term, which aligns with the Bank of Canada's nationwide target⁶⁶.

Foreign Exchange Rate

The IRP uses the 10-year foreign exchange rate forecast published by the Conference Board of Canada for fiscal years 2026/27 through to 2035/36. The 10-year foreign exchange rate forecast ranges between 1.34 and 1.36 US dollars to Canadian dollars for fiscal years 2026/27 through to 2035/36.

For fiscal year 2035/36 and beyond, the IRP uses the long-term foreign exchange rate of 1.36 US dollars to Canadian dollars. This is a six-year historical average exchange rate published by the Conference Board of Canada.

⁶⁶ Conference Board of Canada Quarterly Rates Data/Forecast Published June 2025.

Cost of Capital

As a cost-of-service utility, NB Power sets electricity rates to recover its prudent costs, including a return on capital sufficient to cover debt costs and provide a reasonable return on equity. The *Electricity Act* does not prescribe a specific methodology for determining net earnings (return on equity) in NB Power's revenue requirement. However, NB Power is mandated to make meaningful progress toward reducing the debt weighting in its capital structure, and earning a return on equity that is consistent with its debt-reduction targets is necessary to achieve this objective.

Across Canada, many regulated electric utilities determine revenue requirements using a return on rate base framework, applying a deemed capital structure and an allowed return on equity. This approach is consistent with the manner in which the revenue requirement under the Open Access Transmission Tariff (OATT) is determined, where an approved return on equity of 10 per cent is applied.

Return on Rate Base Methodology

The electric utility industry is highly capital intensive and relies on significant borrowing to fund long-lived infrastructure investments. To provide a fair and reasonable opportunity to earn a return, regulators commonly approve a deemed capital structure with an associated return on equity for purposes of setting the cost-of-capital component of the revenue requirement. In Canada, many utilities are authorized to earn a deemed return on equity of approximately nine per cent, typically based on a capital structure of approximately 60 per cent debt and 40 per cent equity.

Where a utility's actual debt weighting exceeds 60 per cent, the use of a deemed capital structure allows the utility to make progress toward a healthier balance sheet over time, while still earning a return that reflects the risks associated with owning, operating and maintaining large-scale capital assets. This approach also supports more predictable rates, as the allowed return is based on the deemed capital structure rather than the utility's actual capital structure in any given period.

In the 2026 IRP, a nine per cent return on equity (ROE) applied to a deemed equity weighting of 40 per cent. The remaining 60 per cent of capital was assumed to earn the weighted average cost of debt, inclusive of a 0.65 per cent debt management fee. New long-term debt issuances were assumed to bear interest rates of 4.65 per cent to 5.25 per cent, inclusive of the management fee. On this basis, the resulting weighted average cost of capital for incremental investment was 6.75 per cent.

Appendix E - Fuel and Electricity Market Price Forecast

NB Power operates a diversified power system that relies on various fuel sources, including coal, heavy fuel oil, light fuel oil, natural gas and uranium. Coal is not included in the forecast as this fuel will be phased out by 2030. Uranium is also not included as it does not have a commodity market.

NB Power is subject to commodity fuel price volatility through power purchase agreements and wholesale market electricity purchases. NB Power economically dispatches its generation to reduce the pricing risks associated with individual commodities. NB Power also deploys a comprehensive hedging strategy designed to mitigate risks arising from short-term fluctuations in fuel and electricity market prices and to facilitate more effective planning for potential impacts on electricity prices.

For the IRP fuel price forecast, NB Power used a combination of forward prices from the 2026/27 NB Power budget and long-term forecasts developed by its fuel price forecasting consultant, which were updated in June 2025.

Figure 1 and Figure 2 show select data from the resulting fuel price forecast. The cost of transportation or other fuel-related costs and fees that would be applicable to NB Power, such as carbon taxes, are included in the modelling assumptions.

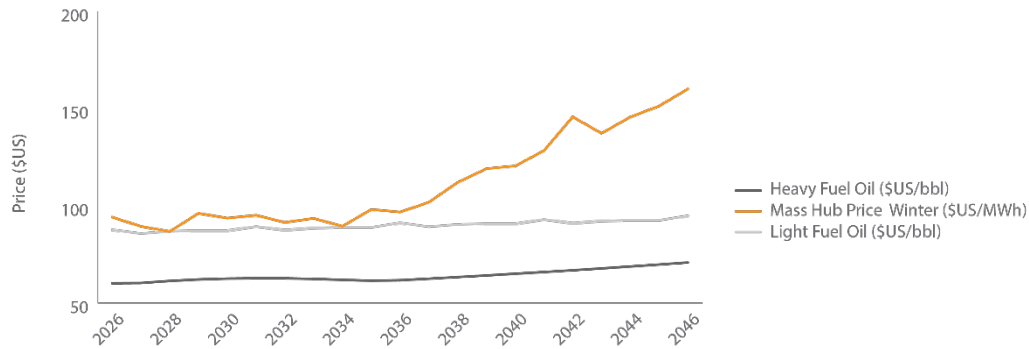
Electricity and Oil Price Forecasts

NB Power uses Massachusetts Hub (Mass Hub) price index for electricity prices. Mass hub is highly correlated with natural gas prices and is a key indicator for any electricity imports or exports representing purchases or sales in the wholesale market.

Heavy fuel oil is the primary fuel used by the Coleson Cove Generating Station.

Light fuel oil is assumed to be the backup fuel for dual-fuel combustion turbine generators.

Figure E.1: Electricity⁶⁷, Light and Heavy Fuel Oil⁶⁸ Price Forecasts



Natural Gas Price Forecasts

Natural gas is used by the Bayside generating station and will be used by the proposed new 500 MW combustion turbine plant. Natural gas pricing assumptions used in the IRP depend on the operating characteristics of the generation supply option.

NB Power has secured a long-term supply source and the required pipeline reservations to bring competitively-priced natural gas from AECO Hub in Western Canada to New Brunswick.

During the coldest periods, incremental natural gas purchases can prove to be challenging due to either pipeline constraints or extreme market prices. For energy security purposes, natural gas units are assumed to require either a firm gas transmission path or dual fuel capability. The ability to generate from both gaseous and liquid fuels will also keep options open in the future for the integration of renewable fuels such as biodiesel, renewable natural gas and hydrogen.

⁶⁷ Massachusetts Hub (Mass Hub) is an electricity price within the ISO-NE system

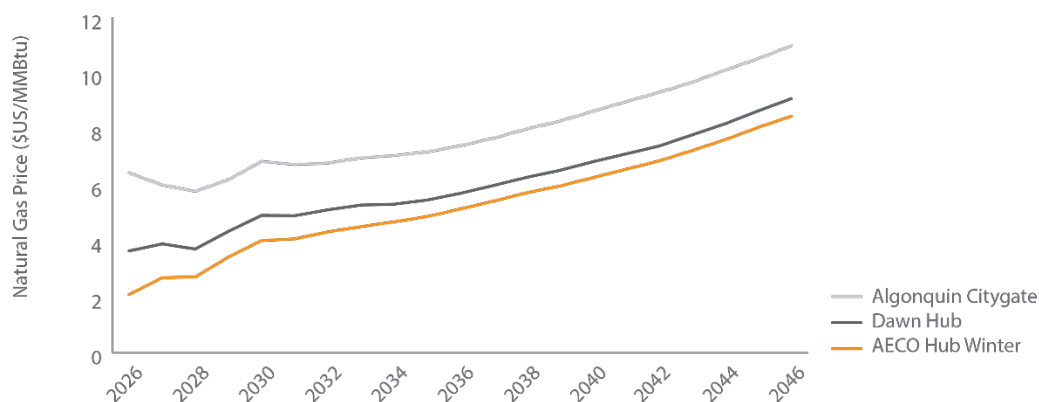
⁶⁸ Light and heavy fuel oil price forecast from external consultant

Combined cycle generators are relatively efficient and operate at higher capacity factors than other less efficient generators and often need a longer-term, stable fuel supply. As a result, the IRP reflects a requirement for firm commitments on fuel volumes and transportation and assumes this will be facilitated through the Dawn Hub natural gas index.

