Evaluating the Electric Grid Impacts of Offshore Wind in the Atlantic Provinces

July 2026 Report

Stantec

Energy+Environmental Economics

net-zero atlantic

Atlantic Canada Offshore Wind Grid Integration and Transmission Study

ACKNOWLEDGEMENTS

The Atlantic Canada Offshore Wind Grid Integration and Transmission Study is a research project developed and led by Net Zero Atlantic. This research is conducted by Stantec in partnership with Energy and Environmental Economics (E3) and is supported by funding from Natural Resources Canada's Office of Energy Research and Development through its Energy Innovation Program.

Letter from Net Zero Atlantic

Net Zero Atlantic is pleased to share the findings of the Atlantic Canada Offshore Wind Grid Integration and Transmission Study.

This report examines potential market and offtake opportunities for offshore wind development in Atlantic Canada and presents future electricity system scenarios modelled using PLEXOS, building on the Market Opportunities for Offshore Wind in the Atlantic Provinces report and PSSE modelling work conducted thereafter. Together with the study's broader technical, economic, and policy analyses, it contributes to a comprehensive assessment of how offshore wind can be integrated into Atlantic Canada's electricity systems and support long-term regional energy objectives.

Support for this work was provided by Natural Resources Canada's Office of Energy Research and Development through the Energy Innovation Program.

We thank consultants Stantec and Energy and Environmental Economics (E3) for their contributions throughout the study. Net Zero Atlantic is also greatly appreciative of the guidance and input provided by provincial governments and electrical utility representatives who participated on the project management and technical committees. We would also like to thank Dr. Lukas Swan of Charged Engineering for his valuable input and review of reports throughout the study.

The study has produced several key deliverables, including the Market Opportunities for Offshore Wind in the Atlantic Provinces report, the Actual Deployment Potential of Atlantic Canada Offshore Wind report, the Visual Interface Tool and associated database, the Preliminary Transmission Expansion Needs Analysis to Integrate Offshore Wind in Atlantic Canada report, the Roadmap and Action Plan for Integrating Offshore Wind into Atlantic Canada's Grid, and several other supporting reports. These resources can be accessed and downloaded through Net Zero Atlantic's website.

Thank you for your interest and engagement throughout this study. We greatly appreciate your support and look forward to continuing the conversation around the opportunities, challenges, and findings identified through this work.

Kiera Walsh, Project Manager
Sven Scholtysik, Research Director
Net Zero Atlantic

Summary of Updates from Draft Phase 1 Report

This report updates the initial Phase 1 assessment of offshore wind market opportunities and reflects continued progress through Phases 2 and 3 of the study. While many of the core findings remain consistent, this update incorporates refinements based on improved data, deeper analysis, and insights developed through ongoing collaboration with utilities and stakeholder committees. Phase 2 advanced the characterization of offshore wind resources using more detailed, site-specific data, while Phase 3 expanded the analysis to evaluate grid integration requirements, operational dynamics, and coordinated transmission expansion pathways. The updated work also includes a more refined assessment of system reliability and the role of offshore wind in meeting resource adequacy needs. Together, these enhancements provide a more robust and comprehensive view of offshore wind's potential, system interactions, and integration costs compared to the earlier Phase 1 report.

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Acronym Definitions & Notes

Acronym	Definition
ELCC	Effective Load Carrying Capability
GW	Gigawatt (1000 megawatts)
H2	Hydrogen
HQ	Hydro Québec
IRP	Integrated Resource Plan
ISO-NE	Independent System Operator for New England
LCOE	Levelized Cost of Energy
LIL	Labrador Island Link
NB	New Brunswick
NBP	New Brunswick Power
NL	Newfoundland & Labrador
NPV	Net Present Value
NS	Nova Scotia
NSPI	Nova Scotia Power Inc.
OBPS	Output-Based Pricing System
OSW	Offshore Wind
PEI	Prince Edward Island
PLEXOS LT	PLEXOS Long Term
POI	Point of Interconnection
PRM	Planning Reserve Margin
RA	Resource Adequacy
SMR	Small Modular Reactors
Tx	Transmission
UCAP	Unforced Capacity

All dollar values reported in this study are in Canadian nominal dollars.

Executive Summary

Federal regulations commit Canada to reducing greenhouse gas emissions by 40–45% below 2005 levels by 2030 and achieving net-zero emissions by mid-century. Meeting these goals will require a fundamental transformation in how energy is produced and consumed across the country. In the Atlantic Provinces, the power sector accounts for roughly one-quarter of total emissions, with fossil fuels still supplying about 15% of electricity generation today. However, near-term emissions targets and the continued buildout of renewables in the region are expected to drive substantial reductions by 2030. Beyond 2030, offshore wind presents a significant opportunity to further decarbonize the power sector, supporting progress toward net-zero emissions while also meeting rising electricity demand from the electrification of buildings, transportation, and industry.

Offshore wind power generation has many potential advantages: strong and stable output, proximity to demand, high technical potential relative to land-based resources, and zero carbon emissions. The extensive coastline of the Atlantic Provinces also boasts some of the highest performing offshore wind resources along the North American Eastern Seaboard, with particularly high output in the winter, the time when clean energy is needed most. Early investments in offshore wind provide an opportunity to create an offshore wind industry and jobs, leveraging the region's strong marine-oriented labor force and research expertise. This clean resource may also serve nascent industries like green hydrogen, building on plans to support European markets, or other industrial loads or data centers. While these opportunities hold promise, realizing offshore wind's potential will require a coordinated effort to address key challenges, including lowering the cost of offshore wind and building out the transmission infrastructure to transport clean electricity to sources of demand.

This document summarizes the approach and findings from the **market opportunity assessment for offshore wind** and **long-term electric grid capacity expansion and production cost modeling**, serving as a final deliverable within the *Atlantic Canada Offshore Wind Grid Integration and Transmission Study*, facilitated and managed by Net Zero Atlantic and funded by Natural Resources Canada. This document supports the assessment of the potential for a transformative GW-scale offshore wind industry in the Atlantic Provinces, with a long-term view from 2035-2050. The report summarizes the potential market and offtake opportunities for offshore wind, and models future scenarios in which offshore wind helps decarbonize domestic electricity consumption, export clean energy to neighboring markets, and serve growing industrial demand. It also explores the conditions in which expanded interprovincial transmission might lead to more efficient and cost-effective integration of offshore wind, and how that transmission might impact dispatch and utilization across the region.

The modeling approach evaluates long-term electricity demands and opportunities using an industry-leading electricity system capacity expansion model, PLEXOS-LT, as well as the detailed production cost model, PLEXOS ST. This ensures that scenario-based offshore wind planning targets are considered as part of the overall regional electricity system, simulating how offshore wind interacts with the rest of the existing and potential future resources on the grid. The model performs a least-cost optimization to meet demand with existing and potential future supply, including offshore wind targets. It integrates robust representation of candidate resources, and key operational, policy, transmission and other system constraints. This enables the evaluation of offshore wind targets and their impact on energy system costs, reliability, and emissions. Additionally, the study reviews detailed hourly simulations of the future electric grid, evaluating operational implications and integration investments. Findings from this analysis are discussed in the Electric Grid Production Cost Modeling results section.

The electric grid modeling and market analysis generated the following key findings:

1. **Offshore wind resources can meet significant regional electricity demand in Atlantic Canada, serving growing load and reducing fossil fuel dependence, including during winter periods in which demand is highest in the Atlantic Provinces.** Regional electricity demand may grow nearly 30% between 2025 and 2050, based on utility estimates of electrification. Policy drivers are also changing the grid, with output-based carbon pricing and mandates for about 1.8 GW of coal retirements by 2030. High-quality offshore wind (OSW) resources may support this transition in the mid to late 2030s and beyond, with the highest output during winter months of December to March when growing loads will continue to stress the system. Although many onshore wind projects are already planned and under construction, utilizing even a small portion of the offshore wind technical potential could play an important role in meeting growing energy demand and replacing retiring fossil fuel generation. This study modeled scenarios illustrating the potential for 1 GW of offshore wind to support domestic needs by 2035, growing to 2.5 GW later in the period. Additional hourly dispatch analysis found that scenarios with meaningful offshore wind development could further reduce fossil fuel utilization on an annual basis, though limited but critical firm dispatchable generation is still needed to maintain reliability.

2. **Given growing loads, decarbonization targets, and resource scarcity across the Northeast U.S. and Eastern Canada, Atlantic Canada's high performing offshore wind resources have the potential to meet GW-scale clean energy demands in neighboring regions.** Load growth, driven by end-use electrification, large load development, and population growth, is putting significant upward pressure on resource supply options in both Canada and the Northeastern U.S. Simultaneously, these regions are pursuing deep decarbonization targets, requiring substantial reductions in fossil fuel reliance across the next 10-20 years, while also managing affordability concerns amid inflation and volatile global energy prices. These overlapping pressures are driving demand for clean energy across the broader region, particularly resources that can reliably deliver during scarce winter periods. For example, many New England planning scenarios project a need for at least 100 GW of clean electricity generation capacity, including over 30 GW of offshore wind by 2050[1]. This scale of development would be challenging to achieve under any circumstances but has only gotten harder in the face of obstructive U.S. federal action that is currently preventing further offshore wind development in U.S. waters. Considering all these factors, offshore wind from Atlantic Canada is very well suited to contribute to these needs, given its high capacity factor and close proximity to New England. Other markets, such as

[1] For examples, see ISO-NE's 2050 Transmission Planning Study: 2024_02_14_pac_2050_transmission_study_final.pdf and Massachusetts 2050 Clean Energy and Climate Plan (CECP): Clean Energy and Climate Plan for 2050

Québec and Ontario, could also benefit from the diversity offshore wind provides, particularly at a time when drought conditions limit the abundant hydro generation that has historically fueled growth there. However, large-scale exports will require significant new transmission to these other regions of Canada or across the US border; coordinating transmission investments at scale across regions will be challenging but is critical to realizing this opportunity. This study explores scenarios that support 2 GW of offshore wind export capacity by 2035, 4.5 GW by 2040, and 6 GW by 2050. While export opportunities involve greater investment, coordination, and cost, they could deliver valuable regional benefits.

3. **Offshore wind has the potential to help attract and grow industrial load investments (e.g., hydrogen) in the Atlantic provinces, representing a significant, albeit still emerging and therefore uncertain, market opportunity.** Industrial loads like hydrogen, or other large electric demands, have emerged as a major economic development opportunity and energy planning challenge for communities and grids across North America in recent years. This is being driven by data center development, emerging manufacturing sectors such as advanced chip production, and industrial developments including green hydrogen. Green hydrogen, produced using renewable electricity to split water into hydrogen and oxygen, is one of the few commercially proven technologies that could enable decarbonization of hard-to-abate sectors like heavy industry, long-haul transport, aviation, and shipping, as well as support electricity demand during periods of high load and low renewable output. The market, trading systems, and supply chains to support green hydrogen are in their infancy, but efforts are underway to accelerate development in Canada and other global markets, with government and private sector support.[2] This study modeled scenarios with green hydrogen industrial loads and found synergistic development opportunities between green hydrogen development and regional offshore wind – namely that development of one could help unlock development of the other. It's worth noting that while this was parameterized based on hydrogen load characteristics in this study, conclusions from that analysis could apply to any large load development in the region.

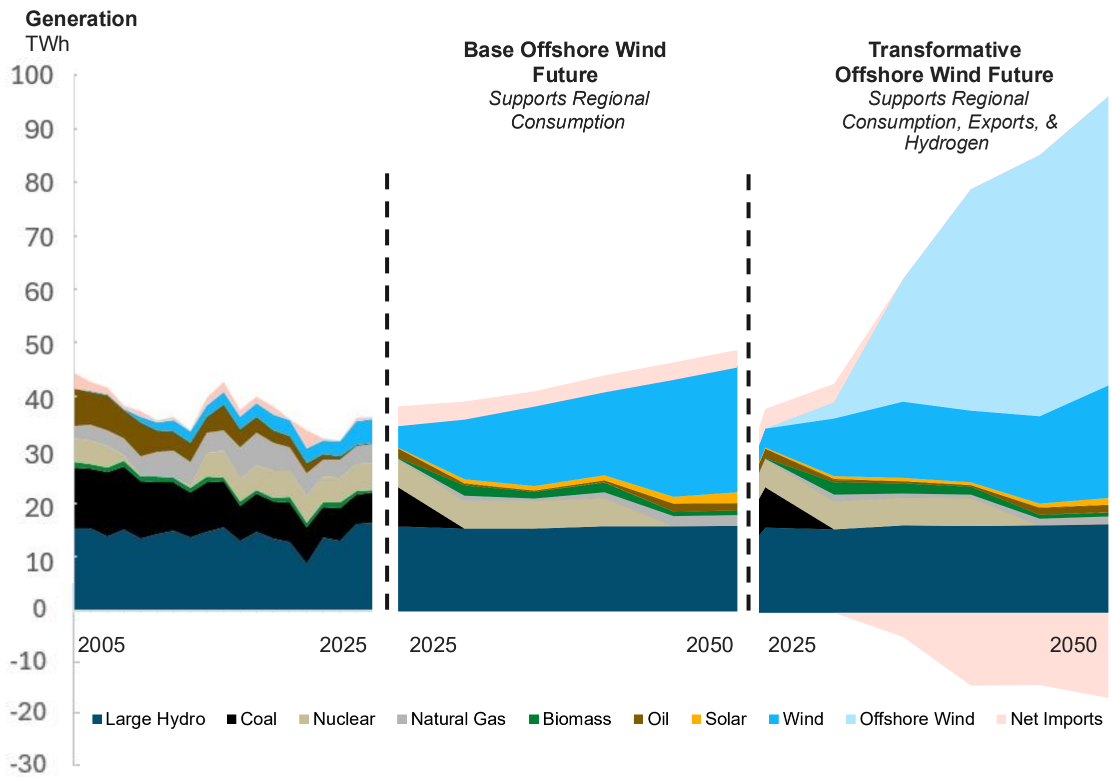
   Industrial load growth, modeled as green hydrogen, represents the largest market opportunity for offshore wind that was explored in this study, but the growth of this emerging industry is difficult to predict. Thus, this study evaluated a range of demand levels, from about 15 to 40 TWh in 2035, rising to 30 to 70+ TWh by 2050 to support green hydrogen production. This level of investment could support up to 1.4 million tonnes of green hydrogen per year by 2050, enabled by a combination of onshore and offshore wind, with offshore wind playing a growing role over time. Specifically, scenarios modeled offshore wind builds to support hydrogen ranging from 2 to 4.5 GW in 2035, to 4 to 8 GW by 2050.

   Figure ES-1 illustrates a range of possible futures for offshore wind. The middle of the figure demonstrates a future in which offshore wind supports regional consumption but is not exported

[2] For example, Canada and Germany signed a hydrogen alliance in 2022, and in 2024, Canada committed $300 million to support hydrogen trade. See: https://www.canada.ca/en/natural-resources-canada/news/2022/08/canada-and-germany-sign-agreement-to-enhance-german-energy-security-with-clean-canadian-hydrogen.html
Government of Canada Announces $300 Million in Port Hawkesbury on Canada - Germany Hydrogen Alliance - Canada.ca

to neighboring jurisdictions or used to supply growing industrial loads. Alternatively, a future in which offshore wind supports regional needs, export markets, and significant industrial load growth is shown on the far right in Figure ES-1 below, illustrating the dramatic transformation this would imply for the region.

Figure ES-1. Electric Grid in Atlantic Provinces Has Begun Significant Transformation, And Will Change Dramatically in the Next Decade



Notes: The left column reflects historical regional data from Canada's Energy Future, 2023. The middle figure shows the "Domestic-only" scenario, which includes supporting offshore wind primarily for use in the Atlantic provinces. The right column shows the "All Markets" scenario, which includes supporting domestic consumption, export markets and hydrogen demand. Note that the model added transmission/export capability and hydrogen demand at five-year increments, contributing to "jumps" in demand in the third column/scenario. The model also curtails excess energy (not shown in graph) contributing to variation in output as some onshore and offshore wind are curtailed when their output exceeds total demand.

4. **Building an offshore wind industry requires substantial investment to reduce project costs, which today have capital costs substantially higher than land-based wind projects.** While offshore wind benefits from higher energy output due to the use of larger turbines and often more consistent wind patterns, these larger turbines contribute to higher up-front capital costs, which will put upward pressure on regional electric rates if not addressed (e.g., through cost reductions or federal support). Additionally, constructing wind farms in marine environments, whether fixed to undersea foundations or floating on platforms, necessitates complex infrastructure to withstand harsh marine conditions. Transmission is similarly more expensive offshore than on

land. Atlantic Canada, with its well-developed ports and marine-oriented industries, labor force, and research organizations, has the potential to contribute to the learning-by-doing required to lower the cost of offshore wind. That said, the offshore wind industry's nascency in North America still creates longer project timelines and risks compared to land-based wind. While Europe has developed significant offshore wind resources, less than 1 GW of offshore wind is operational in North America today, though several GW of offshore wind are planned or under construction. This nascency, as well as greater uncertainty related to weather and operational risks, translates to higher costs. Finally, offshore wind costs and capabilities must compete with clean energy alternatives, including onshore wind, new hydro and small modular reactors. As discussed in the report body, these technologies may provide complementary features to support load growth and the gaps left by retiring coal but will compete for capital to meet offtake opportunities in Atlantic Canada and in neighboring regions.

5. **To maximize regional benefits of large-scale offshore wind development, coordinated transmission investment will be essential for ensuring efficient power delivery to load, both within the Atlantic Provinces and to neighboring regions.** Current interties between provinces are limited and frequently constrained, restricting the ability to share excess power between provinces and increasing curtailment at higher offshore wind deployment levels. To assess the value of relieving these constraints, Phase 3 included supplemental transmission expansion scenarios in which interprovincial interfaces were allowed to expand endogenously. Interprovincial transmission was found to provide economic benefits under the more transformative scenarios—those with large volumes of offshore wind additions and substantial industrial load development. In these cases, expanded transmission helps to reduce both investment and operational costs. Investment savings stem from more efficient sharing of offshore wind across provinces, reducing the need for some local solar, storage, and thermal builds. Operational savings stem from lower curtailment and reduced reliance on thermal generation, as expanded interties allow excess offshore wind to be utilized rather than spilled and to displace higher-cost generation. These findings underscore transmission as a critical enabler of cost-effective offshore wind integration when deployed at scale. In lower deployment scenarios, interprovincial transmission was not found to be economic; such transmission is itself a major investment and should only be undertaken if the benefits are sufficient to offset those costs.

6. **Detailed production cost analysis highlights the opportunities and challenges of operating a wind dominant system; offshore wind can meet most need during many periods of the year, but dispatchable generation remains critical for reliability during periods of low wind output.** Hourly production cost modeling shows that modeled resource portfolios meet load and reserve requirements in all hours across the study horizon, with offshore wind meeting demand during substantial portions of the year. Thermal resources operate at low capacity factors, providing critical reliability support during periods of low wind output, particularly during wind lulls, while contributing relatively small volumes of generation. However, managing curtailment in such a wind heavy system presents new challenges; curtailment is driven by both transmission constraints and periods of overgeneration, but can be meaningfully mitigated by increased transmission between provinces or with neighboring regions, allowing for load and

resource balancing over a larger geographic area. Importantly, local transmission investments will also be needed to mitigate stability and voltage challenges and effectively connect new resources with load centers.[3]

[3] As a zonal analysis, these local needs did not show up in this production cost modeling but were evaluated in depth in the "Preliminary Atlantic Canada Transmission Expansion Needs Analysis to Integrate Offshore Wind" report prepared by Stantec.

Introduction

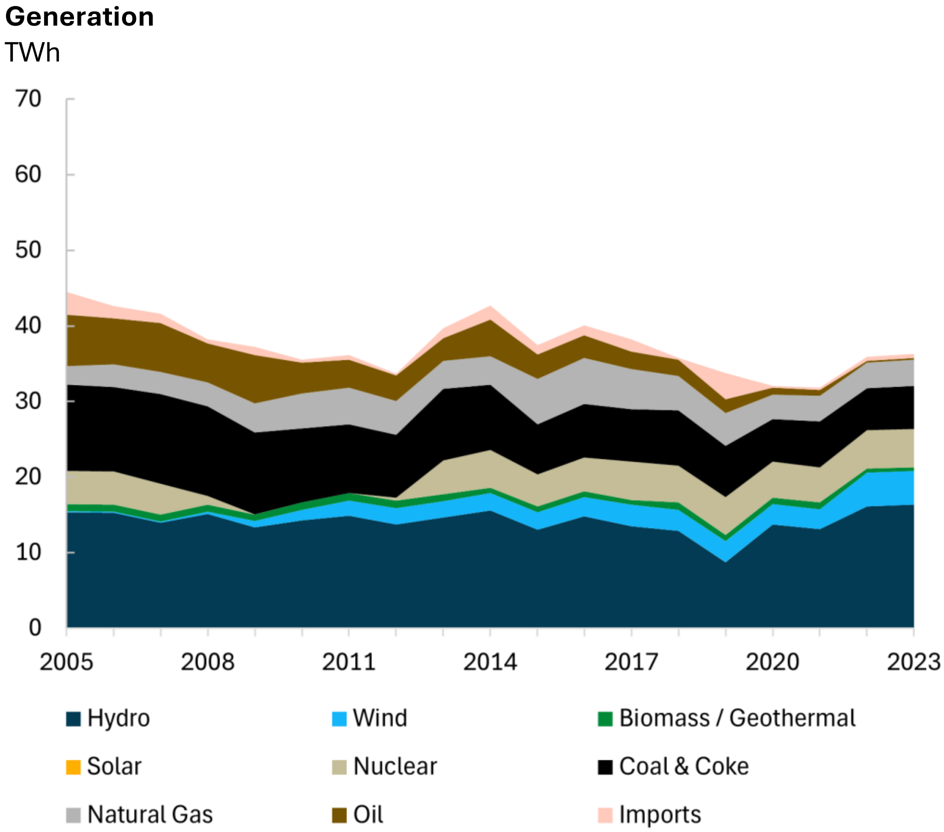
Study Context

Recognizing the risks of climate change, Canada has committed to 40-45% emissions reductions by 2030 and net-zero by 2050. This will require near complete decarbonization of key energy sectors of the economy, including power, transportation, buildings and industry. To achieve these targets, the region is pursuing a range of policies and actions to accelerate decarbonization, including carbon pricing and clean electricity regulations.[4]

The Atlantic Provinces have already made significant progress toward decarbonizing its economy, including its power sector. As shown in Figure 1 below, the Atlantic Provinces, particularly Newfoundland and Labrador, benefit from abundant hydro generation to serve load. The next largest generation sources in 2005 were coal and oil, though fossil generation has fallen in half over the last 15 years, and coal generation will be entirely phased out by 2030. This generation mix has been complemented by small but rapidly expanding onshore wind capacity, which is expected to hit at least 15 TWh region wide by 2030. The challenge in 2030 and beyond will be to replace remaining fossil generation to the extent feasible, while serving growing electrification loads and other potential new loads such as for hydrogen production.

[4] This is outlined in more detail in this study's policy short report.

Figure 1. Historical Electricity Generation Across the Atlantic Provinces [5]



To support these needs, offshore wind has the potential to be a cornerstone of regional decarbonization for the Atlantic Provinces and its neighbors, directly and indirectly facilitating sector transformation. As a scalable and abundant resource, offshore wind provides a clean energy source to offset fossil fuel baseload generation in the power sector. This clean electricity can also support electrification of other energy-consuming sectors, such as transportation and buildings, by providing the necessary clean electricity to meet increasing demands. Furthermore, offshore wind can indirectly advance progress toward net-zero by enabling the production of green hydrogen, a versatile energy carrier that can decarbonize hard-to-abate sectors like heavy industry. Unlocking the potential for offshore wind will require investments in lowering its capital-intensive development costs and building the transmission infrastructure needed to bring the clean energy supply on land and to sources of demand.

This report is part of an overall study, *Atlantic Canada Offshore Wind Integration and Transmission Study*, which assesses the potential to integrate GW-scale offshore wind into Atlantic Canada, including a detailed assessment of pathways to market, constraints, and investments needed to support the transition. The study will deliver key outputs, including:

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[5] Canada's Energy Future, 2023. Data obtained here: Macro Indicators - Canada.ca

- Highly resolved **database of wind speed profiles** for potential offshore wind development sites across Atlantic Canada;
- Assessment of **planning and operational challenges and opportunities** associated with developing the Atlantic Canadian offshore wind resource for the electricity grid; and
- Analysis of **grid infrastructure limitations and costs** necessary to allow high penetration of offshore wind electricity.

To support these overall goals, the study completed three phases of modeling and analysis[6]:

- **Phase 1: Path to Market.** This phase identified domestic, export, and hydrogen production offtake opportunities for offshore wind, leveraging a policy and resource assessment of the region to build out detailed electric sector system modeling. It also identified potential offshore wind targets and key enablers of the path to market.
- **Phase 2: Offshore Wind Resource Potential Study**. This phase characterizes offshore wind technical, locational, and economic resource potential and deployment. It also created a public database and visual graphic interface for developers, researchers, and government.
- **Phase 3: Grid Integration Study.** This phase focused on the investment and operational effort necessary to integrate three different levels of offshore wind into the Atlantic Provinces. This phase involved evaluating coordinated transmission solutions for economically improving offshore wind integration. This phase also synthesized the three phases into a Roadmap and Action Plan and a final data visualization.

Study Questions

This report addresses the following key questions:

- **Policy & Resource Assessment:** How has the region been planning for a decarbonized future? What policy representation and resource planning assumptions should be reflected in the modeled scenarios?
- **Domestic Markets:** How can offshore wind support regional load growth, given electrification and planned fossil retirements?
- **Export Markets:** How can offshore wind support export markets, particularly markets with decarbonization targets?
- **Hydrogen Markets:** How can offshore wind at higher levels grow the hydrogen industry to serve regional and potentially international demand?
- **Interprovincial Transmission:** How can expanding interprovincial transmission enable more efficient integration of offshore wind by facilitating the sharing of excess generation, reducing curtailment, and limiting the need for other new resource builds to meet demand?

[6] https://netzeroatlantic.ca/atlantic-canada-offshore-wind-grid-integration-and-transmission-study

The sections that follow summarize the modeling framework, the modeling assumptions derived from the resource assessment, the scenario design to evaluate offshore wind market opportunities, and the resulting resource portfolios and enabling factors.

Modeling Approach and Inputs

The overall goal of the study is to evaluate a range of offshore wind offtake opportunities, assess the potential long-term electric demand associated with each, and construct scenarios with offshore wind targets aligned with those expected demands. These scenarios are assessed using the PLEXOS LT electricity system capacity expansion model. This approach ensures that scenario-based offshore wind planning targets are evaluated within the context of the broader regional electricity system, simulating how offshore wind interacts with both existing and potential future grid resources. The model identifies least-cost pathways for meeting electric demand with offshore wind, alongside other supply sources, while adhering to key system constraints. This supports analysis of offshore wind's impact on system costs, reliability, and emissions. The production cost analysis builds on this foundation through more detailed hourly modeling to assess operational roles, investments, and costs.