Peaking units operate less often and at irregular periods, therefore NB Power relies on spot market gas purchases using the Algonquin Citygate Hub as a more appropriate natural gas price for the purposes of the IRP.

Peaking units such as the new 500 MW combustion turbine generation plant will also require the ability to be fired from light fuel oil in the case of gas supply issues.

Figure E.2: Natural Gas Price Forecasts for Algonquin Citygate⁶⁹, Dawn Hub⁷⁰ and AECO⁷¹



⁶⁹ Algonquin Citygate is a natural gas trading hub located in Massachusetts.

⁷⁰ The Dawn Hub is a natural gas trading hub located in southwestern Ontario.

⁷¹ AECO Hub is a natural gas trading hub located in southern Alberta.

Table E.1: 20 Year Fuel and Electricity Prices Forecast

	Mass Hub	HFO	AGT Gas	AECO Gas	Dawn Hub	Light Fuel Oil
Fiscal Year	(\$USD/MWh)	(\$USD/BBL)	(\$USD/MMBtu)	(\$USD/MMBtu)	(\$USD/MMBtu)	(\$USD/BBL)
2026	94.15	60.20	6.43	2.08	3.64	87.58
2027	89.41	60.33	6.00	2.68	3.89	85.76
2028	86.77	61.36	5.77	2.71	3.71	86.82
2029	96.13	62.14	6.19	3.42	4.34	87.18
2030	93.63	62.59	6.84	4.01	4.91	87.18
2031	95.10	62.76	6.73	4.07	4.90	89.33
2032	91.49	62.73	6.78	4.32	5.11	87.48
2033	93.53	62.43	6.97	4.51	5.28	88.56
2034	89.47	61.93	7.05	4.68	5.31	88.92
2035	98.08	61.48	7.18	4.87	5.46	88.92
2036	96.75	61.73	7.40	5.14	5.70	91.11
2037	101.80	62.54	7.67	5.42	5.98	89.23
2038	111.97	63.37	8.00	5.72	6.27	90.33
2039	119.04	64.18	8.28	5.96	6.52	90.70
2040	120.44	65.07	8.63	6.26	6.83	90.70
2041	128.30	65.96	8.98	6.56	7.11	92.94
2042	145.68	66.87	9.31	6.86	7.39	91.01
2043	137.22	67.80	9.67	7.23	7.79	92.14
2044	145.59	68.80	10.11	7.62	8.19	92.52
2045	151.22	69.81	10.52	8.06	8.65	92.52
2046	159.98	70.86	10.98	8.46	9.09	94.79

Appendix F - Load Forecasts

NB Power produces an annual load forecast projecting New Brunswick's future electricity requirements for the purposes of budgeting and planning for the future. The 2026 IRP uses the NB Power Load Forecast 2026-2036 completed in 2025 as the base load forecast. The load growth scenarios are made up of the base load forecast plus enhanced forecasts for energy efficiency savings, behind-the-meter generation, electric vehicle adoption and industrial load growth.

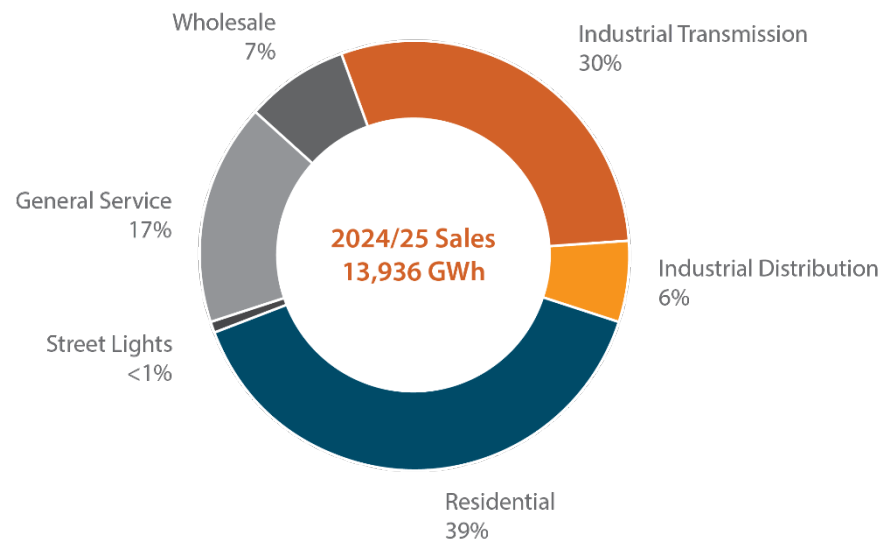
Customer Load Forecasts

The load forecast groups customers into six customer classifications, based on their electricity consumption patterns and types of end-uses, with customers in each group impacted by similar factors such as weather and economic activity. The six customer classifications are

1. residential
2. industrial distribution
3. general service
4. wholesale (which includes sales to customer classifications noted above by municipal utilities in Saint John and Edmundston)
5. industrial transmission
6. street lights

Figure F.1 shows the relative proportions of NB Power's 13,936 GWh of actual energy sales in the 2024/25 fiscal year to each of the six customer classifications.

Figure F.1: 2024/25 Energy Sales by Customer Classification



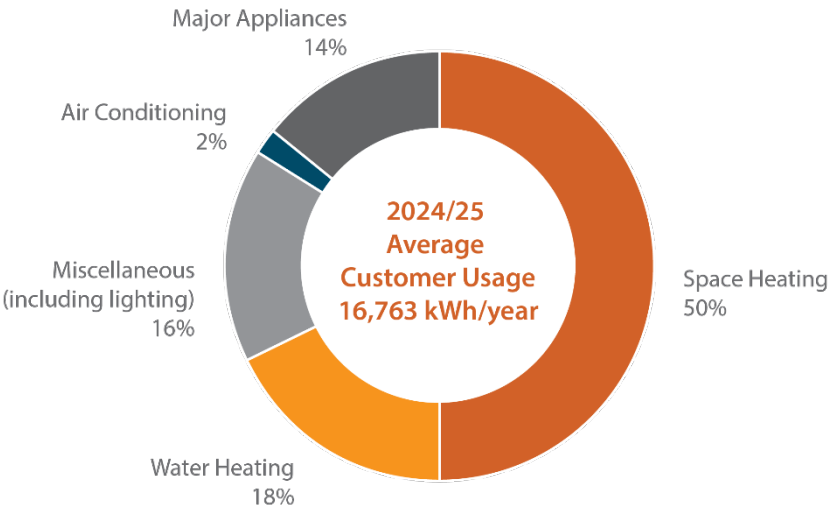
Residential

Typically, New Brunswick households make up over 95 per cent of the residential group.

In the 2024/25 fiscal year, residential customers accounted for 43 per cent of the total in-province electrical energy sales, with 40 per cent of in-province sales being made directly to residential customers and three per cent of in-province electricity sales made to residential customers through wholesale utilities.

Residential electricity consumption is forecast using an end-use model that forecasts the consumption of individual appliance types and aggregates them for the customer class. Average household energy use includes electric space heating, water heating and other uses such as appliances, lighting and cooling. In 2024/25, the average household used an estimated 16,763 kWh/year.

Figure F.2: 2024/25 Approximate Breakdown of Average End-Use Amongst Residential Customers



At the end of 2024/25, there were approximately 383,000 year-round residential customers in New Brunswick served directly or indirectly by NB Power. Of those, 341,000 were direct NB Power customers and 42,000 were municipal utility customers in Saint John and Edmundston.

Residential Growth Forecast

Growth in the residential forecast is driven by the addition of new customers. Growth in the number of customers is driven by population growth, and the societal trend of smaller household size that results in the same population being spread over more homes.

Increasing average customer use is offset by demand-side management programs delivered by NB Power and naturally occurring, energy efficient choices made by customers.

Residential water and space heating in New Brunswick is largely electrified. Over 90 per cent of homes in the province already use electric water heaters. Approximately 80 per cent of homes in New Brunswick already use electricity as their primary heating source, with many more relying on electricity to supplement other heating sources.