This section provides a brief overview of the modeling toolkit for this study, key input assumptions, and the modeling scenarios developed for this study.

Modeling Framework

Capacity Expansion Model

E3 utilized Energy Exemplar's PLEXOS LT model to perform the capacity expansion modeling for this study. PLEXOS LT is an optimization model that identifies least-cost resource portfolios to meet electricity demand, subject to constraints that reflect key operational, policy, transmission, and other system constraints. When developing inputs for this study, E3 leveraged both publicly available data and client-provided data to model the existing system and future expansion resources. The following subsections outline the detailed data and input assumptions. More information about the PLEXOS LT model is available on the Energy Exemplar website (https://www.energyexemplar.com/plexos).

The PLEXOS LT model for this study included four core zones: Nova Scotia, New Brunswick, Prince-Edward Island, and the Island of Newfoundland (part of the Province of Newfoundland & Labrador). The model also included external connections to Québec, New England, and Labrador grids, to ensure sufficient representation of import and export dynamics. This high-level grid topology is illustrated in Figure 2 below. PLEXOS LT models both least-cost co-optimization of investment in new resources as well as hourly operations of select sample days that reflect a range of representative system conditions.

This study examines core capacity expansion scenarios designed to test generation and storage resource needs. Additional sensitivities layer in candidate transmission projects to test co-optimization of resource and transmission expansion to cost-effectively meet system needs.

Hourly Production Cost Model

In addition to the long-term system needs evaluation performed using the capacity expansion model, E3 also assessed hourly system operations across a subset of future years. This operational analysis leveraged PLEXOS ST (Short-Term) production cost modeling. Production cost models simulate how the power system dispatches resources hour by hour to meet electricity demand at the lowest operational cost, while respecting physical and policy constraints. These models determine which generators run, at what output levels, and when, based on demand, fuel prices, operating characteristics, transmission limits, reserves requirements, and other system constraints.

PLEXOS ST provides a detailed representation of system operations across short time horizons (hourly or sub-hourly intervals[7]). This level of detail allows us to:

+ Capture **hourly demand patterns** including seasonal variation and extreme weather events
+ Model **transmission flows and congestion**
+ Reflect **generator operational constraints** such as ramp rates, minimum run times, and startup costs
+ Represent **variability and intermittency of inverter-based resources** such as offshore wind and solar
+ Model **reserve requirements**, including how resources are committed and dispatched to maintain reliability under contingency conditions
+ Quantify production costs, emissions, curtailment, and reliability metrics[8] with **operational realism**

This operational analysis focused on three future years for detailed evaluation:

+ **2035** – the first year in which offshore wind additions show up in the model, representing the early operational impacts of policy-driven resource additions
+ **2040**[9] – an interim year in which a large sum of offshore wind is added and distributed across modeled provinces
+ **2050** – the final study year, representing the system at the point of highest installed offshore wind capacity requirements through the study horizon

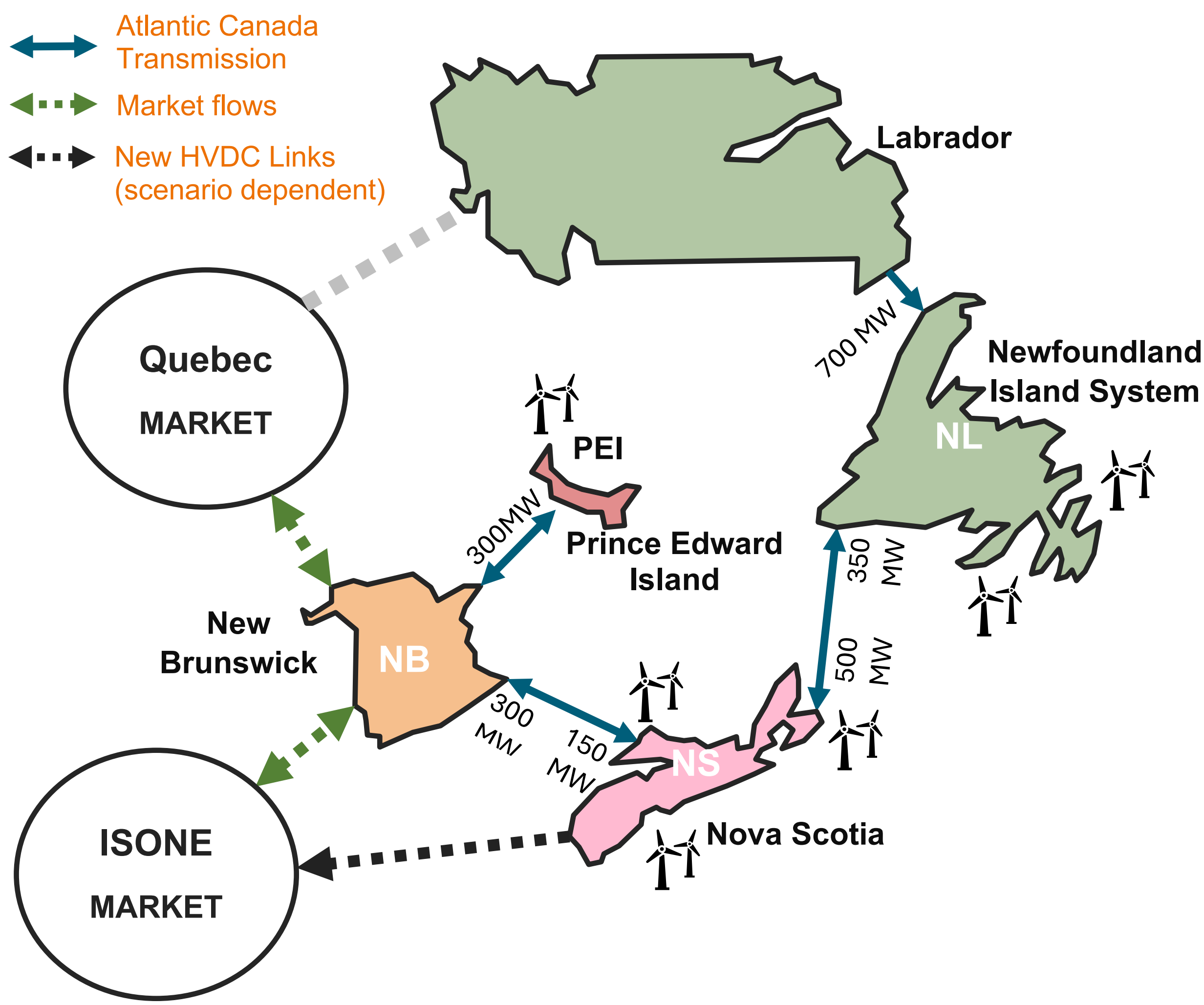
Modeling all hours within these snapshot years enabled the E3 team to evaluate how different levels of offshore wind deployment influence dispatch behavior and overall system operations under realistic conditions.

The PLEXOS ST model is built primarily on the same database developed for the capacity expansion analysis and utilizes the resource portfolios determined through that long-term modeling. However, ST requires certain additional operational inputs, particularly for thermal generating units and

[7] This operational analysis was conducted at the hourly level.
[8] Operational reliability refers to the system's ability to meet demand and required reserve margins in each modeled hour, including during stressed conditions such as wind lulls or transmission constraints.
[9] 2040 data is not included in this report or the appendix but can be found in the public database which holds all final hourly results from PLEXOS modeling efforts.

reserves requirements, in order to accurately simulate hourly commitment and dispatch decisions. These additional inputs are detailed in the Input Assumptions Section.

Figure 2. High-Level Model Load Zones and Transmission Linkages



Note: Loads and resources were modeled for Nova Scotia, New Brunswick, Prince-Edward Island, and the Island of Newfoundland. Québec and ISO-NE were reflected as market price strips. Flows from Labrador to the Newfoundland Island System were included, but electricity demand in Labrador was not provided by the utility, and thus, full load and resource representation of Labrador was not included.

Input Assumptions

The modeling in PLEXOS requires input data and assumptions to characterize the existing system and the evolution of demand, policy constraints, and investment opportunities. E3 gathered data and assumptions based on a range of available public data sources, as well as direct support from the utilities where possible, who provided data, guidance on assumptions, and feedback. The final

PLEXOS modeling also benefited from extensive offshore wind resource potential assessments and generation profile simulations conducted by Stantec and WindSim as part of Phase 2 of this study, as well as assessments of points of interconnection, interconnect costs, and onshore transmission upgrade costs conducted by Stantec. These served as valuable updates relative to the Phase 1 PLEXOS modeling and were key determinants of updated results.

Key data sources for the assessment included:

+ Data provided by the utilities in response to data requests to all utilities; utility data was provided directly by Nova Scotia Power and Maritime Electric (PEI).
+ Supplemental data from Integrated Resource Plans (IRPs) and Resource Adequacy (RA) studies for each utility.
+ Where necessary, E3 confirmed data against references on federal and provincial policy.
+ E3 also benchmarked and/or supplemented data with information based on public sources and/or previous studies developed for the Atlantic Canada region.
+ As noted above, Stantec and WindSim assessed offshore wind characteristics throughout the region, ultimately identifying 35 distinct fixed-bottom and floating offshore wind build areas distributed across Atlantic Canadian waters. Key data included annual capacity factors, hourly generation profiles, resource build potentials, distance to interconnection, spurline costs, and offshore turbine capital costs.

For certain inputs, especially candidate resource costs (other than offshore wind) and fuel prices, E3 relied on its proprietary market price forecasts, which are thoroughly vetted to ensure alignment and consistency across provinces. Across data inputs and sources, E3 leveraged expertise and feedback from this study's Project Management Committee and Technical Committee. This information is summarized in Table 1 below.

Table 1. Key Modeling Assumptions

Category	Assumption
Area & Topography	+ Each Atlantic Canadian province is represented as a zone with loads and both existing and candidate resources defined for capacity expansion analysis. + For Newfoundland & Labrador, only the Newfoundland (Island System) is modeled as a load zone, with the Labrador-Island link represented as a capacity and energy resource supplied by Muskrat Falls and Churchill Falls power purchases from Labrador. + New Brunswick is externally connected to the Québec and ISO-NE markets.
Imports & Exports	+ Firm capacity contract obligations (Table 2) are represented from Newfoundland to Nova Scotia (Nova Scotia Block), New Brunswick to Prince Edward Island, and New Brunswick to Northern Maine. + Imports from Québec to New Brunswick are limited to historical import levels. + Imports and exports between New Brunswick and ISO-NE are flexible in the model and influenced by ISO-NE market prices (E3's Market Price Forecast).
Hydroelectric Resources	+ Significant hydroelectric capacity in the Atlantic Provinces contributes to the region's load.

	+ Hourly hydroelectric operations are constrained by a requirement to hit a predetermined total daily output called a daily energy budget. Daily energy budgets vary by month and are highest in late winter and spring, when snowmelt and rainfall are peaking, and lowest in summer and fall.
Electricity Demand	+ Annual and peak load forecasts (Figure 3 and Figure 4) - consistent with utility planning and generally aligned with scenarios that achieve economy-wide net-zero goals. + Electrification levels based on utility planning assumptions in IRPs/RA studies; pulled scenarios as aligned with net-zero as were publicly available. + Given no utility data provided, additional electrification components of annual load forecasts for NB and NL were estimated from public sources.
Carbon Emissions Policy	+ Carbon price (Output-based pricing system) for electricity generation increases from $50/tonne in 2022 to $170 CAD/tonne by 2030. + Generator-specific emissions standards for OBPS used based on fuel type consumed and whether a generator is existing or new. The federal standards are adjusted in New Brunswick and Nova Scotia given legislated provincial-specific OBPS standards. + Potential future clean electricity regulations, which were not released at the time of this study, were modeled as a maximum annual CO2e emission is 100g/kWh starting in 2035 and enforced for each province individually
Resource Adequacy	+ A Planning Reserve Margin (PRM) required to achieve a reliability standard of 1-day-in-10-year is defined in "UCAP" terms for each province.[10] + Renewable and storage resources' contribution to system reliability is based on their effective load carrying capability (ELCC). Offshore and Onshore Wind contribute to the capacity requirements on separate ELCC curves that are adjusted to reflect average performance during critical hours and interactive effects. + Non-renewable resources contribution to system reliability is based on their seasonal ratings as well as their expected force outage rates. + New Brunswick firm capacity requirements include obligation to serve PEI as well as Northern Maine. + The Nova Scotia Block contract through the Maritime Link contributes to the firm capacity requirement in Nova Scotia, with a matching offset in the firm capacity value the Labrador-Island Link provides to the Newfoundland Island System. + The Labrador-Island Link firm capacity value is also affected by its potential outages in alignment with publicly available data.
Existing and Planned Resources	+ Existing resources and their operational characteristics are based on publicly available and utility-provided data, as well as Energy Exemplar (PLEXOS owner) database. + Planned resource additions before 2030 are modeled as fixed builds.

[10] The study recognizes that Newfoundland and Labrador uses 2.8 loss-of-load hours as its target, but adjusted given the need for the model to use the same target across provinces. This simplification is not expected to materially affect any results.

	+ Announced planned unit retirements or conversions are modeled as fixed, with other resources later allowed to economically retire as well.
Candidate Resources & Costs	+ Candidate resource potentials and other attributes are based on publicly available data from the utilities and data provided by them. + Candidate resource costs, performance, and financing assumptions based on cost projections derived from National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) and include interconnection costs. + Renewable generation profiles come from data provided by the utilities as well as simulated from NREL. + Candidate transmission carrying capacities and costs are based on proposed projects within the Atlantic Canada region.
Transmission Headroom[11] & Costs	+ Assumes system headroom for new candidate resources to be 860 MW in New Brunswick, 500 MW in Nova Scotia, and 500 MW in Newfoundland and Labrador. + Once resource additions exceed those amounts, incremental builds incur additional transmission delivery fees, modeled as a $300/kW deliverability adder.[12]
Onshore and Offshore wind	+ Offshore wind potentials, profiles, and capacity factors are informed by Stantec analysis and technical stakeholder feedback + Offshore wind capital costs and interconnection costs were also informed by AACE Class 5 cost estimate analysis conducted by Stantec as part of their Phase 2 Actual Deployment Potential report. + Transmission deliverability cost adders implied for new wind resources based on data provided by the utilities. + Onshore and offshore wind integration requirements for capacity expansion are modeled based on an assumed $2/MWh charge converted for each resource to a fixed annual O&M charge based on its expected annual generation. Representing this cost as fixed rather than as a variable $/MWh charge avoids distorting dispatch outcomes while still capturing the system-level integration costs associated with variable renewable resources
Fuel Costs	+ Fuel price forecasts are based on E3's in-house modeling combining short-term and long-term fuel price forecasts in the region, and the Energy Information Association's Annual Energy Outlook (AEO)[13] in the long term. + Natural gas fuel prices include representation of high increases in winter months when LNG imports in the Northeast are often on the margin.
Hydrogen Loads	+ An estimate of feasible hydrogen demand was developed based on considering both domestic consumption as well as export opportunities, from E3

[11] Transmission headroom refers to the unused capacity on the electricity transmission system that can accommodate additional power flows without overloading the grid.

[12] Deliverability adder costs were further evaluated by Stantec as part of the Phase 3 "Preliminary Atlantic Canada Transmission Expansion Needs Analysis to Integrate Offshore Wind" assessment. This work found a range of average deliverability upgrade costs across the scenarios evaluated and indicated the $300/kW modeled value was squarely within this expected range, validating this Phase 1 input assumption.

[13] https://www.eia.gov/outlooks/aeo/

	PATHWAYS model, as described below and in Appendix B Figure 6. That said, the study is agnostic as to where hydrogen produced is used and focuses instead on a range of potential hydrogen production levels and the implication for offshore wind needs. + Hydrogen electrolyzer load was modeled with explicit operational flexibility to reflect its ability to respond to system conditions and market signals. Rather than representing electrolyzer demand as fully fixed, the model allows load to vary between 75% and 100% of its nominal load factor while maintaining the annual energy targets established. To implement this, hydrogen demand was represented as a flat load, with a co-located battery resource that could emulate flexible operation. When the battery charges, it represents periods where electrolyzer load increases above the baseline (e.g., in response to low-cost renewable generation), and when it discharges, it represents reduced load during higher-cost or low-renewable-output periods. The battery was sized with sufficient duration to enable sustained response during offshore wind lulls, including periods of very low or zero generation, which are critical conditions in high offshore wind penetration scenarios. This approach allows the model to capture how hydrogen production can dynamically align with renewable availability and market conditions, improving overall system efficiency and reducing curtailment.

Regional Load Forecast

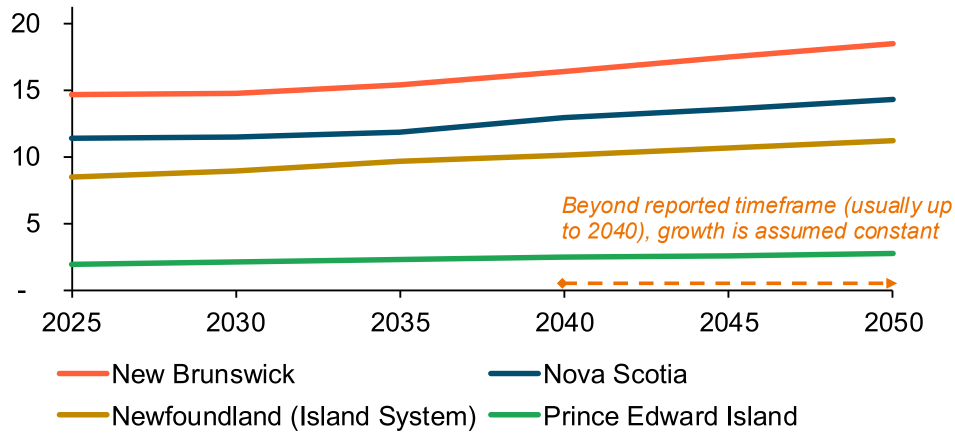
The study leverages province-level load forecasts to reflect the evolution of electricity demands over time, based on input from the utilities and public planning documents in cases where utilities did not provide data directly[14]. To the extent feasible, E3 selected load forecasts that reflect energy demand growth in the Atlantic Provinces in alignment with economy-wide net-zero goals. The pace and electrification strategy varies to some extent by province. To translate annual load forecasts into hourly demands, E3 leveraged utility input and public reports where possible, relied on its robust in-house load shaping toolkit to model the evolution of hourly load profiles when needed, including layering on load profiles for electric vehicles and heat pumps on top of historical system load profiles to create hourly shapes consistent with net-zero. We note, however, that potential but today uncertain new large loads associated with potential new data centers were not layered into this analysis.

The primary impact of building electrification in the region is through space heating loads, with gas furnaces and electric resistance heating being replaced by a range of heat pump technologies. This means some demand previously served by natural gas shifts to the electric sector, increasing annual and peak demand. Meanwhile, the replacement of electric resistance heating with more efficient heat pumps reduces annual demand on the grid and, especially in the case of hybrid heat pumps, reduces peak demand. Overall, annual and peak energy demand is expected to increase in all provinces, especially in the winter months.

[14] This includes New Brunswick Power's 2023 IRP and NL Hydro's 2024 Resource Adequacy study.

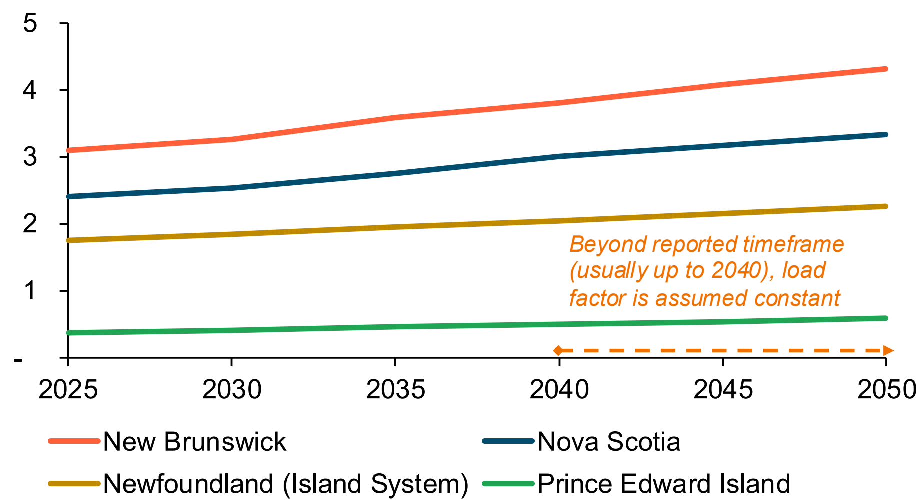
Transport electrification has a significant impact on annual and peak demand as well, with a higher impact on winter months given electric vehicle charging and battery efficiency fall significantly at low temperatures. The resulting annual energy demand and winter peaks for all provinces increase considerably, which drives the energy and capacity need on the grid as the system evolves. The annual loads and peak loads are shown in Figure 3 and Figure 4 below.

Figure 3. Annual Energy Demand (TWh)



Notes: The load forecasts are based on information provided directly by the utilities (Maritime Electric and NSP) and where not provided, from public sources (NB Power 2023 IRP and NL Hydro 2024 RA Study). These forecasts include assumptions related to demand-side management (DSM). We note that any BTM solar generation is not netted from load and modeled as a supply side resource. These figures are prior to layering on additional hydrogen loads, and do not assume new data center load materializes.

Figure 4. Annual Peak Demand (GW)



Notes: The load forecasts are based on information provided directly by the utilities (Maritime Electric and NSP) and where not provided, from public sources (NB Power 2023 IRP and NL Hydro 2024 RA Study). These forecasts include assumptions related to demand-side management (DSM). We note that any BTM solar generation is not netted from load and modeled as a supply side resource. These figures are prior to layering on additional hydrogen loads, and do not assume new data center load materializes.

Import and Export Assumptions

The study models the loads and resources of the four provinces, with a key focus on capturing the evolving dynamics between them to assess the implications of integrating high levels of offshore wind. Imports and exports within the Atlantic Provinces are primarily modeled as flexible and economically driven to capture the evolving dynamics of the system as resource portfolios and demand evolves in different locations – leading to different flows than observed historically and today. However, firm contracts are still represented between New Brunswick and PEI and between Newfoundland & Labrador and Nova Scotia (Nova Scotia Block). These contracts are not modeled as "must-take" fixed flows on an hourly energy basis within the representative periods in capacity expansion but are accounted for in the planning reserve margin and firm capacity requirements in each zone.[15]

The island system of Newfoundland, part of the province of Newfoundland & Labrador, is modeled as its own zone separate from the Labrador northern part of the same province. This representation is aligned with how planning and reliability analysis was performed in the NL Hydro 2024 Resource Adequacy study, given this was the primary available source of data, and enables the explicit modeling of the Labrador-Island Link (LIL) as a key transmission resource connecting the island system Newfoundland to the extensive hydro generation in Labrador. The Labrador-Island Link is modeled as an energy source as well as a capacity resource for Newfoundland and the Nova Scotia Block – after accounting for its expected outage rates. This allows the model to represent how the Labrador-Island Link is a constraint which makes Newfoundland a distinctive load and resource zone within the province, despite the large amounts of hydro energy available in Labrador from Muskrat Falls and Churchill Falls contracts.

Table 2. Internal Market Interfaces Assumptions Summary

Interfaces within Atlantic Canada	Transmission Nameplate Capacity	Firm Capacity
New Brunswick – Prince Edward Island	300 MW bi-directional	300 MW from NB to PEI
New Brunswick – Nova Scotia	150 MW from NB to NS, 300 MW from NS to NB	None
Newfoundland – Nova Scotia	500 MW bi-directional	Nova Scotia Block, 153 MW
Labrador-Island Link	700 MW from Labrador to Newfoundland[16]	Firm capacity was derated based on line ratings reported in 2024 RA study, given forced outages

[15] For example, the New Brunswick reliability requirement is increased by the 300 MW it is obligated to serve as firm to Prince Edward Island, while the latter's reliability requirement is be reduced by the same 300 MW.

[16] Study management committee members indicated that this transmission capacity may increase in the future to 900 MW, pending ongoing testing.

In this study, the Atlantic Provinces have three main interfaces with external markets: the New Brunswick and ISO New England interface (NB-ISO-NE), the Hydro Québec and New Brunswick Interface (HQ-NB), and, in select scenarios, a Nova Scotia and ISO New England interface (NS-ISO-NE) designed to enable Offshore wind export opportunities. The first two have flow components established based on 2023 historically observed month-hour average flows.[17] NB-ISO-NE flows are fixed to the observed export flow pattern from New Brunswick to ISO New England. HQ-NB flows are more flexible. HQ-NB flows are enabled to import to New Brunswick at hourly quantities less than or equal to the observed import pattern from Hydro Québec to New Brunswick but can also export as much as 1,000 MW (based on previous E3 work) in the reverse direction. The flexibility in HQ-NB flows is modeled to enable deviations from historical New Brunswick imports to allow offshore wind energy an opportunity to export when economically viable rather than be curtailed.

The MW transfer capacity of the NS-ISO-NE intertie is designed to expand to match the installed offshore wind capacity built in export cases. NS-ISO-NE is modeled as an export-only interface with no imports enabled from ISO New England to Nova Scotia. All exports are valued based on a price forecast for the Boston load zone, the largest load zone within ISO-NE with the ability to offtake the scale of exports modeled in this study. The price forecast used in the model was produced in a separate hourly price forecasting exercise that reflects changes in loads and resource mix in ISO-NE through the 2050 model horizon. It is important to note that ISO-NE loads and resources were not explicitly modeled in this study. Accordingly, it is implicitly assumed that, given appropriate price signals, Nova Scotia could export up to the transmission line limit to ISO-NE. Additional information related to assumptions is available in Appendix B, including historical average flows.

Additional Inputs for Interprovincial Transmission Expansion Assessment

This study also explored supplemental scenarios that enable the model to co-optimize interprovincial transmission investment with generation and battery expansion. These transmission expansion scenarios investigate the interactions between interprovincial interties and economically selected offshore wind resources. Input assumptions shown in Table 3 are based on reference projects that have been proposed in the region. These include transfer capabilities, project costs, and first available build year. One candidate transmission line was defined for each existing interprovincial transmission line, with each candidate providing bidirectional flow capability and becoming available for the model to build beginning in 2035.