As requirements for space-heating in New Brunswick continue to electrify, growth in electricity requirements driven by switching from oil, natural gas or wood to electric space-heating are offset through energy efficiency and the switch from electric baseboard to electric heat pumps across the province.

Heat pumps are more efficient than baseboards, electric furnaces, or similar heating systems, cutting consumption by about half. For every conversion in New Brunswick from a non-electric heating system to a heat pump, there is a conversion from baseboard heating to a heat pump. As a result, there is little to no net change in overall electricity consumption for residential space heating as customers continue to electrify their heating systems. The large volume of conversions to heat pumps is resulting in increases to demand in the summer period to meet cooling needs.

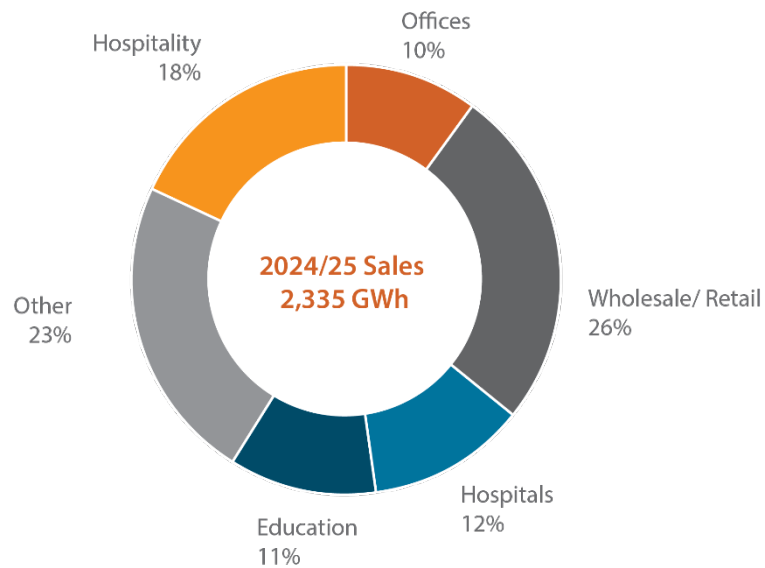
General Service

The general service classification includes commercial customers such as retail, hospitality and business offices as well as institutional customers such as hospitals, schools and universities.

As of March 2025, NB Power directly served approximately 28,500 general service customers while wholesale utilities served approximately 5,200 general service customers, indicating a total of 33,700 general service customers in New Brunswick.

In the 2024/25 fiscal year, general service energy requirements made up 20 per cent of the total in-province energy sales (17 per cent directly by NB Power and three per cent by wholesale utilities). Figure F.3 shows the proportion of NB Power's 2,335 GWh total general service sales by sector in 2024/25.

Figure F.3: General Service Sales



Approximately 30 per cent of general service sales are to the institutional sector. The remaining general service sales in New Brunswick reflect the level of commercial activity and are closely related to employment and the provincial gross domestic product (GDP).

General Service Forecast

Weather affects the amount of electricity required for heating or cooling and the general service forecast uses an econometric model to relate changes in the level of sales to changes in level of employment, the provincial GDP and the number of heating degree days.

Industrial

New Brunswick's industrial customers account for about 36 per cent of the total in-province energy use.

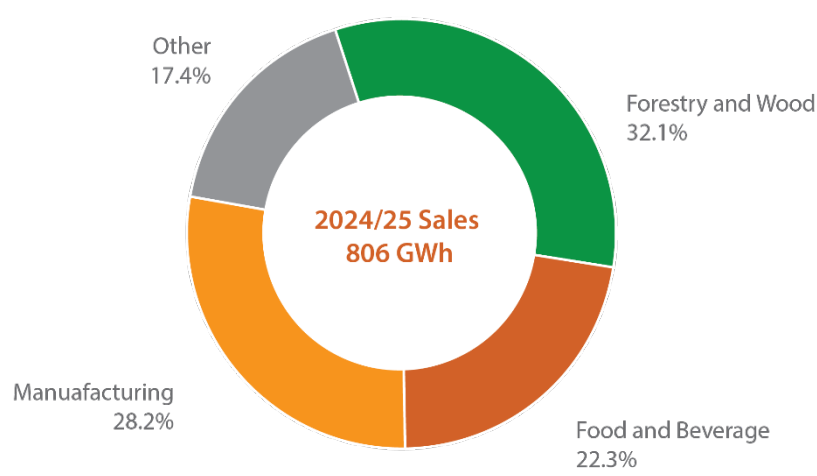
Industrial customers are divided into two groups

- industrial distribution customers (served at transmission voltages less than 69 kV)
- industrial transmission customers (served at transmission voltages of 69 kV and above)

Industrial Distribution

NB Power serves approximately 1,800 industrial customers at distribution voltages (less than 69 kV), while wholesale utilities serve approximately 70 others, totaling 1,870. Together, they account for approximately six per cent of the total provincial electrical energy requirements. Figure F.4 shows the proportions of NB Power’s 806 GWh total industrial distribution sales by sector in 2024/25.

Figure F.4: NB Power Industrial Distribution Sales



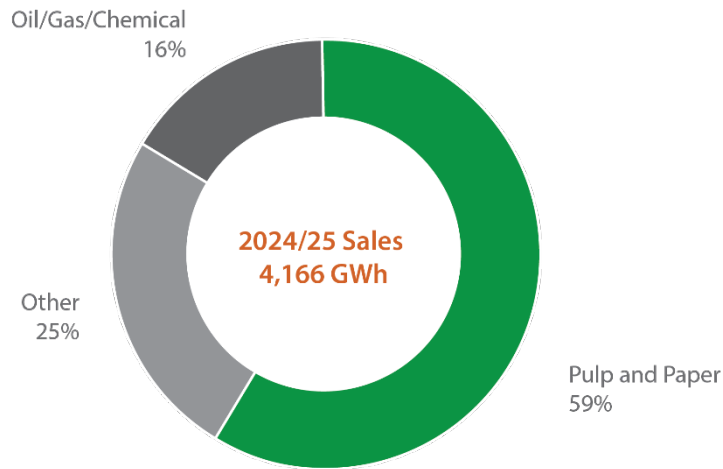
Industrial Distribution Forecast

The industrial distribution forecast uses an econometric model to relate changes in the level of sales to changes in the provincial GDP. Increases in the forecasted GDP growth will result in corresponding increases to industrial load growth.

Industrial Transmission

There are 46 industrial customers served at transmission voltages (69 kV and above). These customers make up most of the industrial sales. Figure F.5 shows the 2024/25 portions of 4,166 GWh total industrial transmission sales to each of the main industry groups.

Figure F.5: Industrial Transmission Sales



Industrial Transmission Forecast

The forecast for these customers is done using a bottom-up methodology where each customers' requirements are forecast individually. Adjustments such as growth for electrification or reductions for energy efficiency are then added to the cumulative total.

Peak Demand

Peak demand is the maximum energy requirement on the system during a one-hour period and is a critical factor to consider when planning for system operations and new supply sources.

As a winter-peaking utility, NB Power commonly experiences the highest peaks in January and February, which are the coldest months the province faces. It is during these coldest months that New Brunswickers rely heavily on their heating systems to help keep their homes and businesses comfortable.

As electric space heating is currently the most common heat source in homes and businesses in the province, heating load is a significant driver for NB Power's peak demand and it is expected to continue. The growth of high efficiency heat pumps will reduce overall energy consumption but have less of an impact on peak demand since, during the coldest temperatures, the efficiency of heat pumps declines, and some homes and businesses will require supplemental heat from other sources.

System Losses

Delivering electricity from generation sources to customers happens in three stages

- high voltage transmission
- transformation to lower voltages
- distribution to the customers at standard service voltages

There are losses at each of these stages. Many factors play into losses such as the physical distance from the generation source to the customers, technical characteristics of the transmission and distribution systems and load level.

The basis of the forecast energy losses on the transmission system is the Open Access Transmission Tariff⁷² loss factor of 3.3 per cent. This amount is assumed to remain constant over the forecast period. Loss factors or percentages are multiplied by the amount of energy delivered over the system to meet NB Power's total energy requirements.