Table 3. Candidate Transmission Resources Inputs

Interfaces within Atlantic Canada	Incremental Transmission Nameplate Capacity	Cost, (CAD)	First Available Year	Reference Project
Nova Scotia <> Newfoundland & Labrador	1,250 MW	$3,163/kW	2035	Hypothetical New HVDC Link (±500kV)

[17] https://tso.nbpower.com/Public/en/system_information_archive.aspx

Nova Scotia <> New Brunswick	860 MW	$930/kW	2035	Reliability Tie (New 345kv)
New Brunswick <> Prince Edward Island	560 MW	$446/kW	2035	Capable Replacement and Voltage Uprate

Hydrogen Load Forecast

In decarbonization planning across the globe, hydrogen has emerged as a potential solution for hard-to-decarbonize applications, including heavy industry and refining, aviation, and shipping, as well as a source of power generation during challenging conditions. A key strategy to produce zero-carbon hydrogen is to use electrolysis powered by renewable electricity.[18] Given the high capacity factor of offshore wind, there has been significant interest in using offshore wind to power electrolysis in the Atlantic Provinces, which would create significant new electricity demand. As shown in Appendix Section B.4, there are at least a dozen known projects at various stages of planning across the Atlantic Provinces today, with most focused on exports using onshore wind in the near-term.

While it is difficult to predict the most probable applications for the hydrogen demands, and, in particular, the balance of hydrogen for domestic consumption versus hydrogen for export markets, E3 assessed possible hydrogen demands to inform a range of potential electrolysis loads that offshore wind might support. The assessment of potential demands should not be interpreted as the definitive end uses for the hydrogen produced: rather, the goal is to assess a range of potential hydrogen loads served by offshore wind, and this approach allows us to benchmark this range to end uses that we can measure.

First, as a proxy for a "base" level of hydrogen production, E3 estimated the amount of domestic hydrogen demand that could be utilized regionally, agnostic to low-carbon hydrogen power source, as part of an economy-wide net-zero future, roughly aligned with the load forecasts. E3 leveraged its E3 Atlantic Provinces PATHWAYS model, which includes representation of economy-wide energy demand by end use and province.[19] The model includes detailed accounting of residential, commercial, industrial, and transportation equipment lifetimes, benchmarked to public Canadian government databases and utility IRPs. This enables representation of the replacement of equipment and energy demands with different decarbonized strategies, including hydrogen, over time.

Hydrogen was assumed to serve key hard-to-decarbonize end uses in the economy, based both on E3's experience leading decarbonization and hydrogen modeling and research for major jurisdictions across North America; an updated review of the latest research and projects; and

[18] Electrolysis involves breaking water into hydrogen and oxygen using an electrical current.
[19] PATHWAYS is an economy-wide energy and greenhouse gas scenario planning model developed by E3 to create decarbonization policy scenarios across multiple economic sectors. It is a long-horizon, infrastructure-based stock rollover model, with detailed representation of the buildings, industry, transportation, and electricity sectors. The E3 PATHWAYS model utilized to estimate hydrogen demands was initially developed as part of the 2020 Atlantic Clean Provinces study. More information about the tool is available here: PATHWAYS - E3. More information on inputs is available in the ACP Study.

discussions with stakeholders and regional hydrogen experts. Based on this, E3 determined that the critical end use cases for hydrogen in the Atlantic Provinces could be:

- high-temperature industrial heating,
- heavy-duty vehicles,
- aviation,
- and small amounts of residential/commercial space and water heating.

Hydrogen could also directly replace thermal generation in power plants, if those plants are converted to burn hydrogen or new hydrogen-burning combustion CTs are built. We estimated the amount of hydrogen production that would be consistent with replacing the highest levels of thermal generation we see in a range of future utility planning scenarios.[20] If the regional power sector doesn't need or leverage this hydrogen production, we anticipate that it would additionally serve other end uses, like export markets. Hydrogen could also replace other end uses, like oil and gas refining, green steel, and maritime shipping; however, given significant uncertainty regarding the future of those industries (former) and the lack of sector specific data (latter), we did not directly include these estimates in our hydrogen production forecast. That said, it is very possible that these other end uses could replace some of the hydrogen offtake from these other end uses, and we emphasize that the goal was to estimate a feasible range of hydrogen production levels, and then evaluate the role that offshore wind could play in meeting those demands and the implications for overall grid build-out.

Export opportunities offer a potentially much larger but more uncertain offtake opportunity for hydrogen. On one hand, E3 analysis and certain reports on the global hydrogen outlook[21] find that hydrogen production in the Atlantic Provinces using offshore wind as the clean power source, faces high investment costs and is today expensive relative to the most cost competitive producers. However, significant momentum and interest in Atlantic Province-based hydrogen production, specifically as potential exports to European markets (i.e. the $300 million Canada-Germany Hydrogen Alliance agreement), could help to reduce costs and spur new investment.

Given the uncertainty related to exports, E3 developed two modeling scenarios for hydrogen production (to be served by onshore and offshore wind):

+ **"Base Hydrogen" scenario**, which is based on levels of hydrogen production consistent with domestic consumption and/or more limited exports.
+ **"High Hydrogen" scenario**, which assumes expanded export opportunities for the Atlantic Provinces based upon current plans for hydrogen projects (with some attrition assumed[22])

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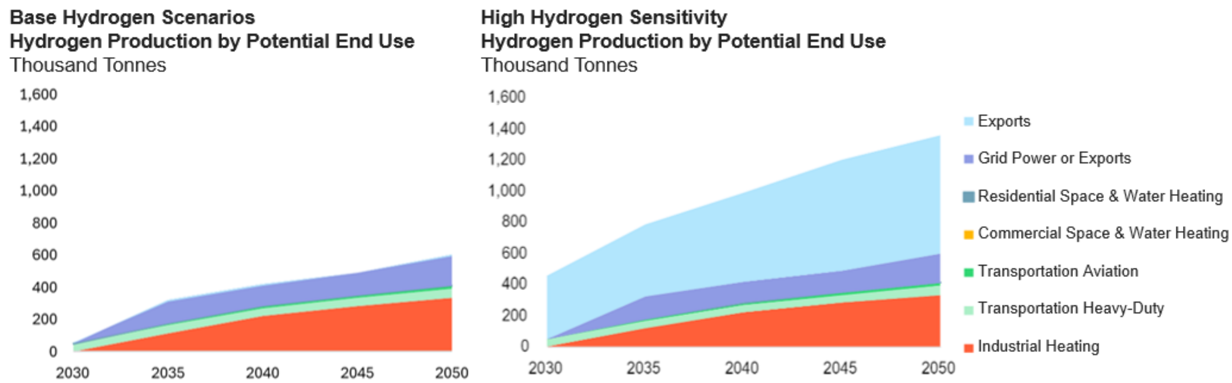
[20] We note that we did not investigate the economics of burning hydrogen in the power sector in detail, given the focus on offshore wind.

[21] Global Energy Perspective 2023: Hydrogen outlook | McKinsey

[22] This attrition accounts for the assumption that some fraction of currently proposed hydrogen development projects may not achieve operations or fulfill the required criteria for final investment.

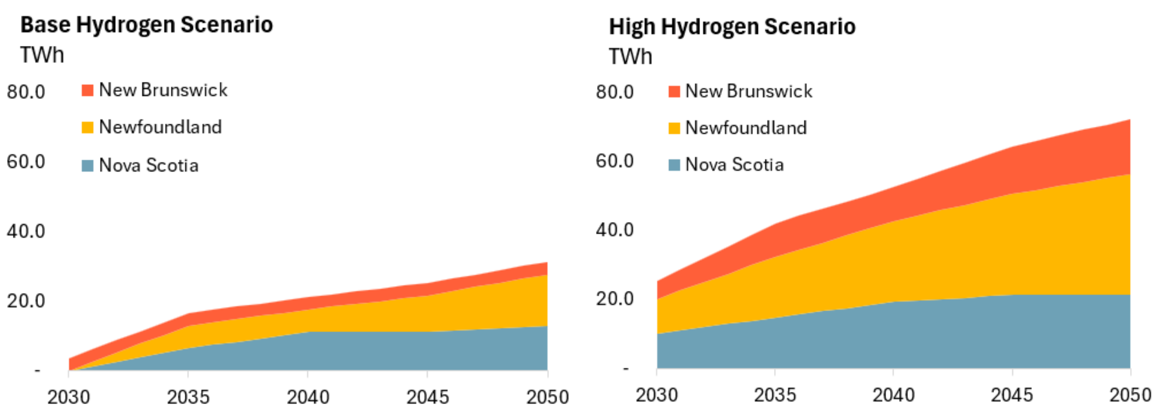
The cumulative hydrogen production for these two scenarios is shown in Figure 5 below. Note that E3 discusses forecasts in terms of tons of hydrogen as a unit of comparison, but in the real world, the end use product might be derivatives of hydrogen like ammonia or electrofuels.

Figure 5. Atlantic Province Hydrogen Demand Projections



The region-wide hydrogen load is allocated to provinces based on onshore and offshore wind potential to support electrolysis, as well as review of existing projects and expert input, as shown in Figure 6 below. The hourly hydrogen load shapes are provided in Appendix B.

Figure 6. Atlantic Province Electrolyzer Load Forecast[23]



Offshore Wind Cost and Potential Assumptions

Offshore wind presents an opportunity to significantly expand clean electricity generation in the Atlantic Provinces, building a new industry that could help drive economic development, and supply large volumes of zero-carbon energy both locally and to neighboring regions. To evaluate the

[23] Hydrogen load is modeled as interruptible, under the assumption that load would be able to ramp down in the case of a loss-of-load risk or potential event.

economics and integration challenges of offshore wind, E3 leveraged Stantec's Phase 2 analysis of offshore wind modeling characteristics and resource costs.

Across all four Atlantic provinces, offshore wind resource areas were screened based on geospatial constraints including water depth, distance to shore, environmental exclusions, and proximity to transmission interconnection points and then grouped into representative development clusters. In Nova Scotia, these clusters were designed to align with provincially identified Wind Energy Areas, while in other provinces they reflect analogous groupings of high-quality and developable resource areas. In total, 24 distinct offshore wind clusters were defined across the region, representing a mix of fixed-bottom and floating technologies. For each cluster, high-resolution wind data was used to simulate hourly generation profiles, capturing seasonal and diurnal variability in output. These profiles, combined with assumptions on turbine technology and layout, were used to estimate cluster-level resource potential, capacity factors, and total energy production for use in system modeling. A more detailed description of this analysis and the resulting cluster characteristics can be found in the report titled Actual Deployment Potential of Atlantic Canada Offshore Wind.[24]

Offshore wind capital costs are based on AACE Class 5 cost estimates developed by Stantec as part of the Phase 2 analysis and incorporate province-specific estimates based on factors such as land, labor, and tax costs. Fixed offshore wind resources were modeled at higher granularity: resources were classified into nine groups based on location, capacity factor, and distance to point of interconnection (POI). These groups were used to calculate site-specific spurline transmission costs required to deliver offshore wind energy to the POI.

Spurline transmission costs were developed using market-based cost data and disaggregated into key subcomponents, including offshore cables, onshore cables, offshore AC substations, onshore AC substations, offshore converter stations, and onshore converter stations. Cost assumptions were differentiated across four configurations: fixed-bottom platforms with HVAC transmission, floating platforms with HVAC transmission, fixed-bottom platforms with HVDC transmission, and floating platforms with HVDC transmission. Offshore cable costs were assumed to scale with distance to POI, while other components were treated as fixed per project.

Projects were assumed to utilize HVAC transmission for distances of 100 km or less to shore, and HVDC transmission for longer distances, reflecting typical industry design thresholds. These cost assumptions are summarized in Table 4 for a representative 1 GW installation 100 km from its point of interconnection.

[24] https://netzeroatlantic.s3.ca-central-1.amazonaws.com/files/2026-01/phase_2_report_actual_deployment_potential_atlantic_canada_offshore_wind_260129.pdf

Table 4. Offshore Wind Spurline Cost Components for Representative 1GW Installation 100 km from Point of Interconnection[25]

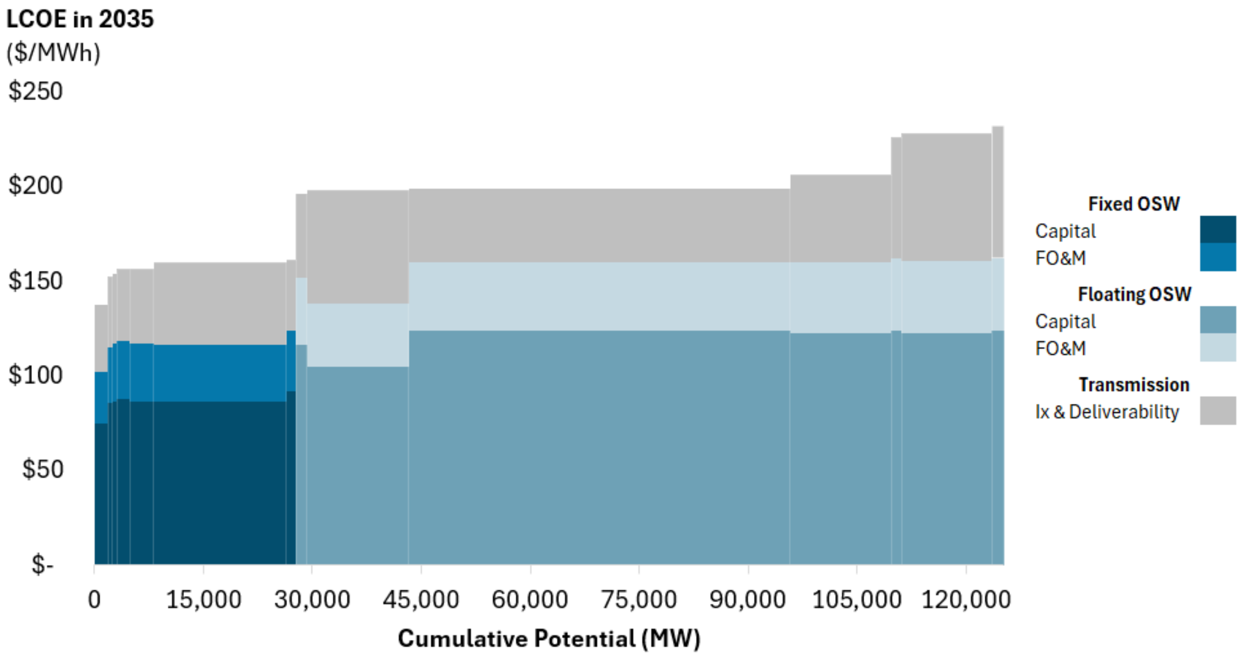
Cost Component	Fixed platform, AC transmission to shore (Million CAD)	Floating platform, AC transmission to shore (Million CAD)	Fixed platform, HVDC to shore (Million CAD)	Floating platform, HVDC to shore (Million CAD)
Offshore cables	$1,351	$1,622	$384	$461
Onshore cables	$182	$182	$122	$122
Offshore AC substation	$610	$731	$0	$0
Onshore AC substation	$144	$144	$0	$0
Offshore converter station	$0	$0	$1,384	$2,767
Onshore converter station	$0	$0	$414	$414
TOTAL	**$2,287**	**$2,679**	**$2,304**	**$3,765**

Figure 7 below illustrates all-in investment costs (capital costs and fixed O&M) for each candidate offshore wind resource in our model in 2035[26], sorted from lowest to highest cost including interconnection and deliverability costs. The width of each bar reflects the total buildable potential (in MW) at a given all-in LCOE. Costs are broken into levelized capital costs, fixed operations & maintenance, and transmission, with the transmission costs comprising both interconnection and onshore deliverability upgrade costs as discussed above. LCOE data of course is a function of both the cost inputs and the estimated production of a given resource. The detailed simulation performed by Stantec (in collaboration with WindSim) in Phase 2 produced full production profiles for each offshore cluster site. After accounting losses, these result in average annual capacity factors of between 52% and 58% across the region.

[25] All offshore wind and associated transmission cost inputs were developed by Stantec as part of the Phase 2 Actual Deployment Potential analysis.

[26] Note while we do incorporate the Canadian Investment Tax Credit in our resource cost modeling, by 2035 that credit has fully phased out under current law, and so it does not impact cost projections in this figure.

Figure 7. Offshore Wind Supply Curve, Levelized Cost of Energy in 2035 ($2022 CAD/MWh)[27]



Note: The figure shows the total cumulative resource technical potential considered in this phase of work. The LCOE values reported above are estimated prior to layering on any curtailment of resources.

Additional Inputs for Production Cost Analysis

As noted previously, the PLEXOS ST model is built primarily on the same database developed for the capacity expansion analysis and utilizes the resource portfolios determined through that long-term modeling. However, PLEXOS ST requires certain additional operational inputs, particularly for thermal generating units and reserves requirements, in order to accurately simulate hourly commitment and dispatch decisions.

Thermal Operational Characteristics

Operational characteristics for existing and known planned resources were derived from data requests sent to the utilities whose service territories are represented in this study. For existing or planned units where data were not available, we applied average performance characteristics by technology type and province calculated using available data from other similar generators in the model. For generic new-build thermal units selected as part of the capacity expansion optimization,

[27] All offshore wind capital costs, fixed operation and maintenance (FO&M) costs, and transmission costs were developed by Stantec as part of their Phase 2 Actual Deployment Potential analysis. These input costs were used to inform the LCOE data shown in this chart.

assumptions were developed using the National Lab of the Rockies (NLR's) Annual Technology Baseline (ATB), supplemented by E3's standard modeling assumptions. All operating assumptions were reviewed and aligned in consultation with the Project Management Committee and Technical Committee (PMC-TC). These assumptions include unit size, must-run status, minimum stable level, heat rate, minimum up and down times, start-up and shutdown costs, and ramp rates. These assumptions are summarized in the tables below.

Table 5. Thermal Generator Operating Characteristics

Generation Technology	Fuel	Unit Size, MW Min-Max (New)	Must-run
Nuclear	Uranium	150-663 (250)	Yes
Gas Combined Cycle Gas Turbine (CCGT)	NG	81-263 (150)	No
Gas or Dual-fuel Combustion Turbine (CT)	FO/NG	33-150 (100)	No
Dual-fuel Steam Turbine (ST)	FO/NG	12-350	Some
Oil Internal Combustion Engine (ICE)	FO	1-29	No
Coal Steam Turbine (ST)	Coal/FO	150-467	No
Other Steam Turbine (ST)	Biomass	1-375	Some

Table 6. Thermal Generator Operating Characteristics (Continued)

Generation Technology	Min. Stable Level Min-Max (New)	Heat Rate Btu/kWh Min-Max (New)	Min Up/Down Time hours	Start/Shutdown Costs $/cycle Min-Max (New)	Ramp Time
Nuclear	90% (90%)	10,000 – 10,700 (9,200)	*N/A*	*N/A*	*N/A*
Gas CCGT	30-45% (30%)	6,500 – 8,000 (6,400)	8/6	10,000 – 19,000 (7,500)	1 hours
Gas or Dual-fuel CT	40-60% (40%)	10,900 – 13,500 (9,500)	*N/A*	3,800 – 10,800 (5,000)	10 min
Dual-fuel ST	35-45%	10,200 – 12,500	12/12	48,000 – 91,400	2 hours
Oil IC	*N/A*	11,000 – 12,000	*N/A*	*N/A*	5 min
Coal ST	37-58%	10,000 – 10,700	12/12	78,300 – 263,000	2 hours
Biomass	40%	10,000 – 18,000	48/12	1,500 – 52,223	2 hours

Reserve Modeling Framework

In addition to energy dispatch, the ST model explicitly represents operating reserves to maintain reliability under uncertainty and contingency conditions. We modeled two primary reserve products: renewables balancing reserves and spinning reserves. Reserve requirements are calculated at the provincial level; however, reserve sharing across provinces is enabled where sufficient transmission headroom remains after energy dispatch, allowing interties to contribute to meeting reserve obligations when physically feasible.

Renewables balancing reserves are designed to compensate for wind and solar generation intermittency and ensure reliable operations even at higher levels of renewable penetration. The formulation and parameterization of this reserve product are based on the 2020 NREL Regional Energy Deployment System Model [28] and were previously applied in the publicly available decarbonization study E3 conducted on behalf of New Brunswick Power in 2023. The properties of this reserve product are as follows:

+ Reserve quantity = 3.5% of load + 14.5% of wind generation + 4% of installed solar capacity (during solar-generating hours)
+ Maximum response time = 30 minutes
+ Minimum delivery duration (to constrain battery contribution to reserves) = 1 hour

Spinning reserves are modeled to respond more rapidly to unforeseen power imbalances and stability events. The properties of the spinning reserve product include:

+ Reserve quantity = The total quantity of spinning reserves across all provinces is based on the largest single contingency, Pt. Lepreau, at 660 MW. The province-specific reserve provision for Nova Scotia was provided by the client. For the other provinces, reserves were allocated based on each province's share of the total combined load and analyst insight.
+ Maximum response time = 10 minutes
+ Minimum delivery duration (to constrain battery contribution to reserves) = 1 hour

On the guidance of Technical Committee members, an additional supplemental spinning reserve constraint was modeled in Nova Scotia requiring at least one thermal unit to be online and generating and the Reliability Tie to Newfoundland & Labrador to provide reserves support.[29] In Nova Scotia, the spinning reserve requirement is therefore modeled as the greater of (1) the standard reserve requirement defined above or (2) the quantity of reserves that can be provided by one online thermal unit and the Reliability Tie.

A summary table of reserve assumptions are included below.

Table 7. Reserves Model Parameters

Reserve Product	Parameter	Nova Scotia	New Brunswick	Prince Edward Island	Newfoundland & Labrador
Renewables Balancing Reserves	Quantity of Reserves	3.5% of load + 14.5% of wind generation + 4% of solar capacity	3.5% of load + 14.5% of wind generation + 4% of solar capacity	3.5% of load + 14.5% of wind generation + 4% of solar capacity	3.5% of load + 14.5% of wind generation + 4% of solar capacity
	Required Response Time	30 minutes	30 minutes	30 minutes	30 minutes
	Duration of Reserves	1 hour	1 hour	1 hour	1 hour

[28] Regional Energy Deployment System (ReEDS) Model Documentation: Version 2020, NREL: https://docs.nrel.gov/docs/fy21osti/78195.pdf

[29] Only thermal units with installed capacity of at least 50 MW were eligible to contribute to this constraint. Units between 50 MW and 100 MW were treated as providing partial contribution (0.5 units), such that two units in this size range were required to satisfy the constraint. Units with capacity greater than 100 MW were considered sufficient to meet the requirement individually.

Spinning Reserves	Quantity of Reserves[30]	168 MW	250 MW	47.2 MW	194.8 MW
	Required Response Time	10 minutes	10 minutes	10 minutes	10 minutes
	Duration of Reserves	1 hour	1 hour	1 hour	1 hour
Additional Constraint	Quantity of Reserves	Minimum of 1 thermal unit online	N/A	N/A	N/A

Scenario Design

To assess the implications of different offshore wind market opportunities, this study analyzes several scenarios that vary the level and timing of offshore wind build-out, aligned with meeting different market opportunity needs. A description of these scenarios is provided in Figure 8 below. These scenarios consider increasingly expansive offshore wind offtake opportunities, aligned with the levels of demand assessed as part of the regional data aggregation described in the input development section. All scenarios are incremental to the existing onshore wind on the system.

Our scenario design approach models offshore wind as a planned build to ensure that offshore wind build levels meet the specific targets to support different offtake opportunities. Under this approach, we can evaluate the overall system grid impacts of strategic or policy-driven offshore wind targets. As a counterfactual, E3 also ran a Reference scenario, which represents a business-as-usual future with existing and planned resources through 2030, and historical market interactions. The model can economically select the least cost set of resources to meet remaining system needs.

E3 also ran sensitivities on the hydrogen scenarios that use the “high” hydrogen levels as well as the base hydrogen levels. The total GW build-outs assumed for each scenario is described in Table 8, and shown graphically in Figure 9. E3 also ran an expanded transmission sensitivity, which increases NB-NS transmission, and is shared in the Appendix.

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[30] The total quantity of spinning reserves across all provinces is based on the largest single contingency, Pt. Lepreau., at 660 MW. The province-specific reserve provision for Nova Scotia was provided by NSPI. For the other provinces, reserves were allocated based on each province’s share of the total combined load and analyst insight.

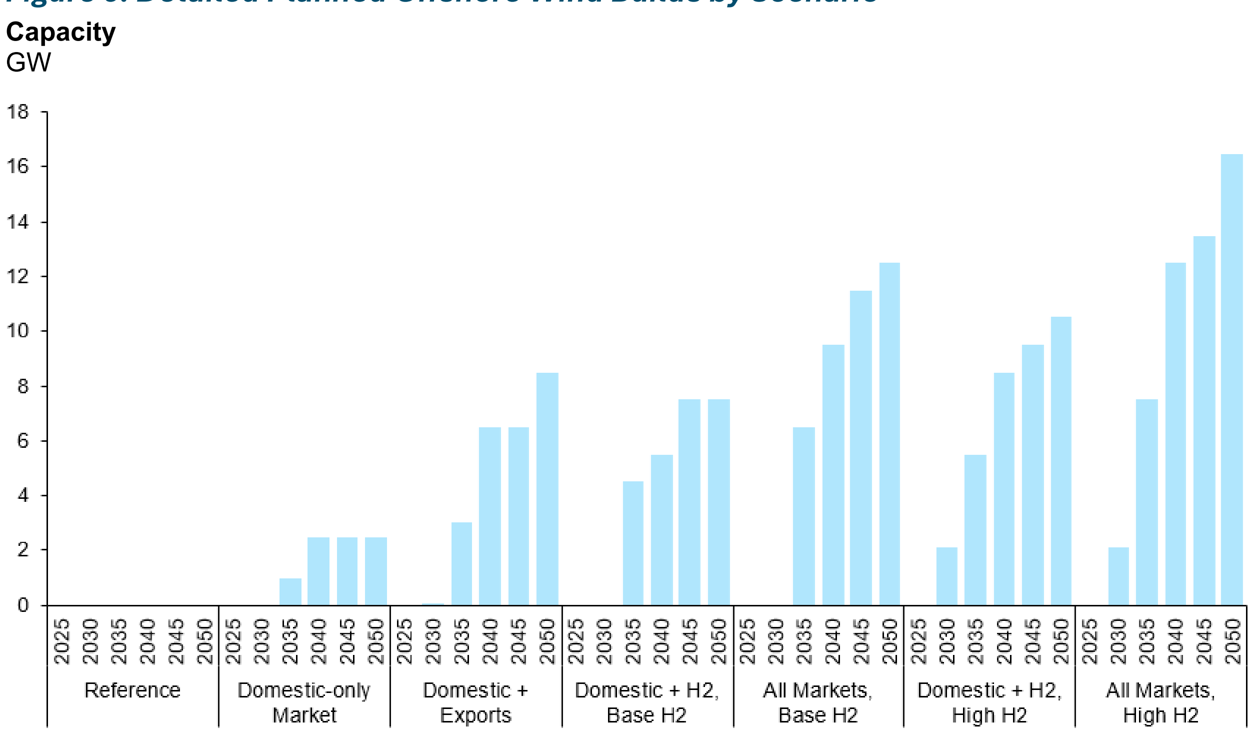
Figure 8. Future Scenarios Considered in this Study

Table 8. Scenario Offshore Wind Builds

	Offshore Wind Planned Builds (GW)				
Scenario Name & Description	**2030**	**2035**	**2040**	**2045**	**2050**
Reference Reflects "business-as-usual" conditions	-	-	-	-	-
Domestic-only Reflects offshore wind serving the Atlantic Provinces	-	1	2.5	2.5	2.5
Domestic + Exports Reflects offshore wind serving the Atlantic Provinces and export markets	-	3	6.5	6.5	8.5
Domestic + H2, Base H2 Reflects offshore wind serving the Atlantic Provinces and potential hydrogen loads	-	3	5.5	6	6.5
Domestic + H2, High H2 Reflects offshore wind serving the Atlantic Provinces and potential high hydrogen loads	2	5.5	8.5	9.5	10.5
All Markets, Base H2 Reflects offshore wind serving the Atlantic Provinces, export markets, and potential hydrogen loads	-	5	9.5	10	12.5
All Markets, High H2 Reflects offshore wind serving the Atlantic Provinces, export markets, and potential high hydrogen loads	2	7.5	12.5	13.5	16.5

Note: Scenarios may still build additional offshore wind that is optimally selected by the model. We also note that the export scenarios built both offshore wind and increasing amounts of transmission export capability to transfer this energy to external markets.