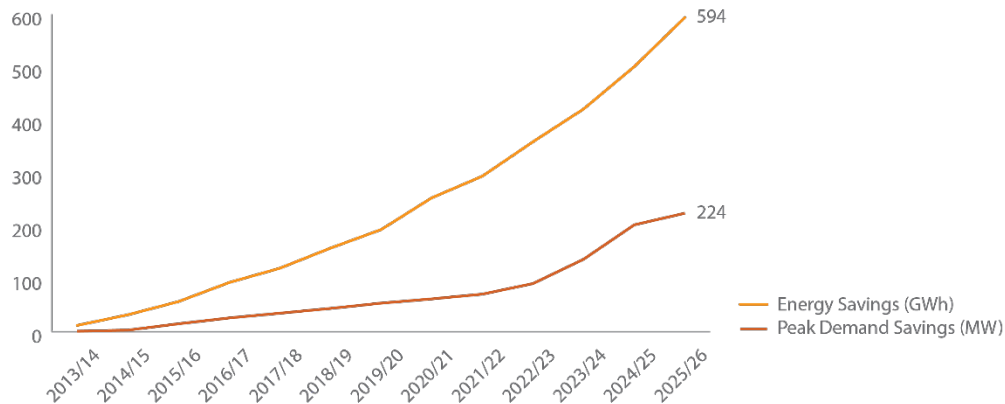
Distribution losses are forecast based on an analysis of the energy supplied over the distribution system compared to billed distribution sales. Energy losses on the distribution system are estimated to be 3.7 per cent of the total distribution sales over the forecast period. In addition, a substation transformer loss factor of 0.6 per cent is applied to all distribution energy requirements, for a total of 4.3 per cent forecasted distribution loss.

Demand Side Management (DSM)

Through investments in energy efficiency programs, NB Power has seen over 594 GWh of energy savings and 224 MW of peak demand savings achieved between 2012/13 and 2025/26.

⁷² The NB Power OATT provides a real power loss factor, which is applied to all transmission service within NB and is subject to approval by the New Brunswick Energy and Utilities Board.

Figure F.6: Historical DSM Savings



The Government of New Brunswick has regulated energy efficiency targets growing to a reduction of 0.75 per cent of annual sales by 2028/29 and each year thereafter. Demand side management programs will help customers manage their energy costs and lower overall energy requirements by approximately 13 per cent over the period ending in 2046/47. Projected energy savings for the forecast period are presented in Figure F.6.

Base Load Forecast

The total customer load in the base load forecast is determined by combining the total electricity consumption of the six customer classifications and the transmission and distribution losses related to delivering that electricity.

Beyond 2035/36, the forecast is escalated by class, with time-series regression models to project future load growth. Using forecasts for each customer sector, the data is combined to create the total in-province load forecast. The forecast includes estimates of conservation measures that consumers are anticipated to implement on their own without a demand side management program offering from NB Power.

High Load Growth Forecast

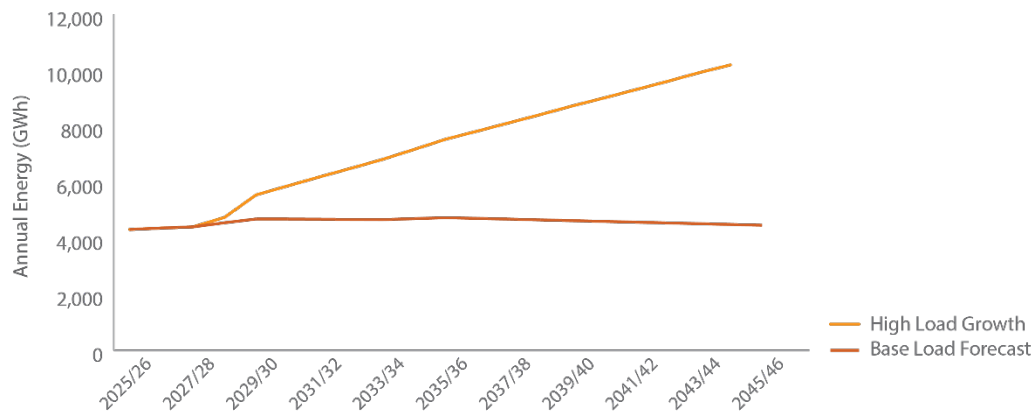
The high load growth scenario is the base load forecast plus high industrial load growth and enhanced electric vehicle adoption.

High Industrial Load Growth

In the base load forecast, the estimated incremental energy requirements for electrification of industrial processes and other loads traditionally served by non-electric energy sources are added to firm industrial transmission sales forecast as unallocated growth, beginning in 2025/26.

The high load growth forecast considers the potential for higher industrial electrification and large new loads such as manufacturing, data centres, mining, hydrogen/ammonia production other new industries or firm export sales. The high load growth forecast adds 800 MW to the base load forecast between 2029/30 and 2045/46 to represent the potential of emerging industries or firm export sales. The breadth of these forecasts is intended to capture the uncertainty around the potential volume of new industrial loads in the future. Figure F.7 shows the base load forecast and high load growth projection for industrial energy sales.

Figure F.7: Projections of Industrial Energy Sales



Enhanced Electric Vehicle Adoption

Growing adoption of electric vehicles is expected to have an impact on energy and demand forecasts in New Brunswick into the future.

Table F.1 provides a comparison of electric vehicle (EV) penetration in the base load forecast and in the case of enhanced EV adoption.

The IRP assumes 80 per cent of light duty vehicle (LDV) charging would occur at home and 20 per cent would be represented as general service sales. Medium duty vehicle (MDV), heavy duty vehicle (HDV) and bus charging are expected to occur as general service, industrial distribution or industrial transmission sales.

Table F.1: Electric Vehicle Energy Sales (GWh)

Year	Base Load Forecast (GWh)				Enhanced EV Adoption (GWh)			
	LDV	MDV	HDV	Bus	LDV	MDV	HDV	Bus
2025/26	26	5	2	5	41	7	5	6
2035/36	750	113	96	109	1,227	134	131	128
2045/46	1,987	341	381	265	2,830	377	499	285

Figure F.8 shows the combined annual electric vehicle energy requirements of the base load forecast compared to the scenario of enhanced EV adoption.

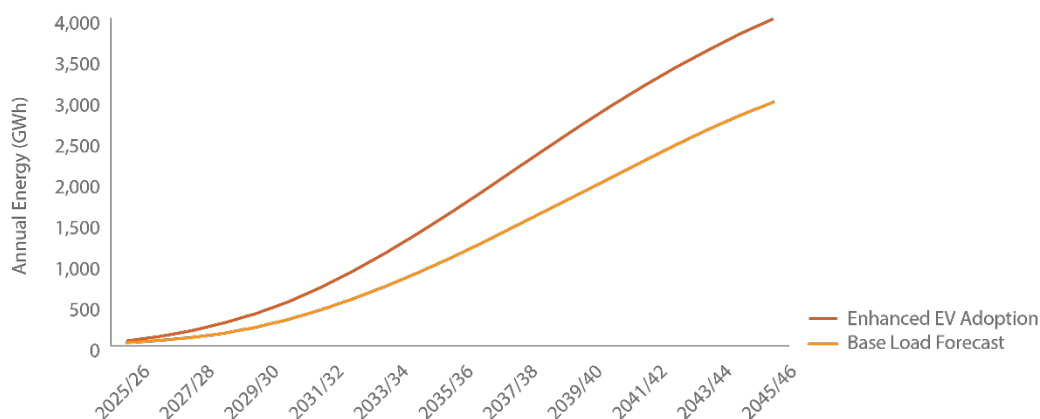
The base load forecast scenario is based on limited action to increase EV adoption, including

- keeping existing incentive levels
- maintaining the current pace of charging infrastructure growth
- removing federal and provincial zero-emission vehicle (ZEV) mandates

The enhanced forecast is based on more moderate support to enable EV adoption, including

- continuing government EV incentives until 2030
- deploying additional chargers
- delaying, but not rescinding, the ZEV mandate to 2040

Figure F.8: Projections of Electric Vehicle Annual Energy Requirements



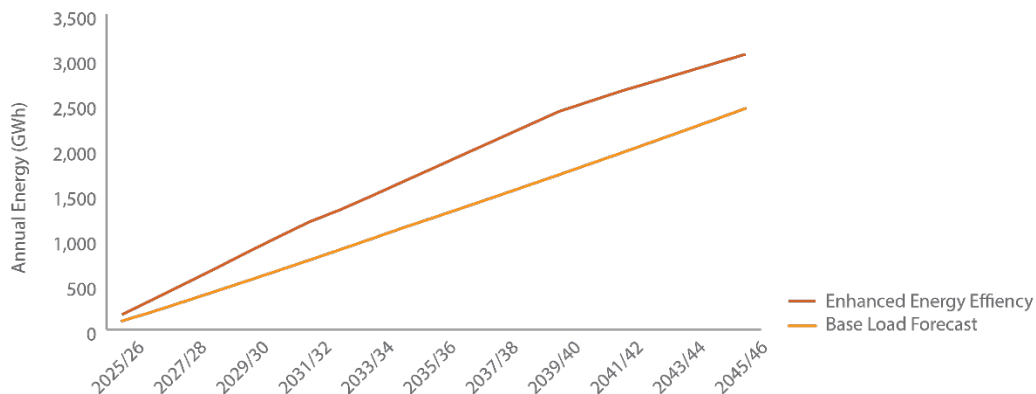
Low Load Growth Forecast

The low load growth scenario is the base load forecast plus enhanced energy efficiency savings and distributed generation.

Enhanced Energy Efficiency Savings

In the base load forecast, energy efficiency savings are based on a 'business as usual' forecast, achieving regulated energy efficiency targets with enabling activities and incentives in line with current programs. The enhanced energy efficiency forecast is based on a scenario with higher incentive levels that reflect a feasible higher incentive level, as a percentage of incremental costs, than current program design, which would promote greater program participation and savings. The increases in incentive levels vary by program from no change - where incentives are already 100 per cent of incremental costs – to tripling current incentive levels. Figure F.9 shows the base load forecast and enhanced energy efficiency savings projection.

Figure F.9: Projections of Energy Efficiency Savings



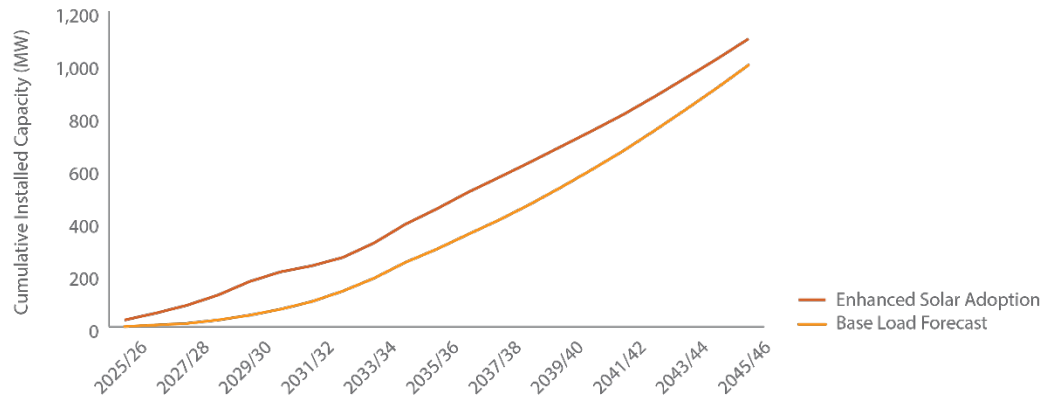
Enhanced Distributed Generation

The base load forecast for distributed generation is based on conservative behind-the-meter solar uptake without any government incentives and a revised program design.

The enhanced distributed generation forecast is based on increased behind-the-meter solar uptake with the provision of equipment incentives equal to nine to 36 per cent of incremental costs until 2029/30 and a redesigned program for customers with behind-the-meter generation.

Figure F.10 shows the base load forecast and enhanced solar adoption projection.

Figure F.10: Projections of Solar Cumulative Installed Capacity



Final Load Forecasts

Figure F.11 and Figure F.12 present the provincial energy forecast and provincial peak demand forecast indicating the

- base load forecast
- projected high load growth based on high industrial load growth and enhanced electric vehicle adoption
- projected low load growth based on enhanced energy efficiency savings and distributed generation.

Figure F.11: Provincial Energy Forecast

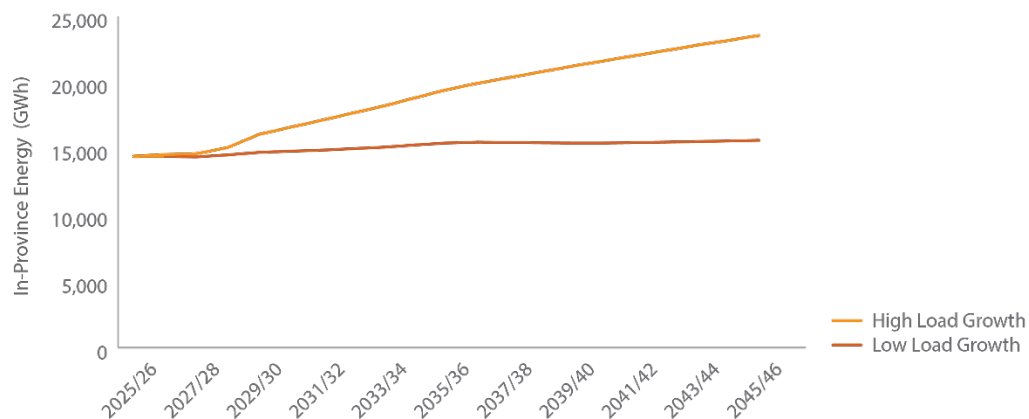
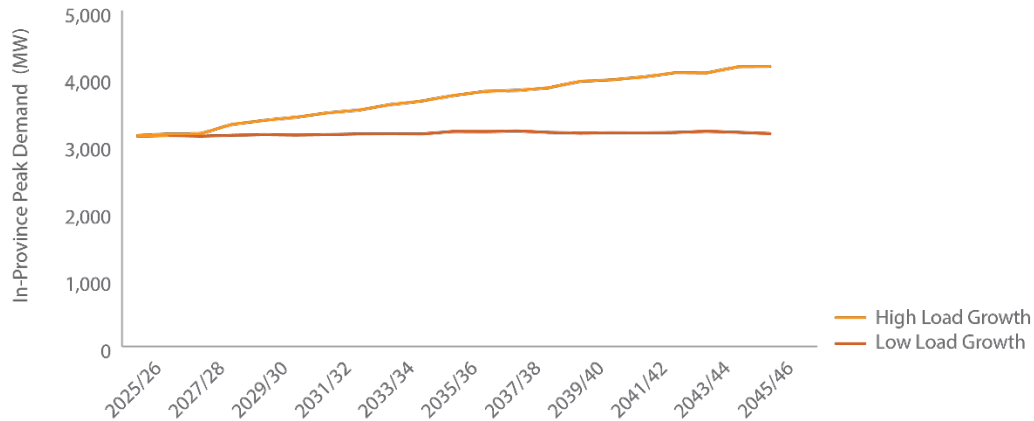


Figure F.12: Provincial Peak Demand Forecast⁷³



Meeting Demand

The IRP analysis is based on these forecasts to build supply plans that meet the load demand for each scenario.

Energy requirements are expected to increase across all scenarios, with considerably more growth in the high load growth forecast

- the average growth rate for energy is 2.4 per cent per year for the high load growth forecast and 0.3 per cent per year for low load growth
- the average growth rate for peak demand is 1.4 per cent per year for the high load growth forecast and 0.01 per cent per year for the low load growth forecast

Detailed load forecast data is included in Appendix G (Load Forecast Tables).