Figure 9. Detailed Planned Offshore Wind Builds by Scenario



Additional Information on Wind Builds for Hydrogen Scenarios

Current and planned hydrogen projects across the Atlantic Provinces largely focus on onshore wind today, given this resource is cheaper, high performing and well established in the region. To reflect this, E3 assumes that hydrogen loads are met with a combination of onshore and offshore wind resources. The scenarios rely more heavily on onshore wind in the near-term, and transitions to supporting new incremental projects with offshore wind in the longer term, as costs come down and the region builds experience in this resource. In these scenarios, E3 models planned builds for onshore and offshore wind to support hydrogen as indicated in Table 9 and Table 10.

Table 9. Base Hydrogen Scenario, Total Cumulative Capacity to Support Hydrogen Production* (GW)

Resource	Province	2030	2035	2040	2045	2050
Offshore Wind	Newfoundland and Labrador		1	1	1.5	2
	Nova Scotia		1	2	2	2
	Total	**0**	**2**	**3**	**3.5**	**4**
Onshore Wind	New Brunswick	1	1	1	1	1
	Newfoundland and Labrador		0.5	0.5	1	1.5
	Nova Scotia		0.5	0.5	0.5	1
	Total	**1**	**2**	**2**	**2.5**	**3.5**

* Note: This scenario assumes only a smaller portion of current potential projects reach commercial operation and connect to the regional grid. It does not account for additional projects that may be developed independently of the regional electric grid. These off-grid hydrogen projects could be significant and represent additional potential beyond what is modeled here.

Table 10. High Hydrogen Scenario, Total Cumulative Capacity to Support Hydrogen Production* (GW)

Resource	Province	2030	2035	2040	2045	2050
Offshore Wind	New Brunswick		1	1	1.5	2
	Newfoundland and Labrador	1	1.5	2	2.5	3
	Nova Scotia	1	2	3	3	3
	Total	**2**	**4.5**	**6**	**7**	**8**
Onshore Wind	New Brunswick	1.5	1.5	1.5	2	2
	Newfoundland and Labrador	1.5	3	4	5	6
	Nova Scotia	1.5	1.5	1.5	2	2
	Total	**4.5**	**6**	**7**	**9**	**10**

* Note: This scenario assumes a portion of current potential projects reach commercial operation and connect to the regional grid. It does not account for additional projects that may be developed independently of the regional electric grid. These off-grid hydrogen projects could be significant and represent additional potential beyond what is modeled here.

Results

The electric sector modeling produces electricity generation portfolios, by province, which meet projected electricity demand in each scenario, subject to the policy, operational, transmission and technological constraints described above and in Appendix B. As described in the prior section, the modeling approach is **scenario-based**: it incorporates offshore wind builds as a fixed, or planned, part of the future scenarios, illustrating the implications of buildouts on the overall system needs, costs, emissions and reliability.

In what follows, E3 describes first key results and findings from the long-term capacity expansion assessment, with focus on the electric sector resource portfolios in each scenario, the generation mix and associated emissions, the change in regional electricity flows, and the resulting costs associated with different resource futures. Next, we discuss the results of a selection of interprovincial transmission expansion sensitivities, with focus on the forecast conditions in which interprovincial transmission is economic, and how that impacts costs and resource builds. Finally, E3 details findings from the operational analysis, which utilizes the same long-term resource portfolios developed through the capacity expansion assessment and performs an hourly redispatch of those resources to inform a more detailed view of system operations. Importantly, this operational analysis looks at the same scenarios but focuses on generation dispatch during a selection of illustrative weeks in the years 2035 and 2050.

Long-Term Capacity Expansion Assessment

Electricity Resource Capacity Portfolios

The modeling produces electric sector capacity across the provinces for each year, from 2025 through 2050. In Figure 10 and Figure 11, E3 reports the total Atlantic Provinces electricity installed capacity and generation across scenarios, as well as for the Reference, which represents counterfactual conditions without a specific focus on building offshore wind.[31]

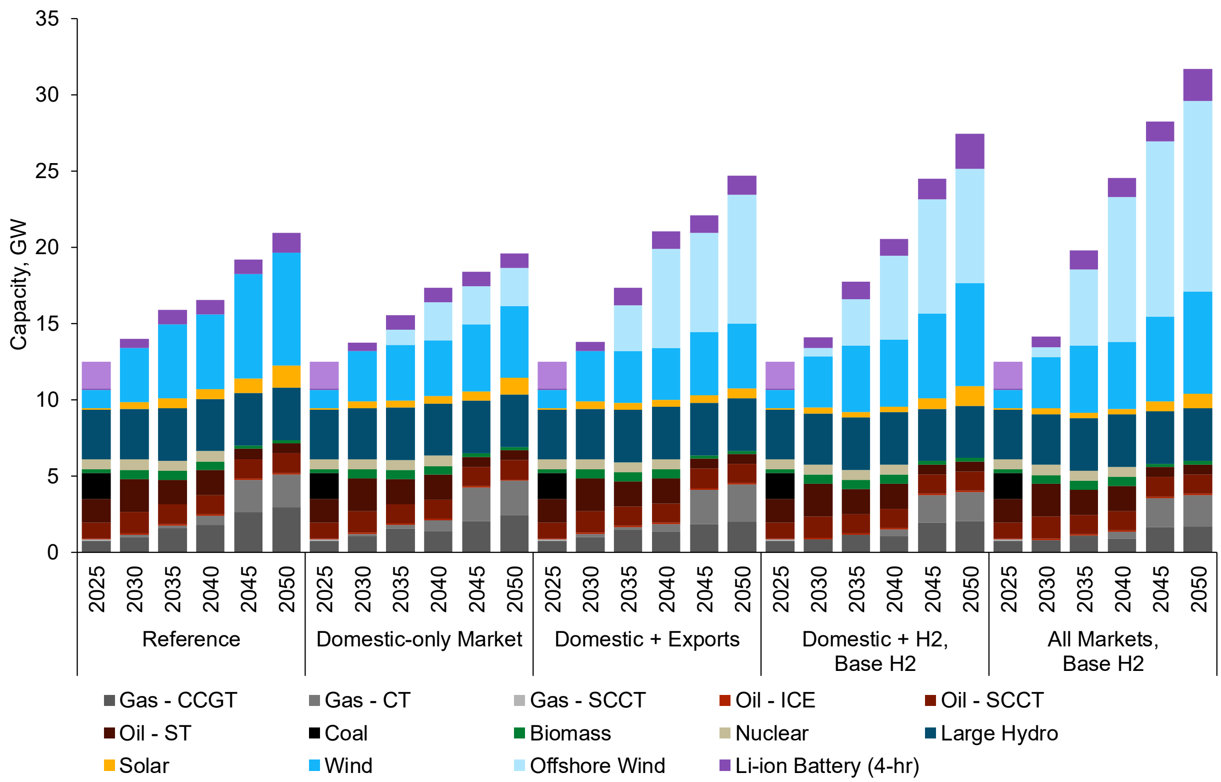
These results provide several key insights. First, absent specific policy to prioritize offshore wind, the model chooses to build primarily new incremental onshore wind to meet future energy needs across the region, driven by lower capital costs than offshore wind, particularly in the near term. Of the total installed capacity, economically-selected and grid-connected onshore wind builds represent almost 1 GW in 2030 and 5.4 GW in 2050 without offshore wind targets; this is on top of the 1.2 GW of planned builds by 2030 and 1.2 GW of existing capacity. In scenarios with planned offshore wind builds (e.g., representing a generic strategy or policy to build offshore wind), this alleviates the need for the region to build out significant new incremental onshore wind to meet demand. Given the higher capacity factors of offshore wind, new future incremental onshore wind buildouts are lower

[31] Appendix A reports additional results for key sensitivities on transmission and hydrogen.

than the Reference on a slightly higher than one-for-one basis with offshore wind, in the Domestic-only Market scenario (roughly 2.8 GW less onshore wind for 2.3 GW additional offshore wind in 2050). In cases where hydrogen demand is added to the system, new incremental onshore wind build outs grow alongside offshore wind, representing the need to have a somewhat more diverse resource mix, in which more than 15 GW of total wind generation capacity is utilized.

Despite significant offshore wind investment, the model selects natural gas (CT and CCGT) capacity to support resource adequacy and very limited generation needs. This is because modeling suggests the most critical conditions for regional resource adequacy occur in winter mornings. The modeling reflects the ability of dispatchable gas generation to support system reliability during the occasional periods of high load and low wind generation, despite offshore wind's high capacity factors which ensure that it can *usually* support winter needs.[32] Given fuel and operating costs, and the carbon tax, the gas units are generally expensive to run outside of these periods of critical need, and so operate at very low capacity factors, contributing very low generation or emissions to the region.

Figure 10. Total Atlantic Provinces Capacity (GW) Across Scenarios



[32] The ability of offshore wind to support regional resource adequacy needs will be further assessed in more detail after the completion of the technical potential and detailed output characterization developed in Phase 2.

Electricity Generation

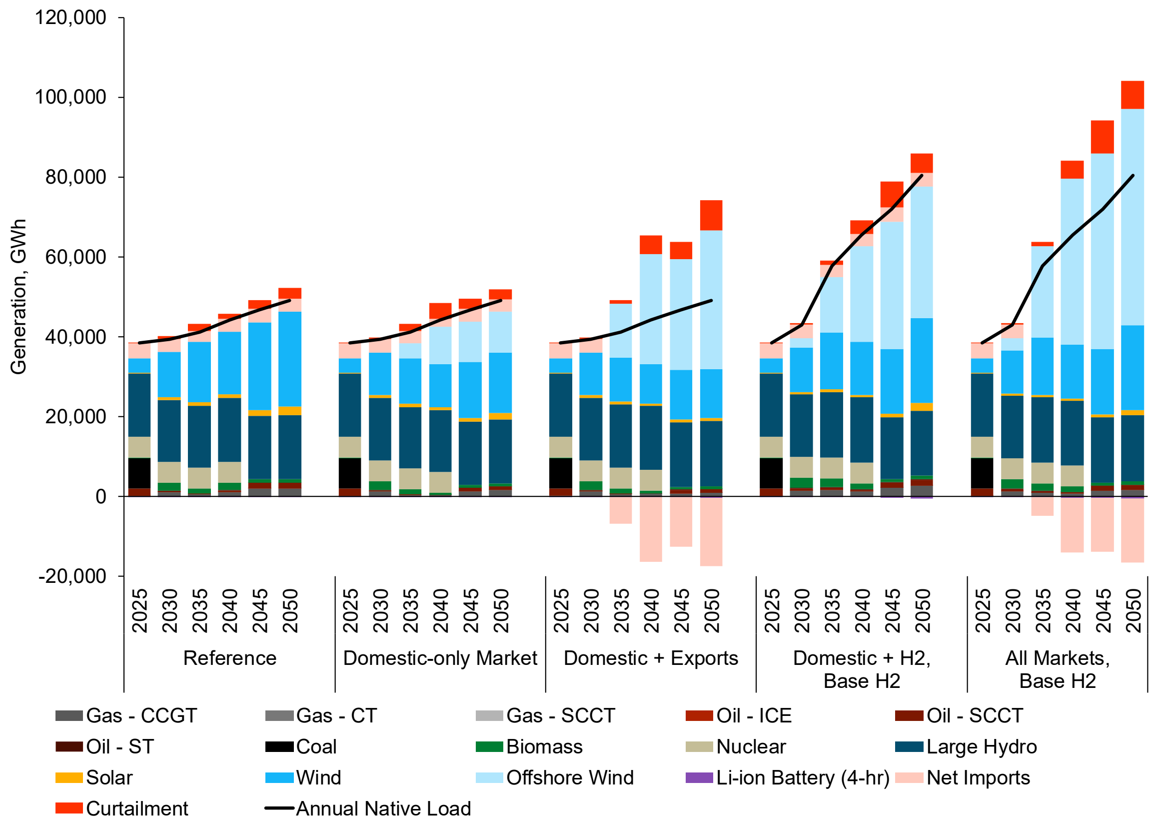
Given existing regional policy, most electricity demand is met with zero-carbon electricity across all scenarios by 2030, including the Reference scenario. When offshore wind is built as part of the scenario targets, it is able to provide a larger portion of overall clean energy end uses. As new load for hydrogen is introduced, or when new transmission/offtake opportunity via export markets is offered, this also drives greater demand, or offtake opportunity from the perspective of investors, and much higher levels of offshore wind generation.

With its higher capacity factor, offshore wind generation provides significant system-level support during both on-peak and off-peak hours. During winter months in the Domestic-only Market scenario, offshore wind provides an average of 10% of total generation in 2035 and 20.5% of total generation in 2050. However, this also leads to significant curtailment during off-peak conditions.

Notably, thermal generation remains largely unchanged across scenarios. Thermal generation provides dispatchable capacity during times of need, warranting continued operation in a select number of hours even with high offshore wind penetration. Largely, this need occurs during times when wind generation experiences prolonged lulls that cannot be covered by short-duration battery dispatch and when interprovincial transfer limits restrict resource sharing. Additionally, the quality and quantity of offshore wind generation within the Atlantic Provinces capitalizes on the export market opportunity to ISO-NE from Nova Scotia, as described below.

A deeper investigation of the role of offshore wind vis-à-vis thermal generation and export opportunities are explored in the Hourly Production Cost (Economic Dispatch) Analysis section. This section evaluates the portfolios using hourly production simulation modeling, generating more precise estimates of hourly dispatch under a range of system conditions, refining the characterization of offshore wind's interaction with other resources.

Figure 11. Total Atlantic Provinces Generation (GWh) Across Scenarios



Electricity Interprovincial Flows and Exports

A key enabler of offshore wind offtake is the ability to move it across provinces. The Phase 1 assessment modeling focused on the existing interprovincial transmission links and corresponding flows, with limited representation of additional new transmission largely focused on the ability to move clean energy to external markets. In the Interprovincial Transmission Expansion Assessment, the study more deeply explores interprovincial and external linkages, expansion potential, and interactions between interprovincial transmission and economically selected offshore wind resources.

Regardless, the existing transmission links between provinces are already critical for serving load and economically dispatching new resources. The Nova Scotia to New Brunswick tie is particularly important across scenarios, given the wind potential in Nova Scotia and the load growth projected in New Brunswick. This can be observed even in the Reference scenario, where line utilization increases from Nova Scotia to New Brunswick between 2030 and 2050, as shown in Figure 13.

Cases with high levels of offshore wind builds drive even higher levels of line utilization between Nova Scotia and New Brunswick, as seen in Figure 23 in the "Market Opportunity to Support Exports" section. In many hours that intertie is at max capacity in these cases, leading to some offshore wind curtailment when there is excess generation feeding into Nova Scotia but no additional ability to export it. Even in scenarios with expanded transmission capacity to ISO-New England, energy exports are not always financially viable and the line limits between Nova Scotia and New Brunswick (300 MW in the New Brunswick direction) inhibit excess Nova Scotia offshore wind from being exported to New Brunswick. This excess is then curtailed as shown in Figure 12. In the Production Cost Analysis, more detailed hourly modeling and a broader range of strategies for reducing curtailment is explored.

Figure 12. Annual Generation (GWh), All Scenarios, by Province

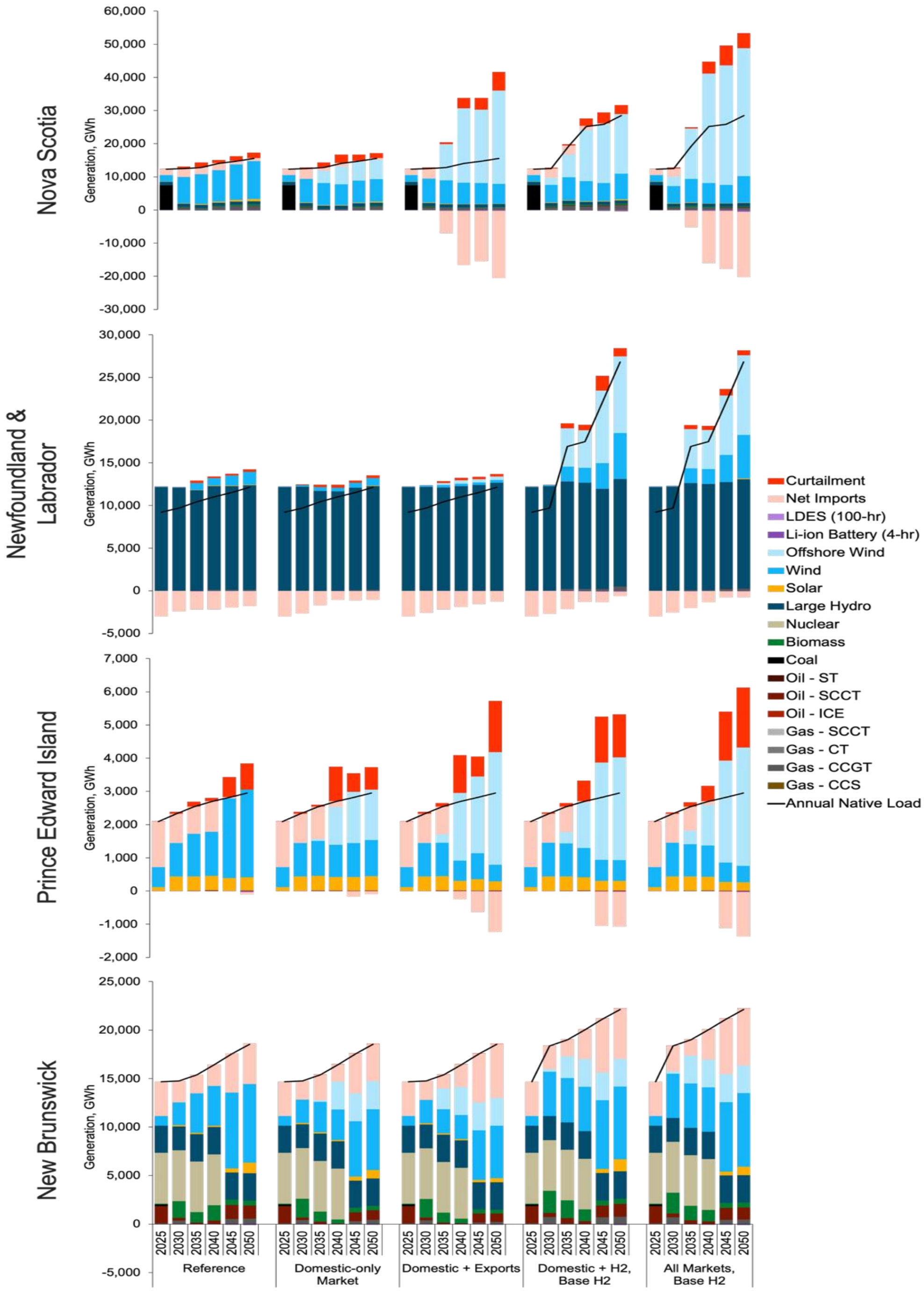
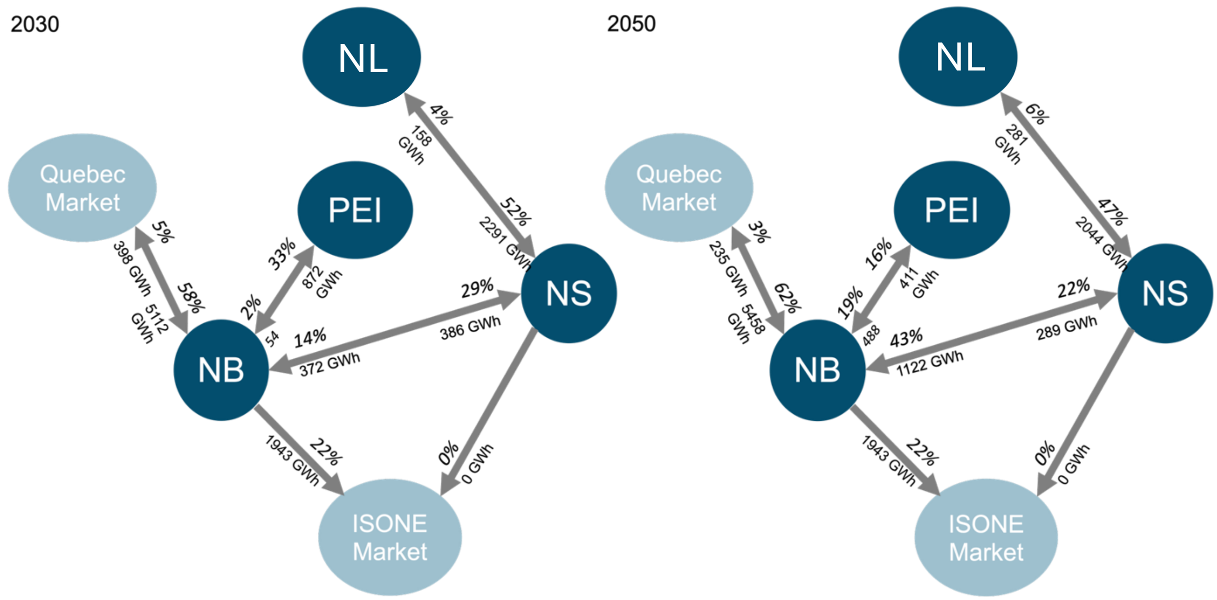


Figure 13. Reference, Line Utilization (%) and Flows (GWh) for 2030 and 2050



Note: This is the Reference case, in which no additional transmission is built to New England or across provinces. Figure 23 below illustrates scenario flows when additional transmission to New England is built. This study does not directly model transmission linkages between Labrador and Hydro Quebec due to lack of publicly available data on Labrador loads and import/export flows between Labrador and Quebec. Instead, flows south across the Labrador Island Link are captured, as is full load/resource representation for the Newfoundland Island System and the links to Nova Scotia. Together, these capture the interactive effects of Labrador-based generation on resource portfolios and dispatch elsewhere in the region. For additional detail on model set-up see the "Modeling Framework" section above.

Scenario Cost Comparison

The study models the cost of the electric grid as investments are added to meet increasing load and system needs.[33] PLEXOS minimizes the sum of generation-related new fixed costs and system operating costs, discounted to the present year. Fixed costs include investment in new generating resources and any associated interconnection and transmission required to deliver clean energy to loads, as well as fixed O&M and any associated variable O&M costs. Fixed costs are reduced when existing resources are retired. Variable costs include fuel and variable O&M, which are reduced as incremental clean energy resources are added and utilization of fuel-based resources declines. The cost of imports reflects the total energy costs associated with these imports, and the revenue associated with exports reflects the energy revenues earned.

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[33] Note that this does not include the fixed costs associated with the existing system and utility planned/under construction resources through 2030 and therefore is not itself a full representation of system costs or revenue requirements. However, it does reflect key elements of costs that might ***vary or differ*** across scenarios and pathways.

Consistent with decarbonization planning expectations in most jurisdictions, total power sector costs in the Atlantic Provinces are projected to increase in all scenarios. This is driven by a range of factors, including load growth, the need for new local transmission, and the development of a new, non-emitting generation fleet. Offshore wind development specifically plays a role in that, and the model shows higher costs in scenarios with greater planned offshore wind deployment. This is expected since offshore wind has higher cost expectations relative to onshore alternatives, though it is partially mitigated in scenarios with greater export market access, as sales to neighboring regions improve the economic viability of offshore wind projects.

Figure 14 below helps illustrate these dynamics across cases. This chart shows the modeled annual cost of energy across scenarios, expressed in nominal cents per kWh. The annual cost of energy rises in all cases relative to the reference case, with the domestic market only case showing only a modest increase (2.92 cents per kWh nominal in 2050 above reference), and the other scenarios that model larger offshore wind builds (and in the case of the hydrogen scenarios, higher loads as well) showing more meaningful increases (about 6.25-12.50 cents per kWh in 2050 above reference, after accounting for export revenues).