⁷³ Detailed transmission studies to determine requirements and costs associated with the high load growth scenario were not included in the scope of the IRP.

Appendix G – Load Forecast Tables

Forecasted Energy after Demand Side Management Savings
(GWh)

Year	Scenario A	Scenario B	Scenario C	Scenario D
2026/27	14,567	14,567	14,428	14,428
2027/28	14,632	14,632	14,389	14,389
2028/29	15,089	15,089	14,536	14,536
2029/30	16,081	16,081	14,730	14,730
2030/31	16,618	16,618	14,821	14,821
2031/32	17,146	17,146	14,894	14,894
2032/33	17,694	17,694	15,009	15,009
2033/34	18,229	18,229	15,118	15,118
2034/35	18,844	18,844	15,292	15,292
2035/36	19,448	19,448	15,437	15,437
2036/37	19,943	19,943	15,498	15,498
2037/38	20,365	20,365	15,476	15,476
2038/39	20,786	20,786	15,456	15,456
2039/40	21,219	21,219	15,435	15,435
2040/41	21,614	21,614	15,435	15,435
2041/42	22,014	22,014	15,465	15,465
2042/43	22,402	22,402	15,500	15,500
2043/44	22,802	22,802	15,542	15,542
2044/45	23,163	23,163	15,590	15,590
2045/46	23,544	23,544	15,637	15,637

Forecasted Demand Side Management Savings
(GWh)

Scenario A	Scenario B	Scenario C	Scenario D
200	200	336	336
312	312	507	507
425	425	678	678
539	539	855	855
654	654	1,026	1,026
770	770	1,194	1,194
888	888	1,330	1,330
1,007	1,007	1,482	1,482
1,128	1,128	1,639	1,639
1,243	1,243	1,794	1,794
1,360	1,360	1,951	1,951
1,478	1,478	2,106	2,106
1,597	1,597	2,262	2,262
1,716	1,716	2,418	2,418
1,837	1,837	2,532	2,532
1,958	1,958	2,645	2,645
2,081	2,081	2,747	2,747
2,204	2,204	2,850	2,850
2,328	2,328	2,953	2,953
2,454	2,454	3,055	3,055

Forecasted Demand after Demand Side Management Savings (MW)					Forecasted Demand Side Management Savings (MW)			
Year	Scenario A	Scenario B	Scenario C	Scenario D	Scenario A	Scenario B	Scenario C	Scenario D
2026/27	3,163	3,163	3,140	3,140	45	45	76	76
2027/28	3,168	3,168	3,130	3,130	70	70	114	114
2028/29	3,307	3,307	3,142	3,142	95	95	152	152
2029/30	3,363	3,363	3,152	3,152	120	120	191	191
2030/31	3,412	3,412	3,146	3,146	146	146	229	229
2031/32	3,475	3,475	3,152	3,152	171	171	265	265
2032/33	3,519	3,519	3,162	3,162	197	197	295	295
2033/34	3,599	3,599	3,166	3,166	223	223	328	328
2034/35	3,653	3,653	3,162	3,162	250	250	363	363
2035/36	3,736	3,736	3,200	3,200	274	274	395	395
2036/37	3,795	3,795	3,197	3,197	298	298	427	427
2037/38	3,811	3,811	3,207	3,207	322	322	459	459
2038/39	3,850	3,850	3,185	3,185	347	347	491	491
2039/40	3,946	3,946	3,174	3,174	371	371	523	523
2040/41	3,968	3,968	3,179	3,179	396	396	546	546
2041/42	4,010	4,010	3,177	3,177	421	421	569	569
2042/43	4,074	4,074	3,184	3,184	446	446	589	589
2043/44	4,070	4,070	3,202	3,202	472	472	610	610
2044/45	4,164	4,164	3,186	3,186	498	498	631	631
2045/46	4,167	4,167	3,167	3,167	523	523	652	652

Appendix H – Project and Operating Cost Parameters

Technology	Installed Capacity (MW)	"Marginal Effective Load Carrying Capability (ELCC)"	Capacity Factor (%)	In-Service Cost (\$/kW)	Expected Life (Years)	Heat Rate (MMBtu/MWh)	CO2 Intensity (t/GWh)	LCOE - Capital (\$/MWh)	LCOE - FO&M (\$/MWh)	LCOE - VO&M (\$/MWh)	"LCOE - Fuel (\$/MWh) (includes transmission)"	LCOE - CO2 Cost (\$/MWh)	LCOE - Transmission System Upgrade Adder (\$/MWh)	LCOE - Total (\$/MWh)	LCOC - Total (\$/kW-month)
Residential Solar PV	0.004	0%	10%	3,091	30	0	0	260	44	0	0	0	0	304	NA
Bayside Simple Cycle Extension	150	100%	5%	408	11	9,294	493	144	208	0	204	44	0	600	8
Demand Response Tranche 1	146	40%	0%	198	20	0	0	NA	NA	NA	NA	NA	NA	NA	18
Dual-fuel CT	100	100%	5%	3,986	30	9,124	500	636	40	11	177	44	0	908	25
Li-ion Battery (4-Hour) Utility Scale	100	58%	13%	1,892	20	1,250	0	141	9	0	118	0	0	268	25
Hydrogen CT	100	100%	5%	4,387	30	10,375	0	700	40	11	498	0	0	1,249	27
Bayside Combined Cycle Extension	270	100%	80%	312	11	7,000	385	7	8	0	146	20	0	181	29
Flow Battery	100	58%	23%	2,682	20	1,500	0	109	10	0	142	0	0	262	30
Compressed Air Energy Storage	100	58%	24%	2,639	35	1,500	0	88	15	0	211	0	0	313	31
Combined Cycle Gas Turbine	500	100%	80%	3,401	30	6,348	340	34	8	4	130	20	0	196	48
Pumped Storage	100	100%	27%	4,964	50	1,250	0	127	18	1	178	0	0	324	57
Biofuel	50	100%	60%	7,063	30	0	0	94	62	10	0	0	0	167	68
Combined Cycle Gas Turbine Carbon Capture	500	100%	80%	6,601	30	7,191	34	66	14	8	142	0	0	229	70
Li-ion Battery (4-Hour) Utility Scale Tranche 2	100	18%	13%	1,892	20	1,250	0	141	9	0	118	0	0	268	78
Demand Response Tranche 2	212	17%	0%	642	20	0	0	NA	NA	NA	NA	NA	NA	NA	104
Large Nuclear	750	100%	93%	14,110	50	10,000	0	106	47	6	9	0	8	177	122
Onshore Wind	30	16%	40%	2,248	30	0	0	45	14	0	0	0	9	68	126
Geothermal	100	100%	80%	18,276	30	0	0	182	46	0	0	0	0	229	133
Small Nuclear	100	100%	93%	21,474	50	10,000	0	162	37	6	9	0	8	221	159
Solar PV Utility Scale	50	8%	17%	1,834	30	0	0	86	16	0	0	0	11	113	176
Offshore Wind	400	31%	48%	11,636	30	0	0	195	28	0	0	0	8	231	256

Appendix I – Expansion Tables

Base Case Scenario A: High Load Growth/ Net-Zero 2050 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	100	702	-	146
2032/33	-	527	-	500	100	902	-	146
2033/34	-	527	-	500	300	902	-	146
2034/35	-	527	-	500	400	1,002	-	146
2035/36	-	527	-	500	500	1,202	-	146
2036/37	-	527	-	600	500	1,502	500	146
2037/38	-	527	-	600	500	1,502	500	146
2038/39	-	527	270	600	500	1,702	500	146
2039/40	-	527	270	600	500	1,702	500	146
2040/41	-	117	270	1,800	500	2,502	500	146
2041/42	-	117	270	1,800	500	2,502	500	146
2042/43	-	117	270	1,900	500	2,702	600	146
2043/44	-	117	270	1,900	500	2,702	600	146
2044/45	-	117	270	2,000	500	2,802	900	146
2045/46	-	117	270	2,000	500	2,802	900	146

Base Case Scenario B: High Load Growth/ Net-Zero 2035 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	100	702	-	146
2032/33	-	527	-	500	100	902	-	146
2033/34	-	527	-	500	300	902	-	146
2034/35	-	527	-	500	400	1,002	200	146
2035/36	-	527	-	500	500	1,002	400	146
2036/37	-	527	-	600	500	1,502	500	146
2037/38	-	527	-	600	500	1,502	500	146
2038/39	-	527	150	600	500	1,702	600	146
2039/40	-	527	150	600	500	1,702	600	146
2040/41	-	117	150	1,900	500	2,402	1,200	146
2041/42	-	117	150	2,000	500	2,402	1,200	146
2042/43	-	117	150	2,000	500	2,602	1,400	146
2043/44	-	117	150	2,000	500	2,602	1,400	146
2044/45	-	117	150	2,100	500	2,802	1,500	146
2045/46	-	117	150	2,100	500	2,802	1,500	146

Base Case Scenario C: Low Load Growth/ Net-Zero 2050 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	-	702	-	-
2032/33	-	527	-	500	-	702	-	-
2033/34	-	527	-	500	-	702	-	-
2034/35	-	527	-	500	-	702	-	-
2035/36	-	527	-	500	-	702	-	-
2036/37	-	527	-	500	-	702	-	-
2037/38	-	527	-	500	-	702	-	-
2038/39	-	527	150	500	-	702	-	-
2039/40	-	527	150	500	-	702	-	-
2040/41	-	117	150	1,000	500	1,102	500	146
2041/42	-	117	150	1,000	500	1,102	500	146
2042/43	-	117	150	1,000	500	1,302	500	146
2043/44	-	117	150	1,000	500	1,302	500	146
2044/45	-	117	150	1,000	500	1,302	500	146
2045/46	-	117	150	1,000	500	1,302	500	146

Base Case Scenario D: Low Load Growth/ Net-Zero 2035 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	-	702	-	-
2032/33	-	527	-	500	-	702	-	-
2033/34	-	527	-	500	-	702	-	-
2034/35	-	527	-	500	-	702	-	-
2035/36	-	527	-	500	-	702	-	-
2036/37	-	527	-	500	-	702	-	-
2037/38	-	527	-	500	-	702	-	-
2038/39	-	527	150	500	-	702	100	-
2039/40	-	527	150	500	-	702	100	-
2040/41	-	117	150	1,000	500	1,102	500	146
2041/42	-	117	150	1,000	500	1,102	500	146
2042/43	-	117	150	1,000	500	1,202	500	146
2043/44	-	117	150	1,000	500	1,202	500	146
2044/45	-	117	150	1,000	500	1,202	600	146
2045/46	-	117	150	1,000	500	1,202	600	146

New Nuclear Scenario A: High Load Growth/ Net-Zero 2050 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	600	-	702	-	146
2032/33	-	527	-	600	-	902	-	146
2033/34	-	527	-	700	-	902	-	146
2034/35	-	527	-	700	-	1,002	-	146
2035/36	-	527	-	700	200	1,102	-	146
2036/37	-	527	-	700	300	1,302	-	146
2037/38	-	527	-	700	300	1,302	-	146
2038/39	-	527	150	700	300	1,302	-	146
2039/40	750	527	150	700	300	1,302	-	146
2040/41	750	117	150	1,200	500	1,302	200	146
2041/42	750	117	150	1,300	500	1,302	200	146
2042/43	750	117	150	2,000	500	2,302	500	146
2043/44	750	117	150	2,000	500	2,302	500	146
2044/45	1,500	117	150	2,000	500	2,302	500	146
2045/46	1,500	117	150	2,000	500	2,302	500	146

New Nuclear Scenario B: High Load Growth/ Net-Zero 2035 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	600	-	702	-	146
2032/33	-	527	-	600	-	902	-	146
2033/34	-	527	-	700	-	902	-	146
2034/35	-	527	-	700	-	1,002	-	146
2035/36	-	527	-	700	200	1,102	-	146
2036/37	-	527	-	700	300	1,302	-	146
2037/38	-	527	-	700	300	1,302	-	146
2038/39	-	527	150	700	300	1,302	-	146
2039/40	750	527	150	700	300	1,302	-	146
2040/41	750	117	150	1,200	500	1,302	200	146
2041/42	750	117	150	1,300	500	1,302	200	146
2042/43	750	117	150	2,000	500	2,302	500	146
2043/44	750	117	150	2,000	500	2,302	500	146
2044/45	1,500	117	150	2,000	500	2,302	500	146
2045/46	1,500	117	150	2,000	500	2,302	500	146

New Nuclear Scenario C: Low Load Growth/ Net-Zero 2050 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	-	702	-	-
2032/33	-	527	-	500	-	702	-	-
2033/34	-	527	-	500	-	702	-	-
2034/35	-	527	-	500	-	702	-	-
2035/36	-	527	-	500	-	702	-	-
2036/37	-	527	-	500	-	702	-	-
2037/38	-	527	-	500	-	702	-	-
2038/39	-	527	150	500	-	702	-	-
2039/40	750	527	150	500	-	702	-	-
2040/41	750	117	150	500	200	702	-	146
2041/42	750	117	150	500	200	702	-	146
2042/43	750	117	150	1,000	500	1,002	-	146
2043/44	750	117	150	1,000	500	1,002	-	146
2044/45	1,500	117	150	1,000	500	1,002	-	146
2045/46	1,500	117	150	1,000	500	1,002	-	146

New Nuclear Scenario D: Low Load Growth/ Net-Zero 2035 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	-	702	-	-
2032/33	-	527	-	500	-	702	-	-
2033/34	-	527	-	500	-	702	-	-
2034/35	-	527	-	500	-	702	-	-
2035/36	-	527	-	500	-	702	-	-
2036/37	-	527	-	500	-	702	-	-
2037/38	-	527	-	500	-	702	-	-
2038/39	-	527	150	500	-	702	-	-
2039/40	750	527	150	500	-	702	-	-
2040/41	750	117	150	500	200	702	-	146
2041/42	750	117	150	500	200	702	-	146
2042/43	750	117	150	1,000	500	1,002	-	146
2043/44	750	117	150	1,000	500	1,002	-	146
2044/45	1,500	117	150	1,000	500	1,002	-	146
2045/46	1,500	117	150	1,000	500	1,002	-	146

No Nuclear Scenario A: High Load Growth/ Net-Zero 2050 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	100	702	-	146
2032/33	-	527	-	500	100	902	-	146
2033/34	-	527	-	500	300	902	-	146
2034/35	-	527	-	500	400	1,002	-	146
2035/36	-	527	-	500	500	1,202	-	146
2036/37	-	527	-	600	500	1,502	400	146
2037/38	-	527	-	600	500	1,502	400	146
2038/39	-	527	270	600	500	1,702	400	146
2039/40	-	527	270	600	500	1,702	400	146
2040/41	-	117	270	1,800	500	2,502	500	146
2041/42	-	117	270	1,800	500	2,502	500	146
2042/43	-	117	270	2,500	500	3,702	700	146
2043/44	-	117	270	2,500	500	3,702	900	146
2044/45	-	117	270	2,600	500	3,802	1,100	146
2045/46	-	117	270	2,600	500	3,802	1,500	146

No Nuclear Scenario B: High Load Growth/ Net-Zero 2035 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	600	-	702	-	146
2032/33	-	527	-	600	-	1,002	-	146
2033/34	-	527	-	600	200	1,002	-	146
2034/35	-	527	-	600	300	1,102	-	146
2035/36	-	527	-	600	400	1,402	-	146
2036/37	-	527	-	600	500	1,802	200	146
2037/38	-	527	-	600	500	1,802	200	146
2038/39	-	527	150	600	500	1,902	200	146
2039/40	-	527	150	600	500	1,902	200	146
2040/41	-	117	150	1,900	500	2,502	500	146
2041/42	-	117	150	1,900	500	2,502	500	146
2042/43	-	117	150	2,600	500	3,702	1,100	146
2043/44	-	117	150	2,600	500	3,702	1,300	146
2044/45	-	117	150	2,700	500	3,702	1,600	146
2045/46	-	117	150	2,700	500	3,702	1,900	146