Figure 14. Modeled (Partial) Cost Comparison, Difference in Annual Cost of Energy (nominal ¢/kWh) Relative to Reference Across Scenarios

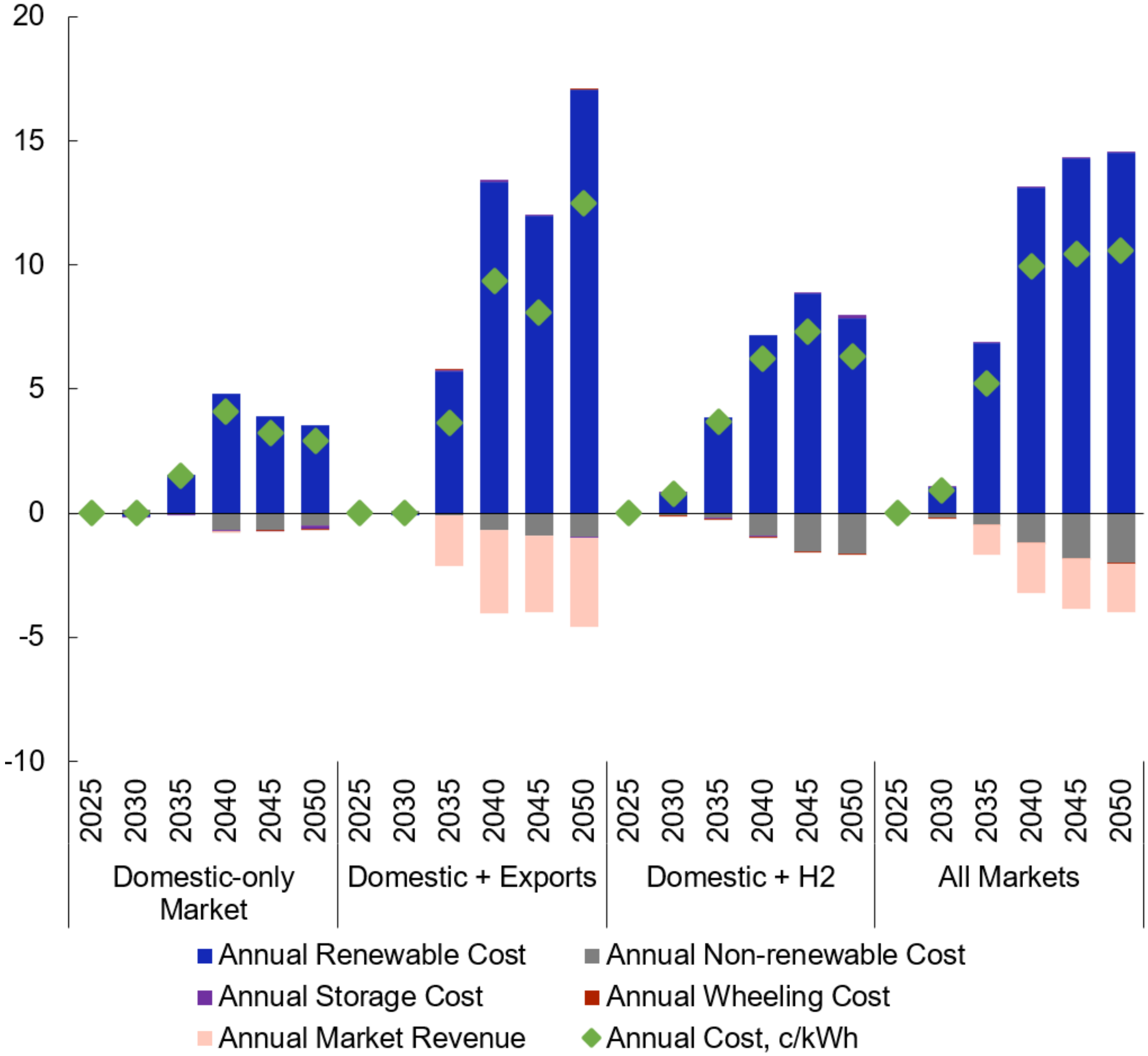
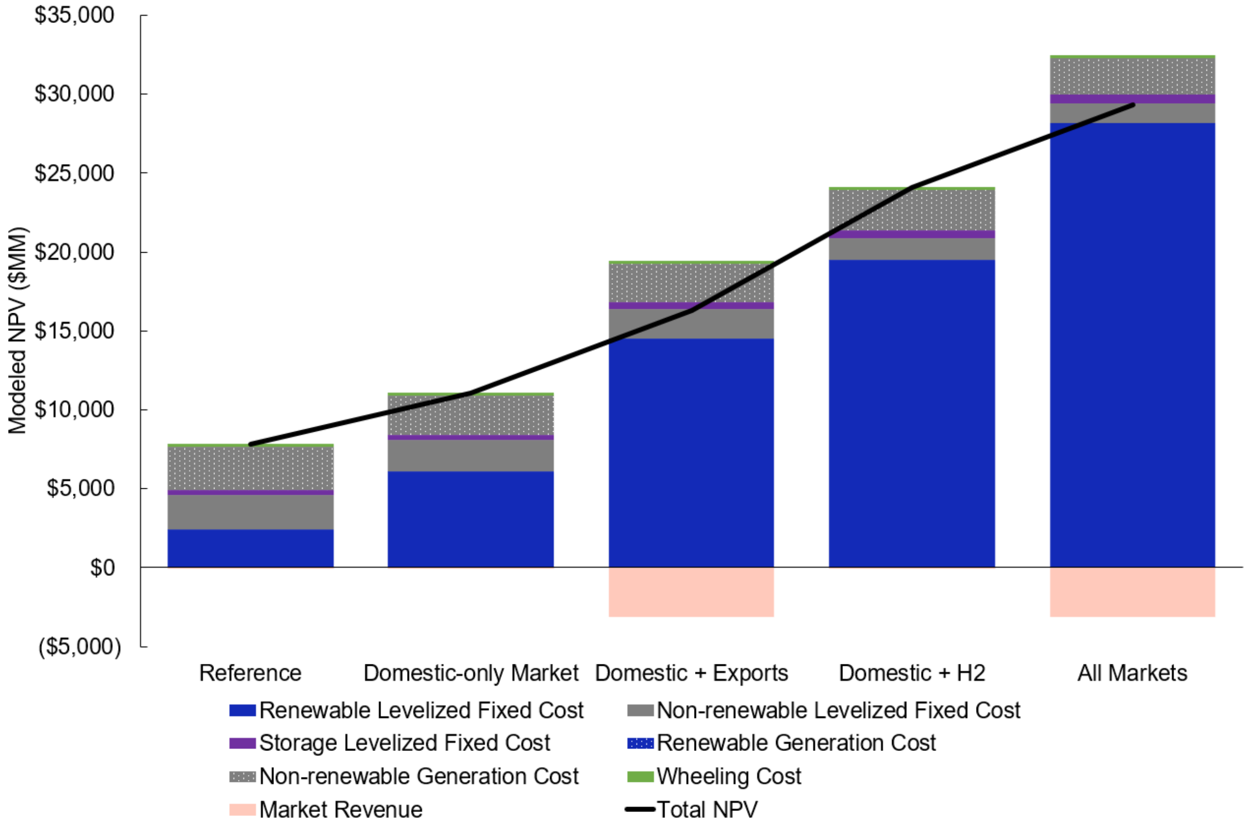


Figure 15 shows the modeled net present value (NPV) across scenarios. The NPV of total costs similarly increases across scenarios, reflecting the cumulative impact of offshore wind investments and, for the hydrogen cases, increased loads. The NPV of renewable fixed costs in the All Markets scenario rises from $702 million in 2030 to almost $13.7 billion by 2050. Both renewable and non-renewable generation costs show gradual increases, though fossil generation costs decrease in scenarios prioritizing offshore wind. Wheeling costs increase with higher offshore wind penetration as interprovincial energy flows grow to balance supply and demand. These costs become relevant in scenarios with significant export market integration, such as the Domestic + Exports and All Markets scenarios. In the Domestic + Exports and All Markets scenarios, market revenues from ISO-NE and other external markets provide significant offsets, lowering the overall NPV.

Figure 15. Modeled Cost Comparison, Total Net Present Value (NPV) Across Scenarios



In Table 11, E3 compares the modeled annual cost of energy and NPV in 2050 of all scenarios compared to that of the Reference scenario. This table summarizes the key cost trends, highlighting cost increases as offshore wind penetration and market complexity (hydrogen and exports) increase across scenarios.

Table 11. Modeled Cost Comparison, Annual Cost of Energy and Net Present Value Compared to Reference Scenario

Scenario	Annual Modeled/Partial Cost of Energy, 2050 (¢/kWh)	Percent Increase vs. Reference	NPV as of 1/1/2024, 2025-2050 ($billion)	Percent Increase vs. Reference
Reference	6.49	-	$7.83	-
C1, Domestic-only	9.41	45.0%	$11.07	41.4%
C2, Domestic + Exports	18.99	192.4%	$16.27	107.7%
C3, Domestic + H2	12.83	97.5%	$24.11	207.8%
C4, All Markets	17.08	163.1%	$29.35	274.7%

Note: This has not been benchmarked to retail rates. Annual Modeled/Partial Cost of Energy reflects new investment and operational costs in 2050. Note that the cost of new transmission to New England are not factored into the above costs.

While offshore wind integration is costly, its potential strategic value lies in its ability to help meet decarbonization targets, earn revenue from export markets if conditions are favorable, spur job growth and industrial development in the region, and potentially provide other benefits. Revenue from exports to New England could improve the economic case for offshore wind but overall impacts on system costs from the associated incremental offshore wind builds become dependent on energy prices in those markets, as well as the costs of transmission to those markets. The New England price strip analysis includes substantial offshore wind development in the New England market as well, which depresses prices during many of the hours that offshore wind from Atlantic Canada is available; substantial delays or reductions to this resource buildout in New England could have material impacts on the revenue generated from offshore wind exports in Atlantic Canada. These markets align with Canada's decarbonization goals and provide a critical value stream. The extension of tax incentives beyond 2034 could significantly reduce upfront capital costs and enhance overall cost-effectiveness. This would reduce the cost of offshore wind deployment in the Atlantic Provinces. The study also does not model the costs of new transmission to New England; this cost and its allocation across parties will influence the viability of export markets.

Market Opportunity to Support Domestic Consumption

Domestic loads in the Atlantic Provinces absorb about 1 GW of offshore wind development by 2035, increasing to 2.5 GW by 2040, with that level maintained through 2050. At these build levels, the system can relatively easily integrate and utilize the offshore wind, particularly during times of need in the winter, and little offshore wind curtailment is observed. As the Atlantic Provinces decarbonize their electric grid, electrification of vehicles and buildings increases loads annually, as well as coincidentally with higher winter offshore wind generation patterns. Select dispatch charts across provinces, shown in Figure 16 and Figure 17, help illustrate these dynamics. The phase-out of coal and other fossil fuel-based generation adds to the system need for new generation to serve growing loads. Given these dynamics, offshore wind has the potential to support the Atlantic Provinces achieving their decarbonization goals.

In addition to diversifying and expanding the region's clean energy supply, early investments in offshore wind could create a range of additional benefits. These include economic development and job creation through the growth of an offshore wind industry, leveraging the region's strong marine-oriented workforce and research expertise. Such investments can help position the Atlantic Provinces as leaders in offshore wind technology, building on existing strengths in marine innovation. Regional offshore wind development also supports reduced reliance on imported energy and fuels, enhancing energy security and resilience to global market disruptions.

Despite its potential, this remains a higher-cost pathway under current cost projections compared to scenarios that rely more heavily on onshore wind to meet domestic needs. A limited amount of offshore wind becomes cost-effective over time, and anticipated cost declines in the medium to long term could improve its competitiveness. Moreover, constraints on land availability for onshore wind development may further enhance the relative attractiveness of offshore wind.

While many enablers are needed for offshore wind development to support domestic markets, key focus areas identified through the regional assessment included:

+ **Lowering costs:** As noted throughout the report, offshore wind remains significantly more expensive than onshore wind today. However, as land becomes increasingly constrained, particularly in provinces like Nova Scotia, offshore wind may offer a valuable alternative. To reduce costs, it is important to identify offshore sites with high quality offshore wind resources and the least transmission need, and to identify transmission configurations that maximize infrastructure utilization, thus making per-unit output more cost effective. At the same time, the region should leverage its maritime expertise to drive down development costs—through greater coordination across marine industries and by applying shared knowledge in building, operating, and maintaining infrastructure in coastal environments.
+ **Ensuring regional coordination**: Modeling results show relatively low curtailment in the Reference and domestic consumption-focused scenarios, indicating sufficient transmission capacity to move wind power to areas of demand. However, in scenarios exploring broader offtake opportunities, curtailment increases, particularly where offshore wind buildout is higher. Enhancing transmission into New Brunswick, for example, would support greater utilization of offshore wind and help reduce curtailment. More broadly, strengthened regional coordination will allow electricity to flow more efficiently across provinces, reducing congestion and improving overall system reliability.

Figure 16. Domestic-only Market Dispatch (MWh), 2035 Winter Week

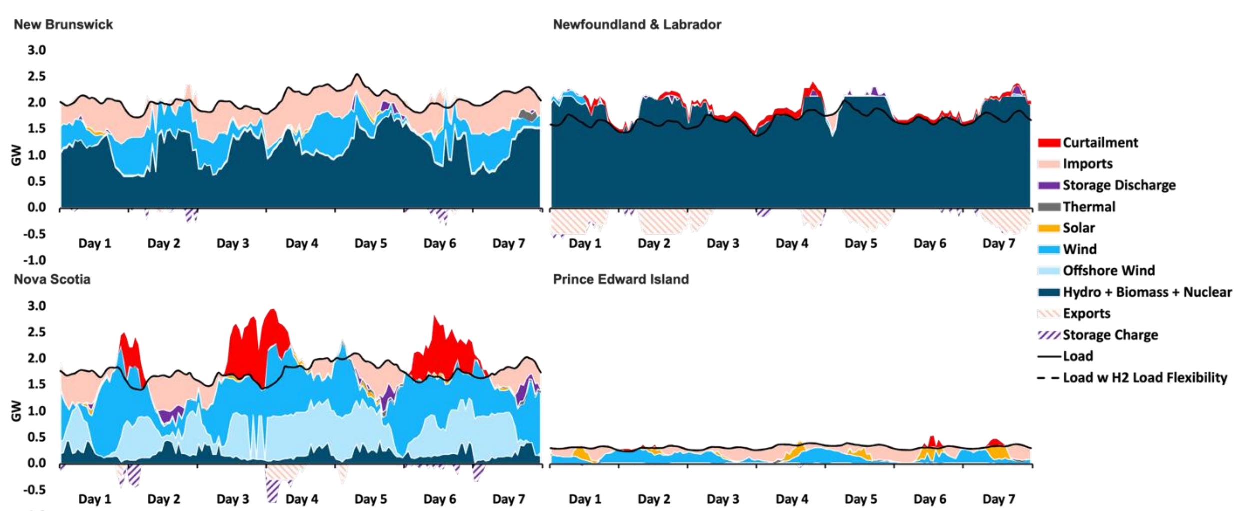
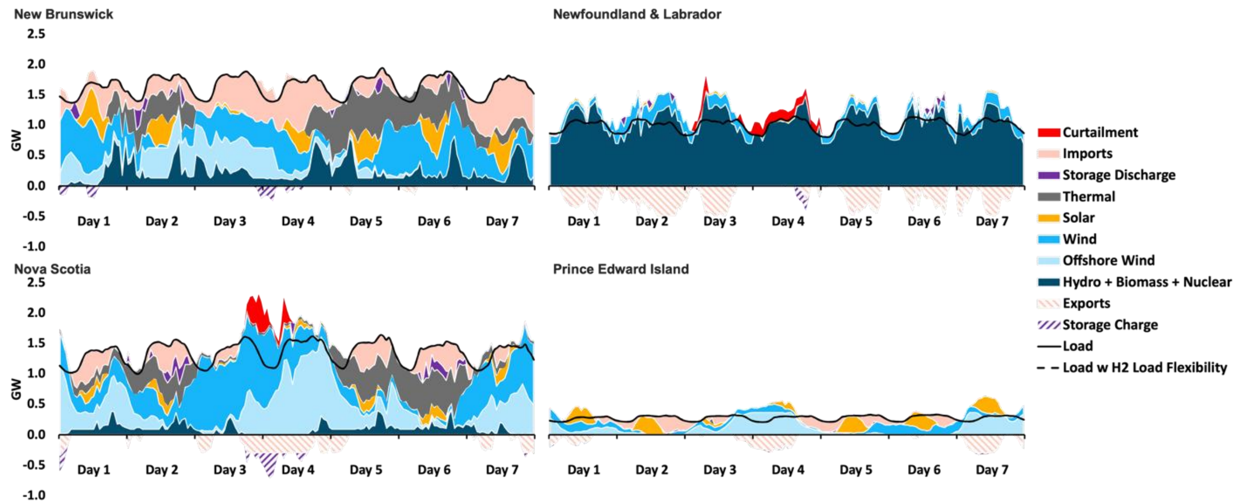


Figure 17. Domestic-only Market Dispatch (MWh), 2050 Fall Week



Market Opportunity to Support Exports

Export markets provide a key additional opportunity for offshore wind in Atlantic Canada. While meeting growing domestic demand can support a more limited industry, access to external markets would enable the region to significantly scale the offshore wind industry, driving greater economies of scale and bringing revenue into the region. Growing regional ties would also facilitate more efficient supply/demand balancing, reduce curtailment, and increase offshore wind utilization.

To explore the role of exports in enabling larger offshore wind buildouts, the study included market transaction opportunities with two neighboring regions: ISO New England (ISO-NE) and Hydro-Québec (HQ). Of the two, ISO-NE represented the larger *modeled* opportunity, with offshore wind capacity matched by expanding transmission between Nova Scotia and ISO-NE—up to 2,000 MW by 2035, 4,000 MW by 2040, and 6,000 MW by 2050. ISO-NE was modeled using a fixed market price curve based on the Boston zone, selected given it represents a large load center and would be most able to absorb high volumes of offshore wind. This structure allowed the model to simulate economically viable export-driven offshore wind development, reflecting realistic price signals from a major U.S. market. Hydro-Québec was also included in the export analysis, though it represented a smaller *modeled* opportunity with its 1 GW transmission limit. In reality, HQ's overall system size and electricity demand are larger than ISO-NE's; however, due to limited data availability and price transparency in the HQ market, it was modeled conservatively.

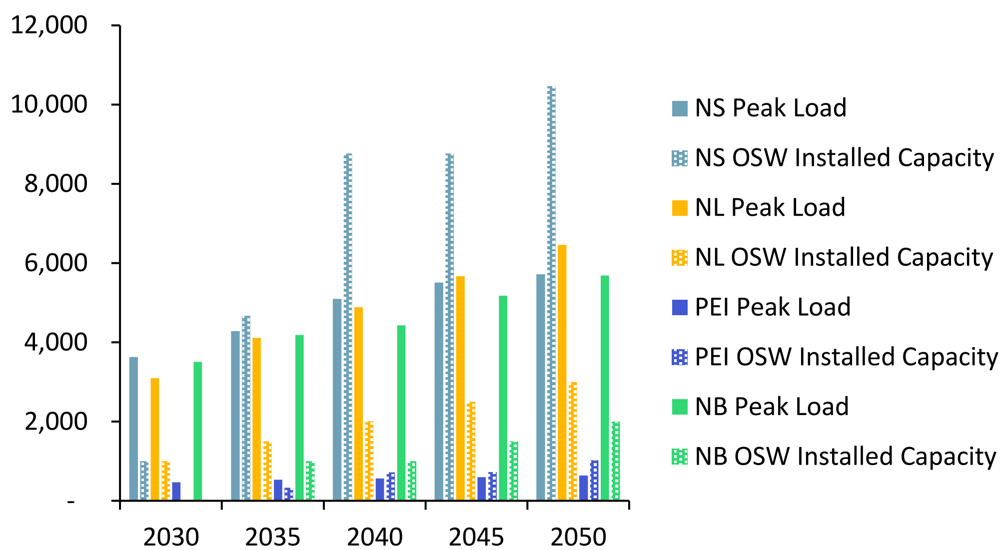
Market exports occur if the following conditions are met:

1. There is an excess of offshore wind generation that cannot be used to meet local loads.
2. Prices in the external market are high enough for offshore wind exports from Atlantic Canada to be financially viable (e.g. external price exceeds relevant hurdle rates, as discussed below)

The first condition, indicating an opportunity for exports of excess offshore wind generation, can be met for two main reasons. The first is that in some provinces, offshore wind generation exceeds loads. Figure 18 depicts peak loads and installed offshore wind capacity across Atlantic Provinces and indicates an excess of offshore wind relative to loads in Nova Scotia and Prince Edward Island. New Brunswick, which has more limited access to offshore wind resources, has sufficient load to self-consume most local offshore wind generation.

The second reason for excess offshore wind generation is inter-provincial transfer limits acting as a barrier to moving excess offshore wind between Atlantic Provinces. This transmission constraint was most apparent between Nova Scotia and New Brunswick, the largest load center.

Figure 18. Provincial Peak Loads and Offshore Wind Installed Capacity in Export Scenarios



When there is excess offshore wind within a province that either cannot reach loads in other Atlantic Provinces *or* there is no need in other provinces, it becomes available for export. Hydro-Québec exports are limited by the transmission capacity between Nova Scotia and New Brunswick; in order to reach Quebec, excess offshore wind in Nova Scotia must first flow into New Brunswick. As a result, the modeling results show very few exports to Hydro-Québec, as illustrated in Figure 23 where annual transmission utilization in the direction of the Hydro-Québec market does not exceed 4% in export cases.

To consider exports into ISO-NE, the model considers periods in which there is excess offshore wind in the Atlantic Provinces and evaluates whether hourly market prices create attractive export opportunities. When prices are high, excess offshore wind may be exported. When prices are too low, that excess generation is curtailed. This curtailment due to uneconomic export conditions can be seen in Figure 12. ISO-NE prices in a given hour[34] must exceed the $5.31 marginal cost of offshore wind exports from the Atlantic Provinces to warrant exporting over curtailing excess generation. The marginal cost of offshore wind exports is comprised of two main parts. The first is a $2/MWh integration charge placed on all renewables in the model, representing the cost to stabilize the grid under deep decarbonization scenarios. The second is a $3.31/MWh wheeling charge placed on all exports meant to encourage local consumption over exports.[35]

Figure 19 through Figure 22 depict how the conditions that enable economic exports to external markets contribute to either economic exports or curtailment. The charts depict month-hour average conditions in a 2040 sample year, for scenarios with exports and hydrogen loads. Figure 19 shows that curtailment of offshore wind occurs during spring and summer midday hours, which coincides with times when ISO-NE market prices are lowest, as illustrated in Figure 20. Similarly, when prices are low and offshore wind generation is being curtailed, Figure 21 shows low utilization of the transmission tie from Nova Scotia to ISO-NE. But when ISO-NE prices are high, curtailment is low, and line utilization is near its max. We also see in Figure 22, that in spring and summer midday periods when exports to ISO-NE are not economic, utilization of the Nova Scotia-New Brunswick tie is maxed out. This indicates that the line's maximum transfer capability is limiting excess generation from reaching New Brunswick loads and the Hydro-Québec market.

Based on these results and the underlying dynamics, the regional assessment identified several key enablers for offshore wind deployment to support export markets, including but not limited to:

- **Lowering costs of offshore wind**: As described above, the cost of offshore wind from the Atlantic Provinces must continue to decrease to compete in U.S. markets. New England states, such as Massachusetts, are actively procuring offshore wind projects to meet their growing energy demands, though this has been largely paused given the Trump administration's executive order to halt new offshore leasing and permitting. To effectively compete with these local resources and generate buy-in from New England ratepayers, the Atlantic Provinces must demonstrate that their higher energy output can offset the additional transmission costs, resulting in a competitive all-in levelized cost of energy or power purchase agreement price. While this presents a significant challenge, many New England planning studies indicate a need for over 30 GW of offshore wind capacity. This suggests that Atlantic Provinces' offshore wind could secure a place on the supply curve by offering competitive pricing or by demonstrating greater feasibility compared to certain New England-based projects.
- **Ability to permit and cost effectively build GW-scale new transmission:** Offshore wind will only be valuable if it can be transported to demand sources to the south (e.g. New England or New York) or west (e.g. Quebec or Ontario) at low enough costs to be

[34] ISO-NE prices fluctuate hourly, set by the marginal energy resource needed to serve load in a given hour in the New England market. Dispatch and import/export decisions within the model respond to these price signals, optimizing around the least cost fixed and operational portfolio – subject to constraints – in Atlantic Canada.
[35] Note that the cost to develop incremental export capacity between Atlantic Canada and New England has not yet been included in this modeling. If expanded interregional transmission is developed, and if the provinces take on a meaningful portion of that investment and development, then that would impact optimal portfolio findings.

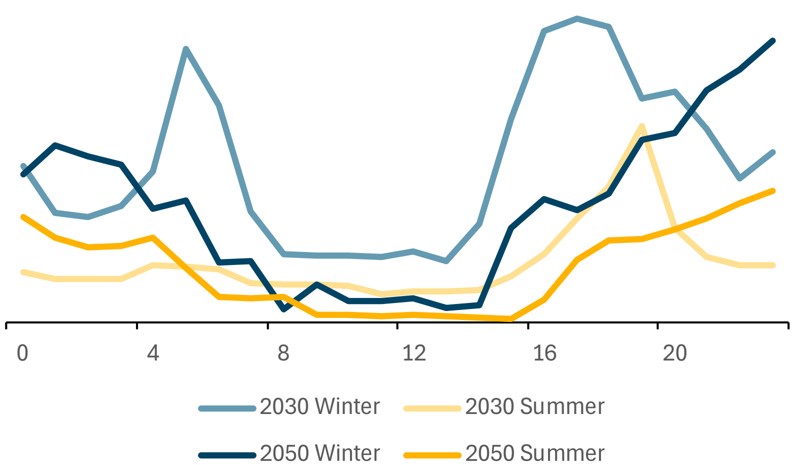
competitive with clean energy alternatives within those regions. Large amounts of transmission are required (GW-scale) to ensure enough offshore wind can be effectively used, and this requires the ability to build transmission. To access New England, this could take the form of subsea HVDC lines, which can be more cost effective over long distances, and may avoid permitting or environmental challenges on land, enable delivery of large quantities of energy, reduce the distance of cable needed, and facilitate lower energy line losses. Offshore wind projects could also demonstrate that they are environmentally preferable, or a better option for New Englanders from a siting perspective. The range of options for transmission connection into New England or other neighboring regions can be further explored in a follow-up study.

+ **International alignment and coordination on key aspects of projects:** Developing a cross-border energy project requires collaboration across multiple dimensions, including regulatory alignment, infrastructure development, and market integration. This involves ensuring compliance with diverse energy, environmental, and permitting laws and policies in both countries. Offshore wind projects must also meet the market rules and requirements of ISO-NE to ensure successful participation. Additionally, substantial technical coordination and contingency planning are essential to address risks related to supply obligations, system integration, and potential outages. Commitment to cost-effective pathways to net-zero in both regions may be a valuable springboard to this, but significant coordination will be critical to large-scale international clean energy markets.
+ **Load materializing at scale in other markets:** Offshore wind will only be valuable to New England if load growth materializes in-line with net-zero targets. Today, New England is summer peaking; however, a transition to winter peaking is expected by the early 2030s. This change is driven by the electrification of heating to achieve decarbonization targets, which could more than double the region's winter peak demand. Such a shift would contribute to periods of greatest resource insufficiency in the winter and make offshore wind significantly more valuable to the region. However, realizing this transition is essential for offshore wind to deliver its full potential value to the region.

Figure 19. All Markets, Season-Hour Average Offshore Wind Curtailment in 2040 (MWh)

Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Winter	110	139	198	130	106	143	360	491	698	771	703	516	577	540	203	19	-	13	6	13	27	8	24	12
Spring	1,193	1,014	998	1,293	1,321	1,202	824	1,845	1,689	1,774	2,319	1,634	1,490	1,694	1,447	1,301	511	373	72	180	84	168	112	308
Summer	6	29	32	60	63	47	8	20	-	9	-	151	38	24	24	24	-	14	10	86	50	6	84	195
Fall	48	89	84	107	68	28	115	43	49	34	267	288	62	168	278	-	-	1	2	22	35	10	46	42

*Figure 20. Season-Hour Average Price Shape**



* Note: Y-axis not included given confidential information.