No Nuclear Scenario C: Low Load Growth/ Net-Zero 2050 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	-	702	-	-
2032/33	-	527	-	500	-	702	-	-
2033/34	-	527	-	500	-	702	-	-
2034/35	-	527	-	500	-	702	-	-
2035/36	-	527	-	500	-	702	-	-
2036/37	-	527	-	500	-	702	-	-
2037/38	-	527	-	500	-	702	-	-
2038/39	-	527	270	500	-	702	-	-
2039/40	-	527	270	500	-	702	-	-
2040/41	-	117	270	1,000	500	1,102	500	146
2041/42	-	117	270	1,000	500	1,102	500	146
2042/43	-	117	270	1,600	500	2,102	500	146
2043/44	-	117	270	1,600	500	2,102	600	146
2044/45	-	117	270	1,600	500	2,102	800	146
2045/46	-	117	270	1,600	500	2,102	1,100	146

No Nuclear Scenario D: Low Load Growth/ Net-Zero 2035 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	-	702	-	-
2032/33	-	527	-	500	-	702	-	-
2033/34	-	527	-	500	-	702	-	-
2034/35	-	527	-	500	-	702	-	-
2035/36	-	527	-	500	-	702	-	-
2036/37	-	527	-	500	-	702	-	-
2037/38	-	527	-	500	-	702	-	-
2038/39	-	527	150	500	-	702	100	-
2039/40	-	527	150	500	-	702	100	-
2040/41	-	117	150	1,000	500	1,102	500	146
2041/42	-	117	150	1,000	500	1,102	500	146
2042/43	-	117	150	1,600	500	2,102	1,100	146
2043/44	-	117	150	1,700	500	2,102	1,100	146
2044/45	-	117	150	1,700	500	2,102	1,300	146
2045/46	-	117	150	1,700	500	2,102	1,500	146

Increased Interconnection Scenario A: High Load Growth/ Net-Zero 2050 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	100	702	-	146
2032/33	-	527	-	500	100	902	-	146
2033/34	-	527	-	500	300	902	-	146
2034/35	-	527	-	500	400	1,002	-	146
2035/36	-	527	-	600	400	1,202	-	146
2036/37	-	527	-	600	500	1,602	-	146
2037/38	-	527	-	600	500	1,602	-	146
2038/39	-	527	150	600	500	1,802	-	146
2039/40	-	527	150	600	500	1,802	-	146
2040/41	-	117	150	1,900	500	2,402	500	146
2041/42	-	117	150	2,000	500	2,402	500	146
2042/43	-	117	150	2,000	500	2,602	500	146
2043/44	-	117	150	2,000	500	2,602	500	146
2044/45	-	117	150	2,100	500	2,802	700	146
2045/46	-	117	150	2,100	500	2,802	700	146

Increased Interconnection Scenario B: High Load Growth/ Net-Zero 2035 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	100	702	-	146
2032/33	-	527	-	500	100	902	-	146
2033/34	-	527	-	500	300	902	-	146
2034/35	-	527	-	500	400	1,002	-	146
2035/36	-	527	-	600	500	1,302	-	146
2036/37	-	527	-	600	500	1,802	100	146
2037/38	-	527	-	600	500	1,802	100	146
2038/39	-	527	150	600	500	1,802	100	146
2039/40	-	527	150	600	500	1,802	100	146
2040/41	-	117	150	1,900	500	2,402	500	146
2041/42	-	117	150	2,000	500	2,402	500	146
2042/43	-	117	150	2,000	500	2,602	500	146
2043/44	-	117	150	2,000	500	2,602	500	146
2044/45	-	117	150	2,100	500	2,702	800	146
2045/46	-	117	150	2,100	500	2,702	800	146

Increased Interconnection Scenario C: Low Load Growth/ Net-Zero 2050 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	-	702	-	-
2032/33	-	527	-	500	-	702	-	-
2033/34	-	527	-	500	-	702	-	-
2034/35	-	527	-	500	-	702	-	-
2035/36	-	527	-	500	-	702	-	-
2036/37	-	527	-	500	-	702	-	-
2037/38	-	527	-	500	-	702	-	-
2038/39	-	527	150	500	-	702	-	-
2039/40	-	527	150	500	-	702	-	-
2040/41	-	117	150	1,000	500	1,202	400	146
2041/42	-	117	150	1,000	500	1,202	400	146
2042/43	-	117	150	1,000	500	1,302	400	146
2043/44	-	117	150	1,000	500	1,302	500	146
2044/45	-	117	150	1,000	500	1,302	500	146
2045/46	-	117	150	1,000	500	1,302	500	146

Increased Interconnection Scenario D: Low Load Growth/ Net-Zero 2035 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	527	-	500	-	702	-	-
2030/31	-	527	-	500	-	702	-	-
2031/32	-	527	-	500	-	702	-	-
2032/33	-	527	-	500	-	702	-	-
2033/34	-	527	-	500	-	702	-	-
2034/35	-	527	-	500	-	702	-	-
2035/36	-	527	-	500	-	702	-	-
2036/37	-	527	-	500	-	702	-	-
2037/38	-	527	-	500	-	702	-	-
2038/39	-	527	150	500	-	802	-	-
2039/40	-	527	150	500	-	802	-	-
2040/41	-	117	150	1,000	500	1,202	400	146
2041/42	-	117	150	1,000	500	1,202	400	146
2042/43	-	117	150	1,000	500	1,302	400	146
2043/44	-	117	150	1,000	500	1,302	500	146
2044/45	-	117	150	1,000	500	1,302	500	146
2045/46	-	117	150	1,000	500	1,302	500	146

No Carbon Restriction Scenario A: High Load Growth/ Net-Zero 2050 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	117	-	500	-	702	-	-
2030/31	-	117	-	500	-	702	-	-
2031/32	-	117	-	500	-	702	-	146
2032/33	-	117	-	500	-	802	-	146
2033/34	-	117	-	600	100	802	-	146
2034/35	-	117	-	700	100	1,002	-	146
2035/36	-	117	-	700	200	1,002	-	146
2036/37	-	117	-	700	300	1,302	-	146
2037/38	-	117	-	700	300	1,302	-	146
2038/39	-	117	150	700	300	1,602	-	146
2039/40	-	117	150	700	300	1,602	-	146
2040/41	-	117	150	1,900	500	2,402	500	146
2041/42	-	117	150	1,900	500	2,402	500	146
2042/43	-	117	150	2,000	500	2,702	500	146
2043/44	-	117	150	2,000	500	2,702	500	146
2044/45	-	117	150	2,100	500	2,802	500	146
2045/46	-	117	150	2,100	500	2,802	500	146

No Carbon Restriction Scenario C: Low Load Growth/ Net-Zero 2050 (Installed Capacity Unit: MW)

	Nuclear	Biomass	Bayside Extension	Combustion Turbines	Batteries	Wind	Solar	Demand Response
2026/27	-	-	-	-	-	-	-	-
2027/28	-	-	-	500	-	50	-	-
2028/29	-	117	-	500	-	472	-	-
2029/30	-	117	-	500	-	702	-	-
2030/31	-	117	-	500	-	702	-	-
2031/32	-	117	-	500	-	702	-	-
2032/33	-	117	-	500	-	702	-	-
2033/34	-	117	-	500	-	702	-	-
2034/35	-	117	-	500	-	702	-	-
2035/36	-	117	-	500	-	702	-	-
2036/37	-	117	-	500	-	702	-	-
2037/38	-	117	-	500	-	702	-	-
2038/39	-	117	150	500	-	702	-	-
2039/40	-	117	150	500	-	702	-	-
2040/41	-	117	150	1,000	500	1,202	300	146
2041/42	-	117	150	1,000	500	1,202	300	146
2042/43	-	117	150	1,000	500	1,302	300	146
2043/44	-	117	150	1,000	500	1,302	500	146
2044/45	-	117	150	1,000	500	1,302	500	146
2045/46	-	117	150	1,000	500	1,302	500	146