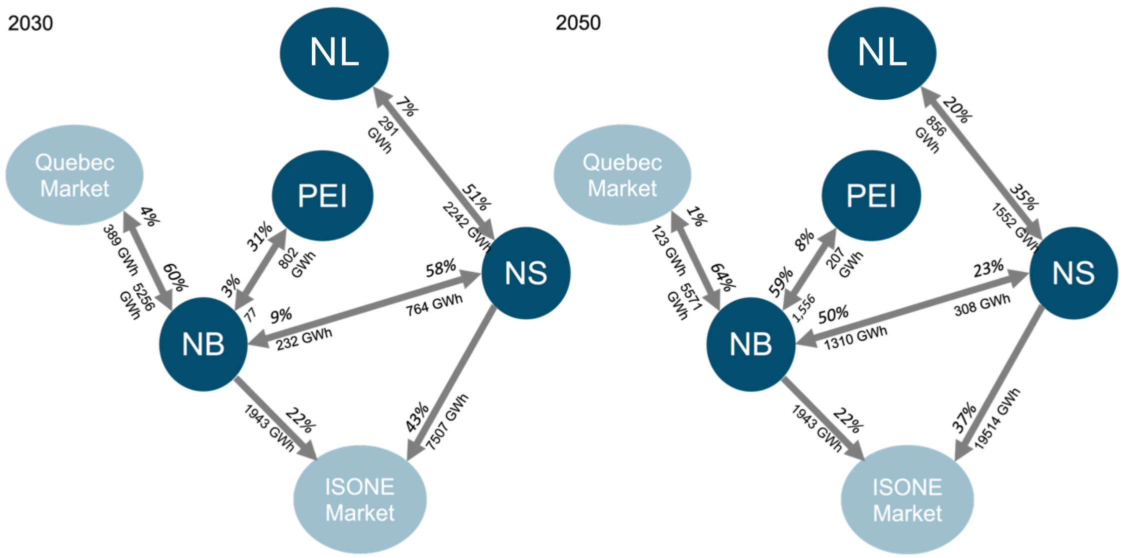
Figure 21. All Markets, Season-Hour Line Utilization from Nova Scotia to ISO-NE in 2040 (%)

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Winter	92%	92%	89%	90%	93%	87%	75%	76%	67%	67%	65%	58%	55%	41%	51%	76%	58%	35%	16%	14%	24%	45%	65%	71%
Spring	71%	75%	67%	69%	68%	61%	52%	2%	2%	2%	0%	0%	2%	7%	18%	18%	38%	65%	61%	68%	53%	50%	59%	58%
Summer	62%	55%	50%	41%	38%	12%	11%	11%	8%	13%	11%	10%	18%	16%	17%	32%	31%	48%	67%	70%	73%	67%	71%	77%
Fall	54%	64%	63%	68%	63%	84%	68%	59%	73%	70%	39%	44%	59%	47%	46%	54%	42%	43%	58%	59%	62%	46%	58%	52%

Figure 22. All Markets, Season-Hour Average Line Utilization from Nova Scotia to New Brunswick in 2040 (%)

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Winter	26%	28%	42%	49%	46%	35%	36%	47%	56%	60%	54%	59%	65%	62%	56%	35%	16%	10%	0%	6%	22%	23%	19%	17%
Spring	21%	33%	8%	12%	10%	2%	22%	41%	26%	34%	34%	12%	8%	25%	8%	12%	15%	21%	10%	0%	2%	24%	11%	25%
Summer	44%	45%	38%	30%	17%	17%	33%	35%	41%	39%	42%	36%	59%	59%	58%	41%	58%	38%	46%	53%	58%	57%	45%	19%
Fall	64%	51%	63%	63%	54%	54%	62%	47%	51%	49%	44%	35%	35%	44%	31%	31%	38%	42%	26%	27%	27%	27%	34%	34%

Figure 23. All Markets Scenario, Line Utilization (%) and Flows (GWh), All Provinces for 2035 and 2050



Note: All Markets scenario includes offshore wind serving domestic loads, exports to New England, and base levels of hydrogen demand.

Market Opportunity to Support Green Hydrogen

The future of Canada's hydrogen industry remains uncertain, as it is still in its early stages and depends on the evolution of both domestic and global demand, as well as the region's ability to produce cost-competitive hydrogen. As noted above, hydrogen is a well-established energy source, and when produced from offshore wind or other renewable resources, it can serve as a zero-carbon fuel in hard-to-decarbonize sectors, including high-temperature industrial applications, heavy duty transportation, maritime industrial uses, and peaking power generation.

Today, enthusiasm is rapidly growing for hydrogen production facilities in the Atlantic Provinces, with new projects announced each year on the order of gigawatts. Hydrogen developers cite the potential for the Atlantic Provinces to become a major hydrogen exporter, particularly to Europe, a region with ambitious decarbonization targets and convenient maritime access. In March 2024, Germany and Canada entered a $600 million dollar agreement to invest in building the infrastructure in Canada required to export hydrogen to Germany.

Offshore wind's potential to scale contributes to its potential to support green hydrogen. With high build potential for onshore and offshore wind resources, along with very high offshore wind capacity factors, the Atlantic Provinces' hydrogen economy could be powered by its valuable clean energy. On the other hand, comprehensive analysis that calculates the cost of hydrogen production in the Atlantic Provinces finds that the cost of production, particularly from offshore resources, will need to decrease meaningfully to become competitive on a global scale.

To help inform its assessment of hydrogen's potential, E3 conducted a production cost analysis focused on the Atlantic Provinces using its REMATCH tool, which uses hourly market price and grid emission forecasts to calculate the economic sizing of clean energy resources to electrolyzer capacity, the associated optimal operational strategy, and the subsequent levelized cost of producing hydrogen. These cost results are reported in Appendix B.5 and illustrate that lowering the costs of hydrogen production will be a key challenge in scaling hydrogen in the Atlantic Provinces.

While today, hydrogen loads remain uncertain, the modeling also demonstrated that hydrogen loads have the potential to be very large, if they can both serve domestic end uses and compete globally. While serving potential domestic hydrogen demands with wind resources might require on the order of 2 GW offshore wind in 2035 to 4 GW offshore wind in 2050, serving much larger export markets with hydrogen could make the development of hydrogen not limited as much by the amount of offtake, but simply by how much land, storage, and other infrastructure can be built out in the region.

Broadly, select key enablers to build out a robust hydrogen industry in the Atlantic Provinces include:

+ **Policy and government support to drive domestic utilization of hydrogen**. As described in the modeling assumptions, the Atlantic Provinces could use hydrogen to decarbonize hard-to-abate emitting industries like higher-temperature industrial processes, natural gas replacement in peaking power plants, heavy duty trucking, aviation, and other end uses like oil and gas refining. However, regulatory and financial support will be critical to creating market and regulatory frameworks, reducing costs, and ensuring safety if and as the industry scales. Credible government policy signals can also help attract private capital for investment in production of hydrogen.
+ **Reduction in costs across all aspects of hydrogen production from offshore wind.** Lowering the costs along the entire hydrogen and offshore wind supply chain is critical to help this nascent industry scale. While global electrolyzer deployment will help reduce capital costs, strategic siting of hydrogen projects near the clean energy resource, in this case offshore wind, is also very important. The study modeling showed significant curtailment in hydrogen scenarios in which even a small portion of the hydrogen was produced in a different province than its renewable source, given the thin transmission connections across provinces. This underscores the importance of co-locating demand and production to minimize curtailment and maximize wind utilization.[36] Siting close to offshore wind also reduces overall transmission needs and costs. Siting at or near underground storage, typically the cheapest storage option, enables higher seasonal hydrogen production and delivery to demand centers.
+ **Building out the hydrogen supply chain**. A robust supply chain (e.g., production, transportation, storage) will be needed to support both domestic and international markets, with a particular focus on safe and cost-effective transportation methods.

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[36] In Phase 2, E3 adjusted the locations of hydrogen loads (i.e., assumed production locations) to match where the best wind is built. In Phase 1, hydrogen production and therefore demand was spread somewhat more evenly across provinces.

Innovations in hydrogen shipping, including advancements in compression and liquefaction technologies, will be critical for serving international export markets. However, evaluating the costs and logistics of transporting hydrogen over long distances, whether as liquefied hydrogen or ammonia, introduces significant additional uncertainty and new complexity to serving export markets that have yet to be fully developed at scale.

+ **Durable international policy and secure offtake contracts to reduce production risks.** While the Atlantic Provinces have abundant renewable resources, securing offtake for hydrogen is critical to lowering the risk of hydrogen production and getting early projects built. One prerequisite is for international countries to have long-term, enforceable policies that require or incentivize hydrogen, which will drive investor confidence and enable investment. International buyers also need to ensure steady revenues to projects, to mitigate risk and exposure to uncertain and not-yet-existing global markets. Given the highly capital-intensive nature of hydrogen projects and the evolving global hydrogen economy, policy and/or market stability and a secure offtake agreement are needed to drive investments.
+ **Demonstrated successful and operational commercial projects.** Hydrogen projects will remain uncertain in terms of safety, feasibility, and cost until commercial-scale projects are successfully developed and operationalized, with supporting infrastructure. These factors make it difficult to predict with certainty the long-term viability of this industry. This uncertainty is not unique to the Atlantic Provinces and is evolving quickly as an increasing number of projects reach the late stages of development. These early commercial projects, particularly those in North America, will be critical to demonstrate feasibility, reduce risks, and drive down costs through learning-by-doing.

Given the current limited number of commercial operational hydrogen projects, the offtake potential for hydrogen produced in the Atlantic Provinces is still developing. Regional demand for hydrogen has not yet materialized, and global demand for clean hydrogen remains in its early stages, with supply chains, regulatory frameworks, and market signals still emerging. Additionally, competition from other regions with lower labor and material costs and closer access to major European markets may influence the competitiveness of Atlantic Canada's hydrogen exports.

Interprovincial Transmission Expansion Assessment

In the core scenarios with high levels of offshore wind adoption, existing transmission transfer capacities emerged as a limiting factor for efficient sharing of generation capacity, particularly during high wind output periods. Two scenarios were developed to explore the economic potential for additional interprovincial transmission capacity. These scenarios enable the model to co-optimize new investments in interprovincial transmission alongside generation resources and batteries.

The transmission expansion cases utilized the Domestic Market Only case and the All Markets with High Hydrogen case. These cases represent the low and high ranges of offshore wind deployment levels studied in our core scenarios, allowing the analysis to assess how the value of new interprovincial transmission varies with the scale of offshore wind adoption. In both cases, candidate lines were available as discrete, whole-line additions, meaning each line was either fully built or not built at all. All other inputs around generation, fuel, and demand assumptions were identical to the core cases, as documented in the inputs section of this report.

The results detailed in Table 12 show that none of the candidate transmission lines were selected as economically viable in the Domestic Market Only case, while all candidate lines were built in the All Markets with High Hydrogen load case. These outcomes indicate that interprovincial transmission provides value in transformative scenarios that integrate large quantities of offshore wind, and that are meaningfully constrained by existing transmission limits between the provinces. A detailed examination of how expanded transmission capacity affects dispatch dynamics including hourly flows, curtailment profiles, and capacity factor changes is presented in the Hourly Production Cost (Economic Dispatch) Analysis section of this report.

Table 12. Transmission Expansion Results

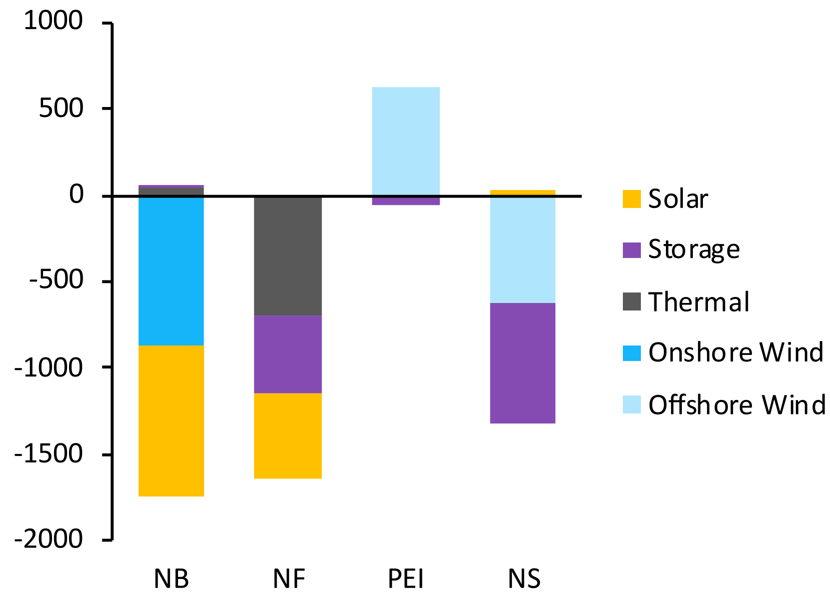
Candidate Transmission Expansion Project	Year Built (Domestic Market Only Case)	Year Built (All Markets Case)	Added Line Capacity (MW)
Nova Scotia <> New Brunswick	Not Selected	2035	860
New Brunswick <> Prince Edward Island	Not Selected	2035	560
Nova Scotia <> Newfoundland & Labrador	Not Selected	2041	1,250

Impacts on Resource Portfolios

Transmission expansion between provinces provides investment value by: a) enabling greater interprovincial sharing, displacing the need for investment in some local capacity while maintaining reliability standards; and b) enabling selection of resources located in valuable areas that may otherwise be limited by their ability to export to neighboring provinces. The All Markets with High Hydrogen transmission expansion case showed substantial portfolio impacts compared to the core case. Figure 24 illustrates the magnitude of these effects by the year 2050, where positive values indicate an increase and negative indicate a decrease in capacity relative to the core case without the transmission expansion.

Reduced builds of onshore wind, solar, and storage indicate the ability of the provinces to rely on interprovincial transfers rather than investing in local capacity. New Brunswick, Newfoundland & Labrador, and Nova Scotia each see significant reductions in installed capacity from solar, onshore wind, thermal, and storage when interprovincial transmission expansion is enabled. There is also a shift of about 600 MW of offshore wind from Nova Scotia to Prince Edward Island, reflecting a reallocation of development toward locations with marginally lower LCOE. This shift decreases Nova Scotia's total offshore wind capacity from about 10.5 GW to about 9.9 GW and increases Prince Edward Island's from about 1.0 GW to about 1.6 GW. The system benefits of that shift likely stem from improved ability to help serve New Brunswick loads in this expanded transmission future.

Figure 24. All Markets 2050 Change in Installed Capacity (MW) with Transmission Expansion

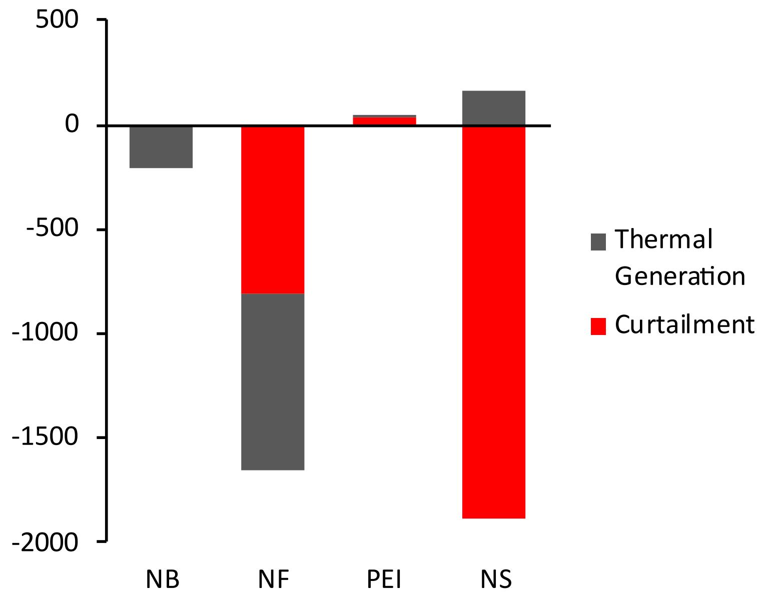


Impacts on Generation

New transmission also provides operational value by enabling provinces to displace higher-cost thermal dispatch with lower-cost imports and to reduce curtailment. Figure 25 illustrates the magnitude of these changes in the All Markets with High Hydrogen transmission expansion case. Positive values indicate an increase in generation relative to the core case and negative values indicate a decrease in the transmission expansion case relative to the core case.

Newfoundland & Labrador and Nova Scotia each see curtailment reductions of approximately 750 GWh and 1,900 GWh respectively. New Brunswick and Newfoundland & Labrador see significant reductions in thermal generation of approximately 200 GWh and 850 GWh respectively. The mechanics of how expanded transmission drives these outcomes—including hourly flows, curtailment profiles, and capacity factor changes—are examined in detail in the Hourly Production Cost (Economic Dispatch) Analysis section of this report.

Figure 25. All Markets 2050 Change in Generation and Curtailment (GWh) with Transmission Expansion



Hourly Production Cost (Economic Dispatch) Analysis

This economic dispatch analysis builds on the long-term capacity expansion assessment by evaluating the same market opportunity scenarios, but re-dispatching those resulting portfolios at an hourly level across a full year of weather conditions. Narrative in this section focuses on the "All Markets – High Hydrogen" scenario, as it represents the highest offshore wind penetration and so most clearly illustrates the operational dynamics observed. However, many of the trends discussed appear in the lower deployment scenarios as well but in a more muted manner.

Three characteristic operating weeks are used to help explain system behavior: (1) a week with high wind and high load, (2) a week with prolonged low-wind conditions ("wind lulls"), and (3) a week with high-curtailment conditions. Together, these weeks demonstrate the operational realities of a wind-dominant system:

+ During **high wind and high load** conditions, interprovincial trade across existing interties and export capability enable large volumes of offshore wind to be absorbed with limited curtailment.
+ During **multi-day wind lulls**, reliability depends on low-capacity-factor gas-fired generation and power sharing between the Atlantic provinces. These periods are infrequent but operationally critical.
+ During **high-curtailment** periods, lower seasonal load combined with strong wind output and limited transfer capability between provinces leads to economically driven curtailment, highlighting the importance of transmission capacity both within the Atlantic Provinces and with neighboring markets.

In addition to the above core case dynamics, E3 also evaluated the transmission expansion sensitivities discussed previously in the production cost model. Consistent with the capacity expansion findings, this analysis showed that in the most transformative future scenarios, expanded interprovincial transfer capability can materially reduce curtailment and displace thermal generation by redistributing offshore wind more efficiently. In these cases, some curtailment persists due to external market conditions, indicating that both physical and economic constraints shape outcomes, but it is reduced relative to the cases without transmission expansion. However, in lower deployment scenarios, expanded inter-provincial transmission yields minimal operational benefits. This indicates that deployment scale is an important factor when considering such transmission investments.

Overall, the results demonstrate that at high levels of offshore wind penetration, the system still operates reliably across the full set of weather conditions experienced during the year.[37] This includes many periods where renewable generation serves the majority of daily (and in some cases, weekly) loads, but also some periods where dispatchable generation is required for reliability. Additionally, demand access remains a key factor for offshore wind utilization, as illustrated in the transmission expansion cases. This section profiles each of these findings, along with dispatch dynamics across each of the Atlantic provinces. Additional cross-scenario comparisons and case results are provided in the Appendix.

Results Overview

To evaluate how dispatch responds to changing weather and system conditions, we use a two-step approach that moves from a high-level screening view to detailed operational analysis.

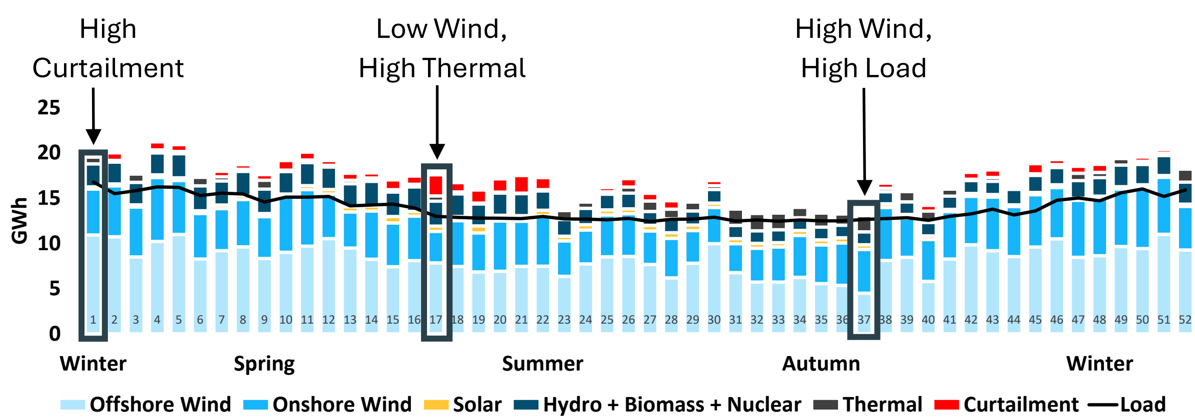
First, we aggregate hourly dispatch results to the weekly level for each snapshot year and scenario. Weekly aggregations sum total generation across load and major generation technology categories including solar, onshore wind, offshore wind, and a combined category of all oil and gas-fired thermal resources, and a combined category of hydroelectric generation, biomass, and nuclear. It also aggregates total curtailed generation from renewable resources. The weekly view provides a concise picture of how output, curtailment, and thermal generation shift over time and allows us to identify representative or extreme operating periods. We screen for weeks with:

- High or low offshore wind generation
- High thermal generation
- High renewable curtailment
- High system load

[37] Importantly, this analysis is conducted at the zonal level, and so this reliability confirmation is related to overall resource adequacy in each province under hourly dispatch constraints. This does not examine sub-zonal constraints or investment needs; those were assessed as part of the "Preliminary Atlantic Canada Transmission Expansion Needs Analysis to Integrate Offshore Wind," which can be accessed on the study homepage here: https://netzeroatlantic.ca/research/atlantic-canada-offshore-wind-grid-integration-and-transmission-study

This step highlights periods where notable patterns emerge. Figure 26 illustrates the weekly screening results in the All Markets, High Hydrogen scenario and highlights the periods selected for detailed hourly analysis. In this chart, the region-wide hourly generation results are aggregated to weekly totals by generation technology categories. These include offshore wind, onshore wind (labeled "wind"), solar, a group of aggregated hydropower, biomass, and nuclear generation, total thermal generation (inclusive of gas and oil-fired generation), imports from external regions like Quebec and New England, and curtailed generation. The curtailment category is technology agnostic and is made up of a combination of generation curtailed from offshore wind, onshore wind, and solar.

Figure 26. Weekly Dispatch Aggregation and Selected Analysis Periods for All Markets Case 2050



We then examine selected weeks at an hourly resolution to examine the underlying drivers of dispatch outcomes. The hourly view allows us to observe when transmission constraints bind, how reserve requirements influence commitment decisions, how import/export price signals shift flows, and how load and renewable variability interact with operational limits. In this way, the weekly aggregation identifies periods of interest, while the hourly analysis reveals the specific constraints and parameters shaping system behavior. Examples of these hourly views are shown in subsequent sections.

There is a substantial volume of hourly dispatch data[38] across study scenarios, snapshot years, and the three characteristic weeks evaluated. To provide a clear and focused discussion, this results section focuses on the 2050 All Markets, High Hydrogen case, which models the highest level of

[38] These data are all available in the public database, accessible via the following link: https://netzeroatlantic.ca/research/atlantic-canada-offshore-wind-grid-integration-and-transmission-study

offshore wind penetration and therefore most clearly illustrates system dynamics[39] by showing weeks when offshore wind generation is at its highest, lowest, and most curtailed. Importantly, the use of this case to discuss operational dynamics does not indicate that this development future is viewed as any more likely than the other scenarios. Rather, since this case contains the most significant supply and demand changes relative to today's system, it is useful for illustrating the dynamics of a wind heavy system, dynamics that are present—but less noticeable—in all cases that model offshore wind development. Dispatch charts for other scenarios and years evaluated are included in the appendix.

Select features of the All Markets – High Hydrogen case include:

- Substantial domestic load growth via electrification of buildings and transportation and the development of a large-scale hydrogen production capacity[40]
- The addition of a large capacity High-Voltage Direct Current (HVDC) intertie between Nova Scotia and ISO New England
- The development of 16.5 GW of offshore wind capacity by 2050 to help serve these new and expanded market demands

The following results summaries detail hourly results for the 2050 All Markets – High Hydrogen scenario across three characteristic weeks:

- January 1–7 (High Wind and High Load)
- September 10–16 (Low Wind Lull and High Thermal Generation)
- April 23–29 (High Curtailment)

This results discussion focuses first on dispatch dynamics in the absence of expanded inter-provincial transmission between provinces in Atlantic Canada. However, in the High Curtailment with Transmission Expansion section, we also examine how dispatch during the April 23–29 high-curtailment week shifts with expanded inter-provincial transmission capacity.

Hourly dispatch graphics use similar generation groupings as the weekly generation charts but with hourly resolution and aggregated at the provincial level. These graphics also include a few additional categories. A solid black line represents total load including hydrogen electrolysis before it is enabled to flex up and down in response to price signals. A dashed line reflects load with electrolysis flexibility. Electrolysis flexibility characteristics are detailed in the Input Assumptions section. When

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[39] It is worth noting that in focusing the results discussion on this case, we are unable to explore several interesting system changes that happen across the cases. An example of this is Prince Edward Island shifting from a net importer (the current dynamic and finding in low offshore wind deployment cases) to a net exporter as offshore wind reaches higher levels of penetration. Similarly, across model years in many cases Newfoundland & Labrador shifts from a predominantly hydroelectric system to a more diversified wind-hydro mix. Results showing these and additional cross-case dynamics are provided in the Appendix.

[40] Though assumed to be hydrogen electrolysis load growth in this study, these serve as a proxy for any large industrial load additions in the region. Additional scenario design details, including the specific load growth and New England intertie assumptions, are detailed at length in the Phase 1 report, available here: https://netzeroatlantic.ca/sites/default/files/2026-01/phase_1_report_market_opportunities_atlantic_canada_offshore_wind_250609_1.pdf

the dashed line is above the solid line, hydrogen demand has increased; when it falls below, hydrogen load has decreased. If the dashed line is not visible, hydrogen is either not present in that province, or it is not actively modifying its load during that period.

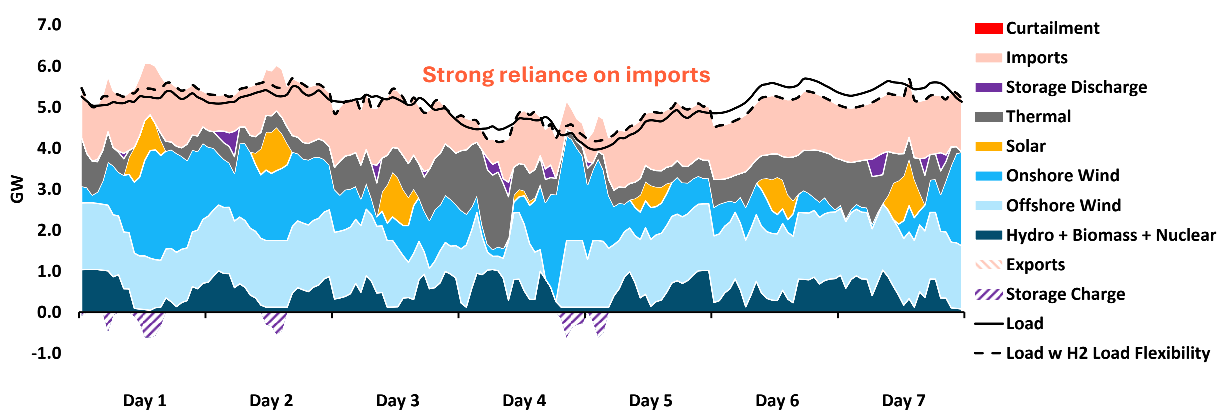
Unlike the weekly charts, the hourly graphics display gross imports and exports as well as storage behavior. At the weekly level, external market exchanges are shown as a single net import value and battery charging and discharging largely offset each other aside from efficiency losses. In the hourly charts, imports are shown as positive generation and exports as negative values. Similarly, storage charging is shown as positive, while discharging is shown as negative.

High Wind and High Load Conditions (January 1-7)

We begin with the week of January 1–7 in the 2050 All Markets High Hydrogen case, which represents the highest offshore wind deployment and therefore most clearly illustrates system-wide operational dynamics. Across provinces, hourly dispatch occurring in this week reflects high offshore wind output, interprovincial trade, and high levels of load under winter peak conditions.

New Brunswick. During periods when load is elevated and wind output is high, New Brunswick relies heavily on imports. Over this week, imports are sourced from a combination of Prince Edward Island, Nova Scotia, and Québec. This reflects New Brunswick's role as a transmission hub, balancing strong regional wind production with local load obligations through intertie utilization.

Figure 27. New Brunswick Hourly Dispatch, All Markets Case, High Wind Week, January 1-7, 2050

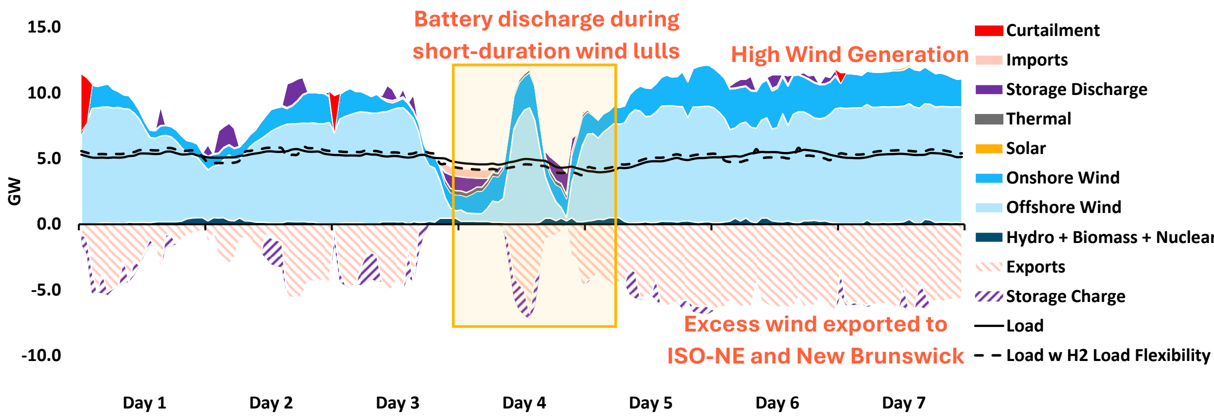


Note: In this scenario, total installed capacities in New Brunswick are 2,000 MW of offshore wind, 3,349 MW of onshore wind, 1,396 MW of solar, 2,812 MW of thermal resources, 618 MW of battery storage, 919 MW of hydro, and 124 MW of Biomass.

Nova Scotia. The combination of offshore and land-based wind exceeds 10 GW at peak during this week which even in this rapid growth future is approximately double provincial load. Despite this substantial overgeneration, curtailment remains limited. The limited curtailment reflects that the system is able to absorb most wind output through exports to New Brunswick and across the ISO-NE intertie, demonstrating the importance of export capability in integrating high levels of offshore wind.

Separately, the yellow box highlights two short-duration wind lulls at the beginning and end of Day 4. During these periods, New Brunswick is also a net importer and the import transmission constraint from Newfoundland & Labrador is binding, leading Nova Scotia to rely on battery dispatch to meet loads.

Figure 28. Nova Scotia Hourly Dispatch, All Markets Case, High Wind Week, January 1-7, 2050

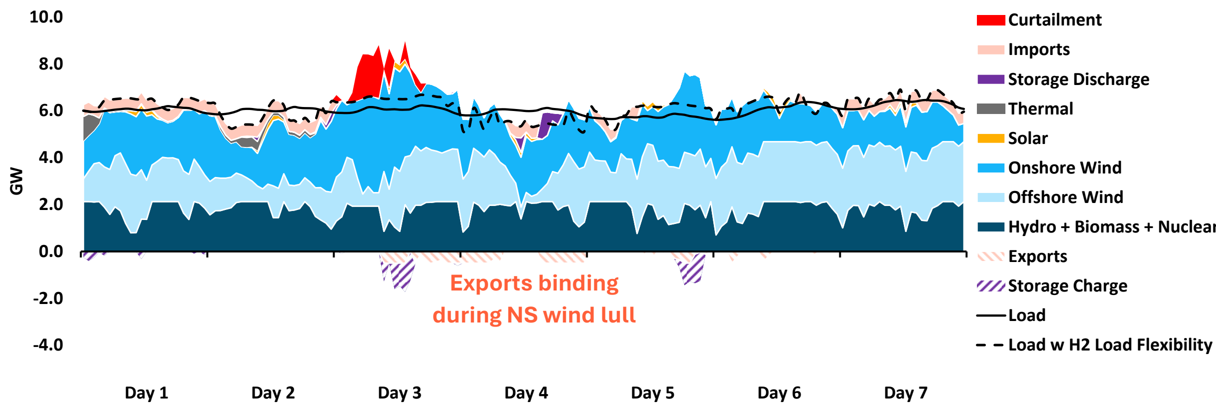


Note: In this scenario, total installed capacities in Nova Scotia are 10,471 MW of offshore wind, 3,651 MW of onshore wind, 223 MW of solar, 1,599 MW of thermal resources, 1,996 MW of battery storage, 392 MW of hydro, and 93 MW of biomass.

Newfoundland & Labrador. In contrast to its present-day hydro-dominated profile, Newfoundland & Labrador in 2050 exhibits a more diversified mix of hydro, land-based wind, and offshore wind. During hours of coincident peak load and offshore wind generation, the system is largely able to accommodate available wind output without significant curtailment, indicating sufficient internal flexibility and transmission capability during this representative winter week.

As previously discussed, during Nova Scotia's short term wind lulls on Day 4, Newfoundland & Labrador is hitting the 500 MW maximum export constraint, causing Nova Scotia to rely on battery dispatch.

Figure 29. Newfoundland & Labrador Hourly Dispatch, All Markets Case, High Wind Week, January 1-7, 2050

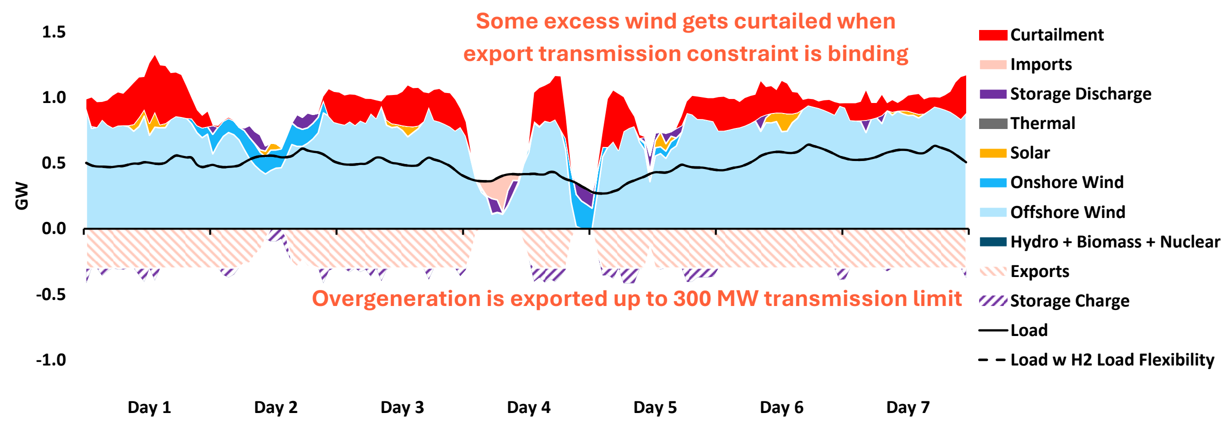


Note: In this scenario, installed capacity in Newfoundland & Labrador totals 3,000 MW of offshore wind, 6,027 MW of onshore wind, 559 MW of solar, 1,131 MW of thermal resources, 1,232 MW of battery storage, and 2,126 MW of hydro.

Prince Edward Island. Prince Edward Island emerges as a predominantly exporting province in this scenario, building substantial offshore wind capacity primarily to serve demand both within-province and in New Brunswick. However, exports in this scenario are limited by the 300 MW transmission capability between PEI and New Brunswick.[41] In the hourly chart, exports (shown below the x-axis) reach this 300 MW limit during high-wind periods but cannot exceed it. When offshore wind generation continues to increase after the export interface is fully utilized, the excess energy results in curtailment. As a result, even during periods of elevated load, curtailment occurs when the export constraint binds. This transmission-limited dynamic becomes more pronounced during periods of system-wide high wind and curtailment discussed later in this section.

[41] Note that inter-provincial transmission expansion is explored in subsequent scenario evaluations, as discussed in Section “High Curtailment with Transmission Expansion”

Figure 30. Prince Edward Island Hourly Dispatch, All Markets Case, High Wind Week, January 1-7, 2050



Note: In this scenario, total installed capacities in Prince Edward Island include 1,029 MW of offshore wind, 342 MW of onshore wind, 272 MW of solar, 214 MW of thermal resources, and 114 MW of battery storage.

Overall, this week illustrates how, under high offshore wind deployment, system behavior is increasingly shaped by transmission availability, export opportunities, and flexible hydrogen demand, rather than by local load alone.

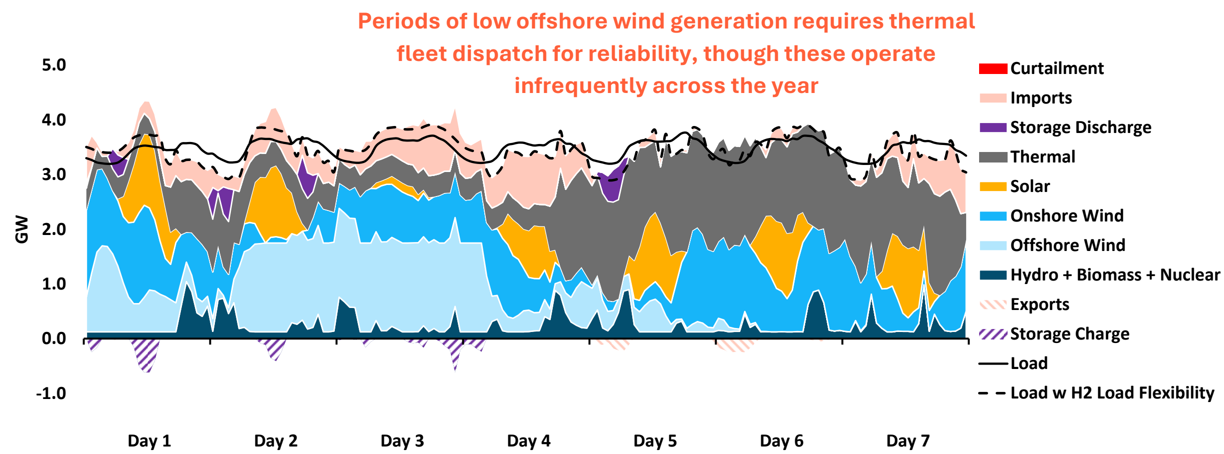
High Thermal Resource Generation (September 10-16)

The week of September 10–16 represents a sustained low-wind period, often referred to as a wind lull. Offshore wind generation is significantly reduced across provinces for multiple consecutive days, requiring dispatchable thermal resources to come online to maintain reliability. In deeply decarbonized systems with high wind penetration, multi-day wind lulls present a key reliability risk, as electricity must be supplied by firm resources or imports when renewable output is limited.

In this scenario, the thermal fleet consists primarily of natural gas–fueled combined-cycle gas turbines (CCGTs) and combustion turbines (CTs) that are built largely to meet reliability needs in a wind-dominant system. These units operate at very low annual capacity factors with CCGTs operating at less than 10% over the year, compared to traditional baseload generators that typically exceed 60%. This week illustrates the conditions under which these low-capacity-factor reliability resources are relied upon to serve load.

New Brunswick. As offshore wind output declines both within New Brunswick and in neighboring provinces, New Brunswick cannot rely on the same level of imports observed in high-wind weeks. In the latter half of the week, in-province offshore wind generation falls to near zero, and thermal generation increases accordingly to meet demand.

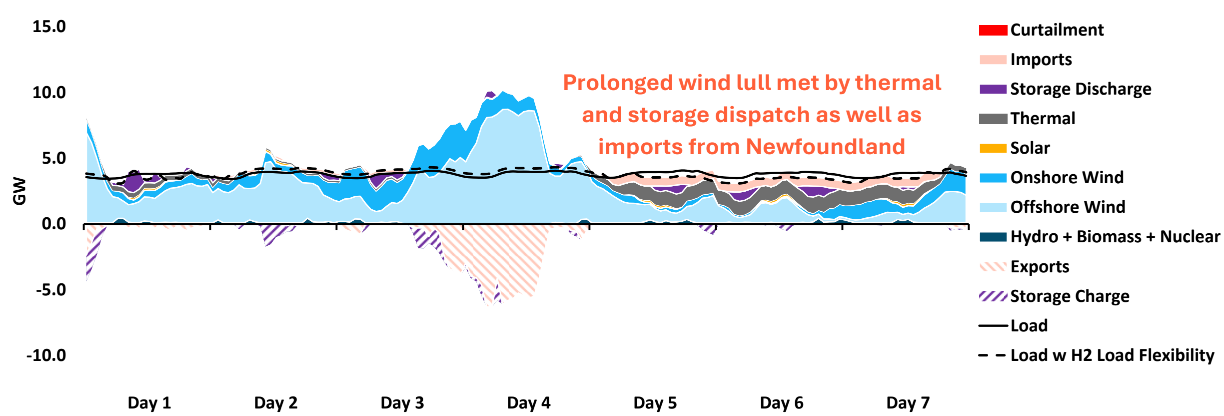
Figure 31. New Brunswick Hourly Dispatch, All Markets Case, High Thermal Week, September 10-16, 2050



Note: In this scenario, total installed capacities in New Brunswick are 2,000 MW of offshore wind, 3,349 MW of onshore wind, 1,396 MW of solar, 2,812 MW of thermal resources, 618 MW of battery storage, 919 MW of hydro, and 124 MW of Biomass.

Nova Scotia. During the wind lull in the latter half of the week, offshore wind generation is significantly reduced. During this time, a substantial amount of thermal generation comes online, and battery storage is discharged to meet demand. Nova Scotia also relies on steady imports from Newfoundland & Labrador up to the 500 MW import limit during this lull, reflecting inter-provincial balancing under low-wind conditions.

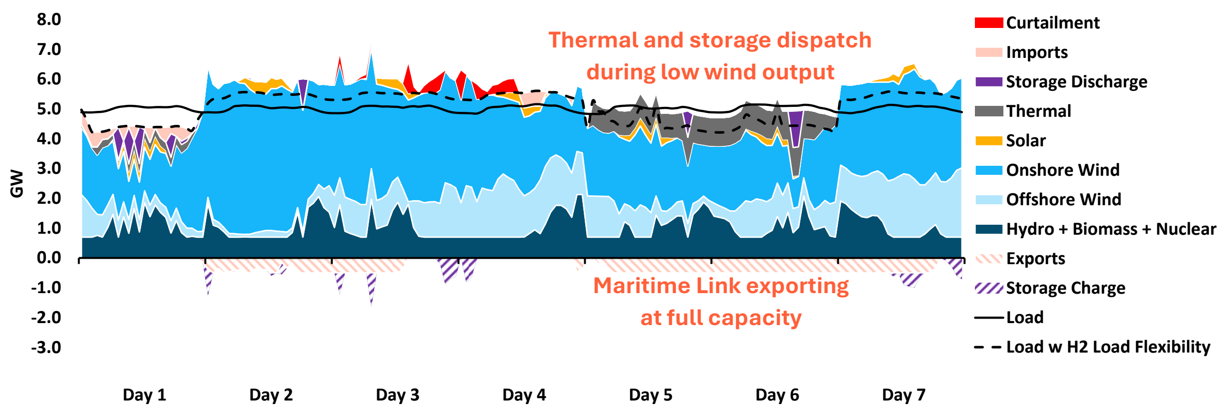
Figure 32. Nova Scotia Hourly Dispatch, All Markets Case, High Thermal Week, September 10-16, 2050



Note: In this scenario, total installed capacities in Nova Scotia are 10,471 MW of offshore wind, 3,651 MW of onshore wind, 223 MW of solar, 1,599 MW of thermal resources, 1,996 MW of battery storage, 392 MW of hydro, and 93 MW of biomass.

Newfoundland & Labrador. Similar to Nova Scotia, Newfoundland & Labrador brings thermal generation online during this period that were largely offline during the high-wind weeks. Additionally, given the geographic scale of this region, offshore wind in Newfoundland & Labrador does have some diversity benefit relative to the wind generation timing in the rest of the region; constrained export capacity limits the benefits of this diversity but could provide benefits in a future with additional transmission investment to Nova Scotia.

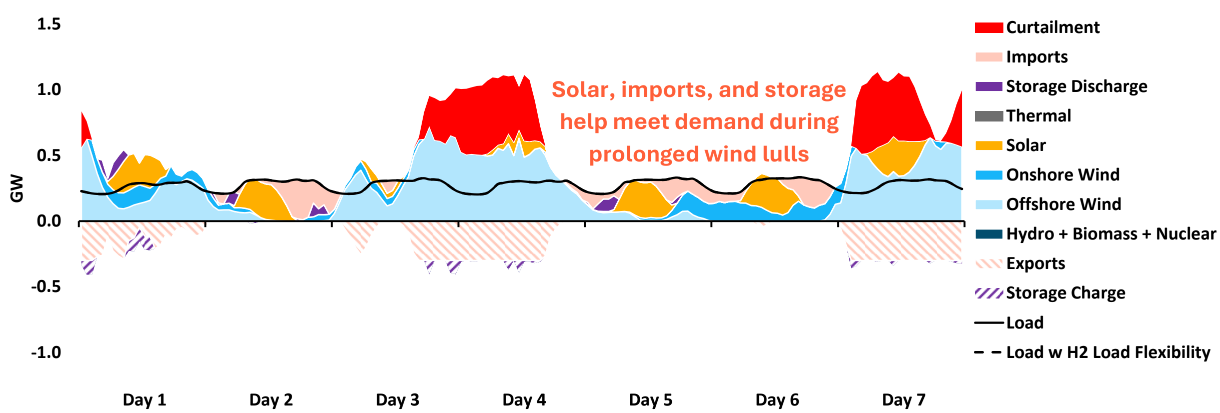
Figure 33. Newfoundland & Labrador Hourly Dispatch, All Markets Case, High Thermal Week, September 10-16, 2050



Note: In this scenario, total installed capacities in Newfoundland & Labrador are 3,000 MW of offshore wind, 6,027 MW of onshore wind, 559 MW of solar, 1,131 MW of thermal resources, 1,232 MW of battery storage, and 2,126 MW of hydro.

Prince Edward Island. Prince Edward Island, which has a relatively higher proportion of solar compared to other provinces, sees solar generation partially offset low wind output during daylight hours. During non-solar hours, PEI relies on imports and thermal generation from New Brunswick to meet demand. This pattern underscores the complementary role of solar during daytime wind lulls, while also illustrating the continued need for dispatchable or imported resources during evening and overnight periods.

Figure 34. Prince Edward Island Hourly Dispatch, All Markets Case, High Thermal Week, September 10-16, 2050



Note: In this scenario, total installed capacities in Prince Edward Island include 1,029 MW of offshore wind, 342 MW of onshore wind, 272 MW of solar, 214 MW of thermal resources, and 114 MW of battery storage.

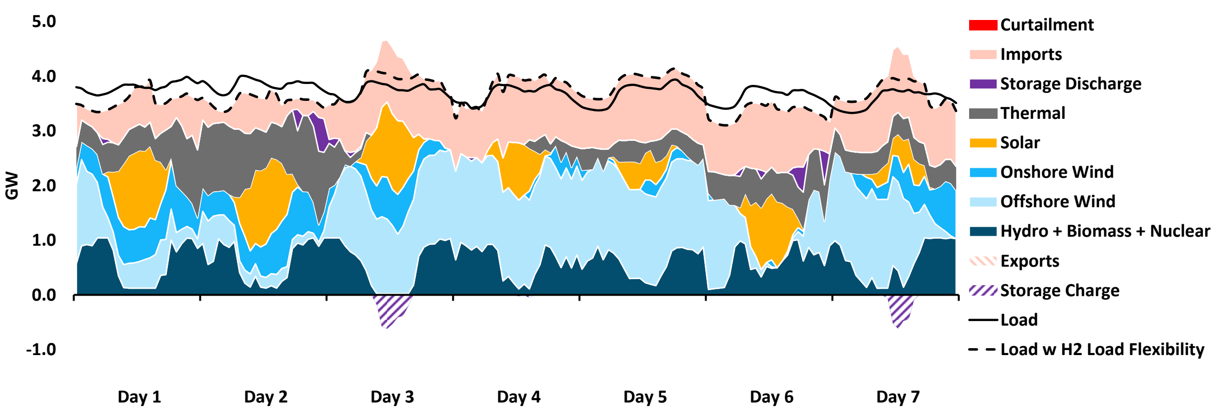
Overall, this week demonstrates that while offshore wind provides substantial energy during favorable conditions, reliability during prolonged wind lulls depends on low-capacity-factor thermal resources and interprovincial trade. These periods are infrequent but operationally critical in high-renewable systems.

High Curtailment Conditions (April 23-29)

The week of April 23–29 represents a high-curtailment period in the 2050 All Markets High Hydrogen case. Relative to January, system loads are lower across provinces, while offshore wind output remains strong. This combination of high renewable availability and more moderate spring load creates sustained periods where export capability and market conditions determine whether wind generation is exported or curtailed.

New Brunswick. Operationally, this week does not differ substantially from the January high-wind week in terms of New Brunswick's dispatch structure; curtailment pressures are primarily observed in other provinces. This is a result of both the portfolio mix in New Brunswick in this case in 2050, and transmission wheeling capability with neighboring markets.

Figure 35. New Brunswick Hourly Dispatch, All Markets Case, High Curtailment Week, April 23-29, 2050

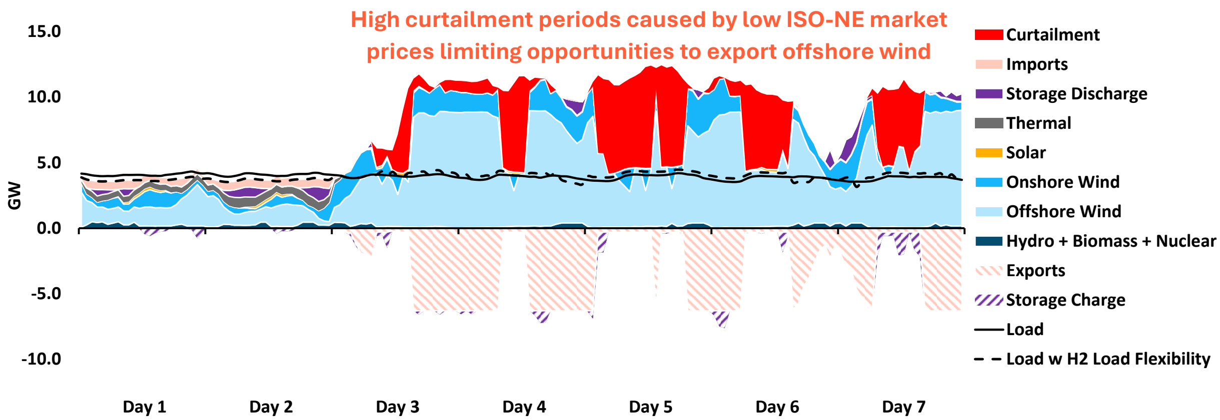


Note: In this scenario, total installed capacities in New Brunswick are 2,000 MW of offshore wind, 3,349 MW of onshore wind, 1,396 MW of solar, 2,812 MW of thermal resources, 618 MW of battery storage, 919 MW of hydro, and 124 MW of Biomass.

Nova Scotia. Offshore wind generation ramps up beginning in the evening of April 25th (Day 3) and remains elevated through the end of the week. Two key dynamics emerge once wind output increases. First, Nova Scotia exports significant volumes of electricity, primarily to ISO-NE via the subsea HVDC cables added as part of this scenario construct. During these periods, exports reach the transmission interface limit, visible in the chart as flatlined exports below the x-axis. Even after export capability is fully utilized, wind generation that exceeds the combination of provincial load and available export capacity results in curtailment, shown as red bands at the top of the wind stack.

Second, there are periods when Nova Scotia reduces or ceases exports to ISO-NE and instead curtails multiple gigawatts of wind. These instances, visible as wider red bands in the dispatch graphic, correspond to periods when ISO-NE market prices fall below the level at which exports from Nova Scotia are economic. When exports are no longer financially viable, energy is curtailed despite available transmission capacity, highlighting the interaction between market price signals and physical system limits.

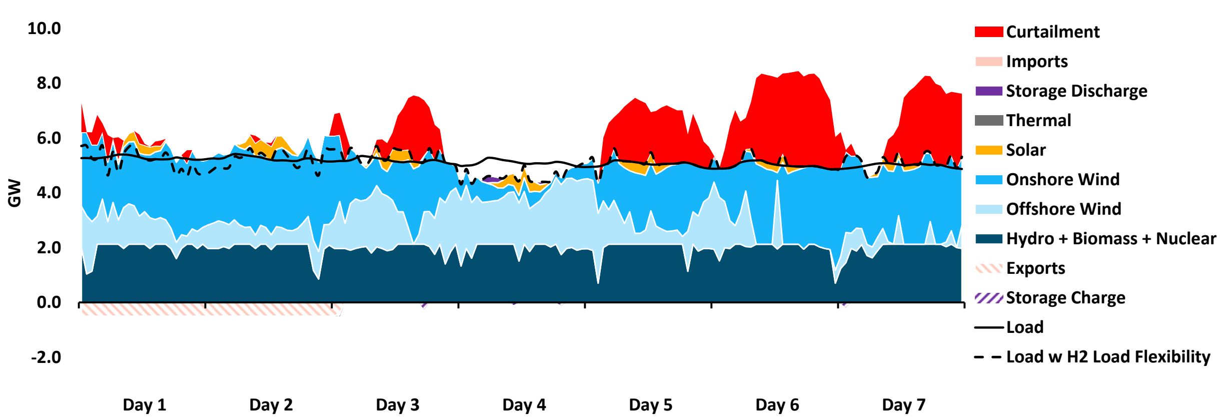
Figure 36. Nova Scotia Hourly Dispatch, All Markets Case, High Curtailment Week, April 23-29, 2050



Note: In this scenario, total installed capacities in Nova Scotia are 10,471 MW of offshore wind, 3,651 MW of onshore wind, 223 MW of solar, 1,599 MW of thermal resources, 1,996 MW of battery storage, 392 MW of hydro, and 93 MW of biomass.

Newfoundland & Labrador. Provincial load declines from approximately 6 GW in January to around 5 GW in April. High wind and hydro output during this lower-load period lead to curtailment, as available renewable generation exceeds internal demand and export opportunities.

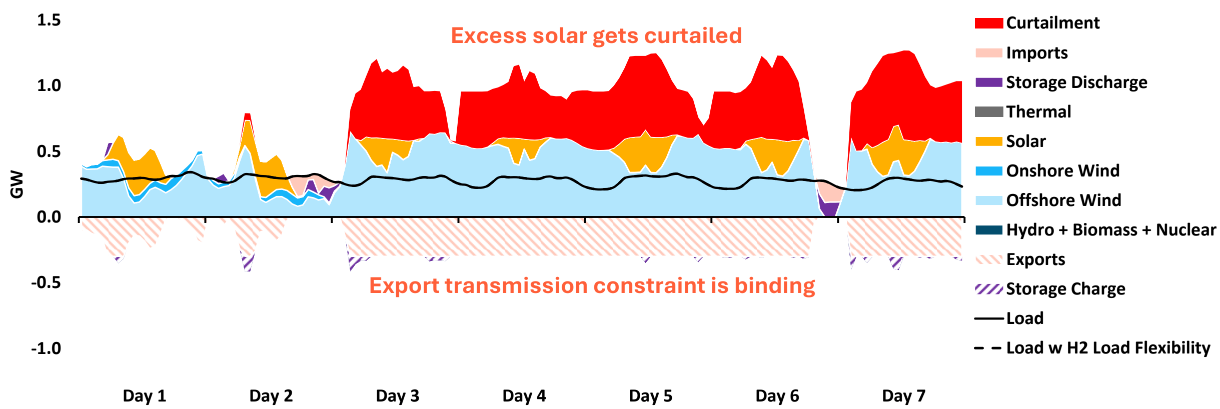
Figure 37. Newfoundland & Labrador Hourly Dispatch, All Markets Case, High Curtailment Week, April 23-29, 2050



Note: In this scenario, total installed capacities in Newfoundland & Labrador are 3,000 MW of offshore wind, 6,027 MW of onshore wind, 559 MW of solar, 1,131 MW of thermal resources, 1,232 MW of battery storage, and 2,126 MW of hydro.

Prince Edward Island. As in January, Prince Edward Island exports up to the 300 MW transmission limit to New Brunswick. However, with lower provincial load and sustained offshore wind output in April, there is even more excess wind available once the 300 MW export interface is saturated, resulting in more pronounced curtailment than observed in the high-wind, high-load January week.

Figure 38. Prince Edward Island Hourly Dispatch, All Markets Case, High Curtailment Week, April 23-29, 2050



Note: In this scenario, total installed capacities in Prince Edward Island include 1,029 MW of offshore wind, 342 MW of onshore wind, 272 MW of solar, 214 MW of thermal resources, and 114 MW of battery storage.

Together, this week illustrates that in lower-load conditions, curtailment is driven by a combination of overgeneration, physical transmission constraints, and external market price dynamics.

High Curtailment with Transmission Expansion

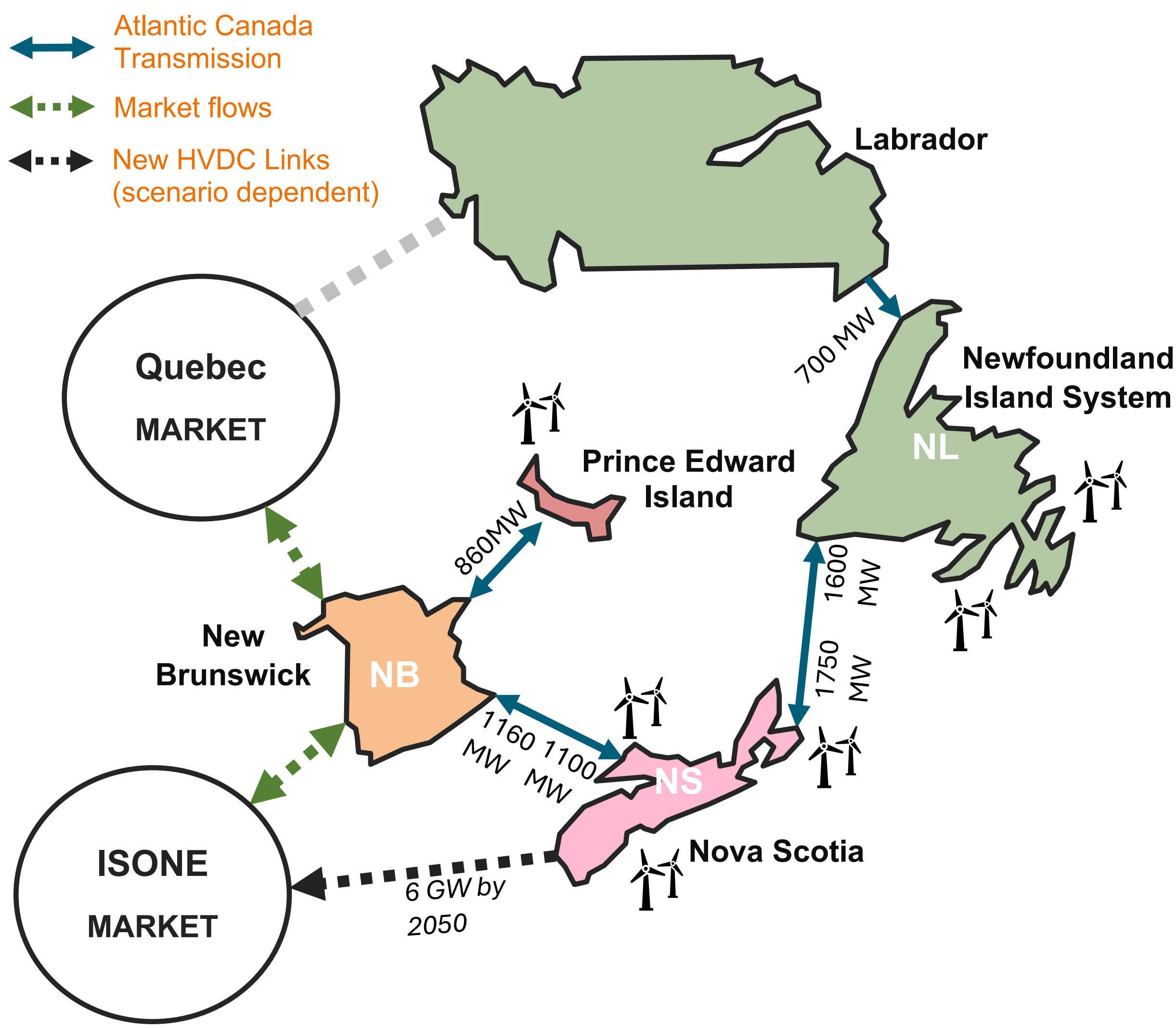
This subsection re-examines dispatch graphics across select weeks in each of the four Atlantic Canada provinces under the transmission expansion case to assess how increased interprovincial transfer capability alters observed dispatch dynamics. All generation, fuel, hydrogen, and demand assumptions are identical to the 2050 All Markets – High Hydrogen case[42]; however, the model includes the following incremental transmission additions:

[42] It is critical to note that, unlike the dynamics observed in the core case analysis, the transmission expansion findings are specific to this All Markets, High Hydrogen future. It is only in such a transformative scenario that transmission additions are selected economically in the capacity modeling, and that operational benefits are significant. This analysis was also performed for the C1: Domestic Markets only case and found that at those levels of offshore wind additions and load growth, these hypothetical transmission additions are not selected economically, and dispatch benefits are minimal. This finding illustrates that interprovincial transmission expansion benefits are really tied to scale, and so potential investment in those solutions will hinge on how the region evolves in the coming years.

+ 560 MW between Prince Edward Island and New Brunswick
+ 860 MW between New Brunswick and Nova Scotia
+ 1,250 MW between Nova Scotia and Newfoundland & Labrador

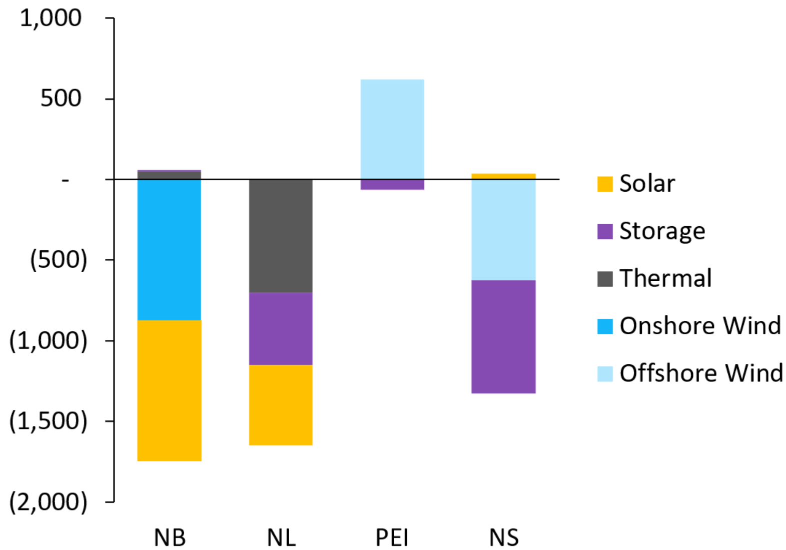
The resulting regional topology in this case is detailed in Figure 39 below.

Figure 39. Regional Topology by 2050 in All Markets, High Hydrogen Case with Transmission Expansion



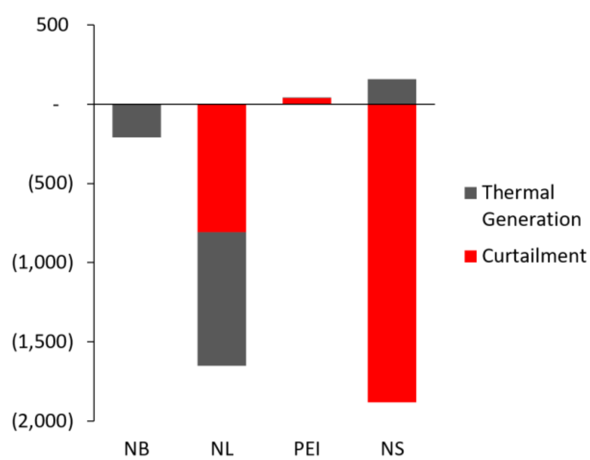
These expanded interfaces enable greater reliance on interprovincial exchanges to meet loads leading to reductions in builds of onshore wind, thermal generation, battery storage, and solar. These changes also allow offshore wind generation to be built in provinces where it is most economically valuable. Figure 40 shows how installed capacities changed with the increased interprovincial transmission.

Figure 40. All Markets 2050 Change in Installed Capacity (MW) with Transmission Expansion



The operational results further demonstrate how transmission expansion shifts key cost drivers visible in dispatch dynamics. Increased transfer capability reduces curtailment that previously occurred when binding interprovincial transmission constraints limited the sharing of excess wind generation. At the same time, greater access to lower-cost renewable imports displaces higher-cost thermal generation during critical hours, lowering fuel consumption and overall production costs. Figure 41 quantifies these changes, showing reductions in both curtailment and thermal generation when transmission expansion is enabled. Together, these results illustrate how relieving transmission constraints alters both investment outcomes and short-run operational cost drivers.

Figure 41. All Markets 2050 Change in Generation and Curtailment (GWh) with Transmission Expansion

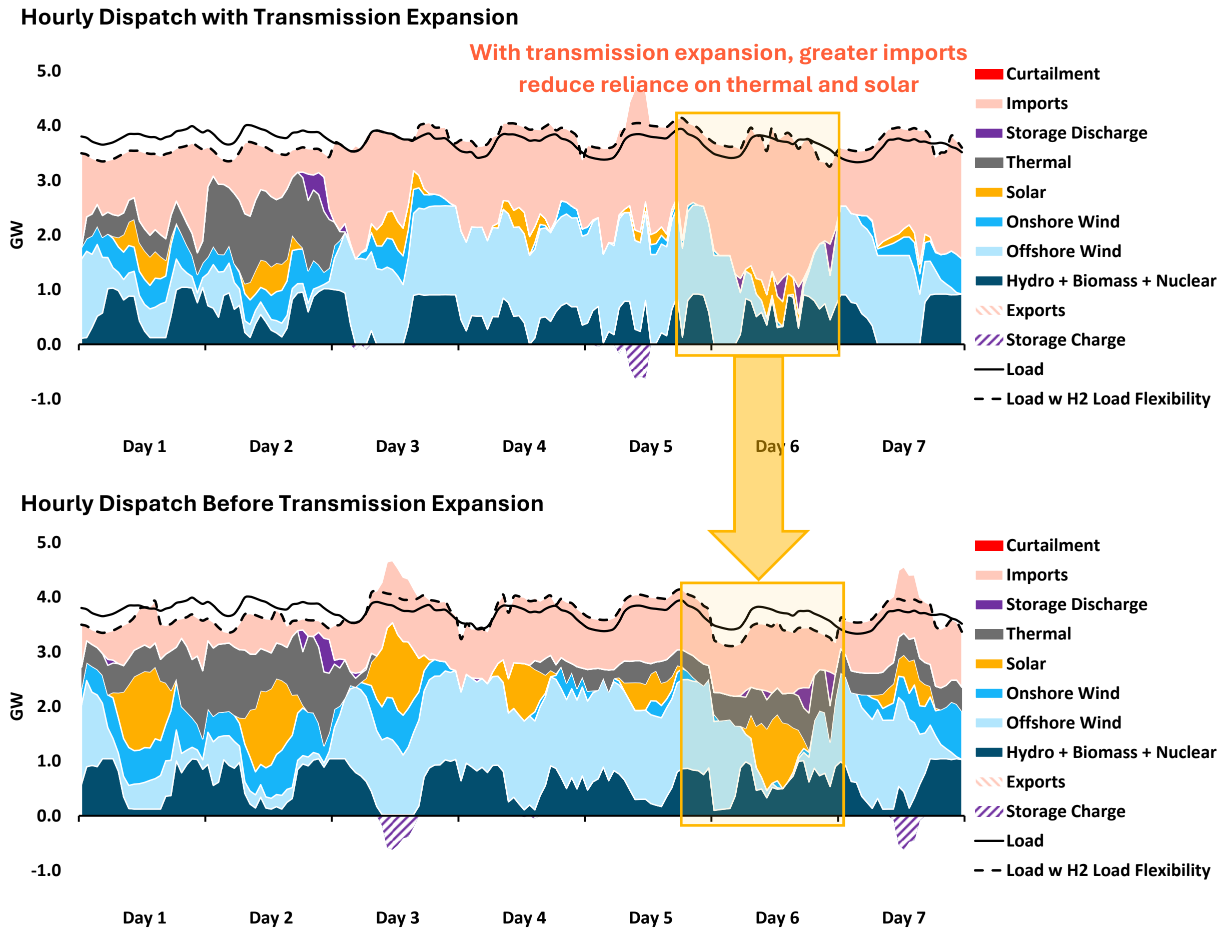


To clearly illustrate the operational impacts of transmission expansion, we compare hourly dispatch outcomes for the April 23–29 week with and without the additional interprovincial transfer capability.

Viewing the same representative week under both configurations isolates the effect of expanded transmission on dispatch behavior.

New Brunswick (High Curtailment Week). During the high-curtailment week, Day 6 clearly illustrates how expanded import capability reduces reliance on in-province resources. With greater transfer capacity, New Brunswick imports additional offshore wind from Prince Edward Island and Nova Scotia, displacing thermal and solar generation that was required in the non-expansion case.

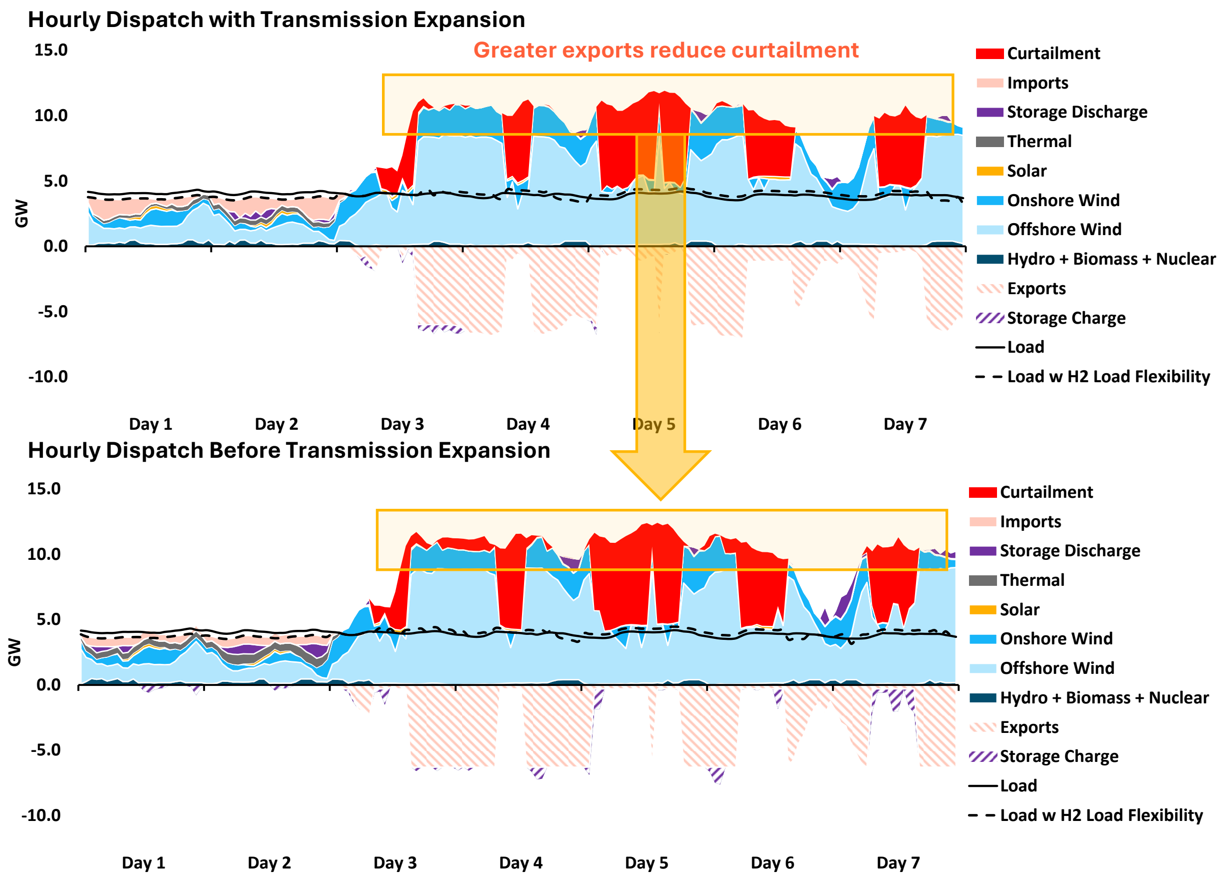
Figure 42. New Brunswick Hourly Dispatch, All Markets Case with and without Transmission Expansion, High Curtailment Week, April 23-29, 2050



Note: In New Brunswick, the transmission expansion scenario led to decreases relative to the core All Markets with High Hydrogen scenario in onshore wind from 3,349 MW to 2,474 MW, and solar from 1,396 MW to 524 MW. There were slight increases in thermal resources from 2,812 MW to 2,863 MW and batteries from 618 MW to 625 MW. Offshore wind, hydro, and biomass capacities were unchanged at 2,000 MW, 919 MW, and 124 MW respectively.

Nova Scotia (High Curtailment Week). Two distinct dynamics are at play during this week. The evident dynamic remains the ISO-NE price signal: when external market prices are weak, exports become uneconomic and significant volumes of wind are curtailed despite available physical transmission capacity. This dynamic remains. However, during this week, there is still a reduction of 42 GWh of curtailment when the expanded transmission is introduced. This is due to the improved export capabilities to New Brunswick and Newfoundland enabling excess wind to be exported to neighboring provinces rather than curtailed due to previously binding interprovincial constraints. While this export-driven relief is smaller in magnitude than the ISO-NE price effect, it still reduces curtailed wind in Nova Scotia significantly over the course of the week. Together, these results show that although market conditions remain the primary driver of curtailment, relieving interprovincial transmission constraints meaningfully increases the share of wind that can be delivered regionally instead of spilled.

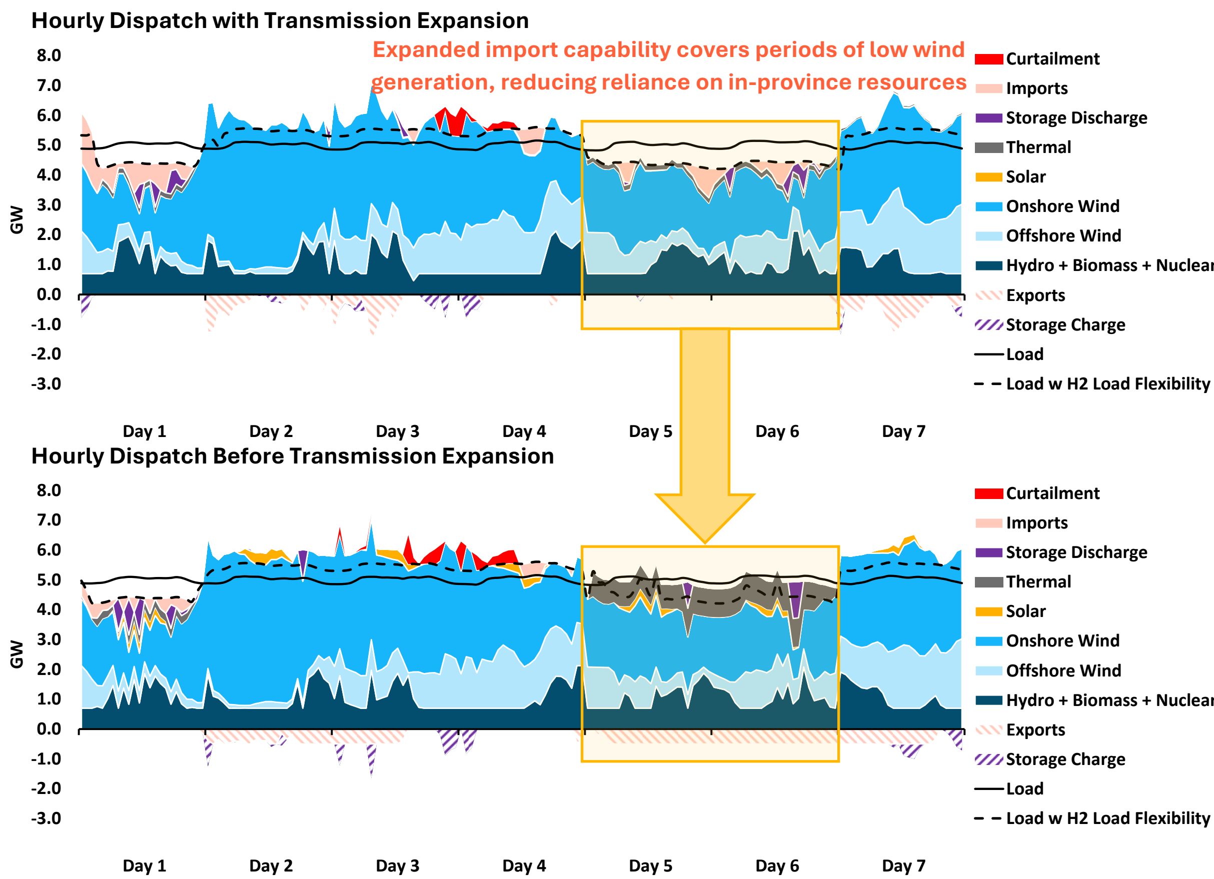
Figure 43. Nova Scotia Hourly Dispatch, All Markets Case with and without Transmission Expansion, High Curtailment Week, April 23-29, 2050



Note: In Nova Scotia, the transmission expansion scenario led to decreases relative to the core All Markets with High Hydrogen scenario in offshore wind from 10,471 MW to 9,848 MW, and battery storage from 1,996 MW to 1,294 MW. There was a slight increase in solar from 223 MW to 257 MW. Onshore wind, thermal resources, hydro, and biomass capacities were unchanged at 3,651 MW, 1,599 MW, 392 MW, and 93 MW respectively.

Newfoundland & Labrador (High Thermal Week). During the high-thermal dispatch week, the role of Newfoundland & Labrador shifts under the transmission expansion case. In the non-expansion configuration, Nova Scotia was constrained in its ability to import from New Brunswick and therefore relied more heavily on imports from Newfoundland & Labrador during the prolonged wind lull in days 5 and 6, even as thermal resources were dispatched locally. With the additional New Brunswick–Nova Scotia transfer capability, Nova Scotia can now access imports from both New Brunswick and Newfoundland & Labrador simultaneously. This increased flexibility reduces the need for in-province thermal generation, solar, and battery discharge during peak hours of the lull. As a result, reliance on thermal resources declines relative to the non-expansion case, demonstrating how expanded transmission enables more efficient regional balancing during low-wind conditions.

Figure 44. Newfoundland & Labrador Hourly Dispatch, All Markets Case with and without Transmission Expansion, High Thermal Week, September 10-16, 2050

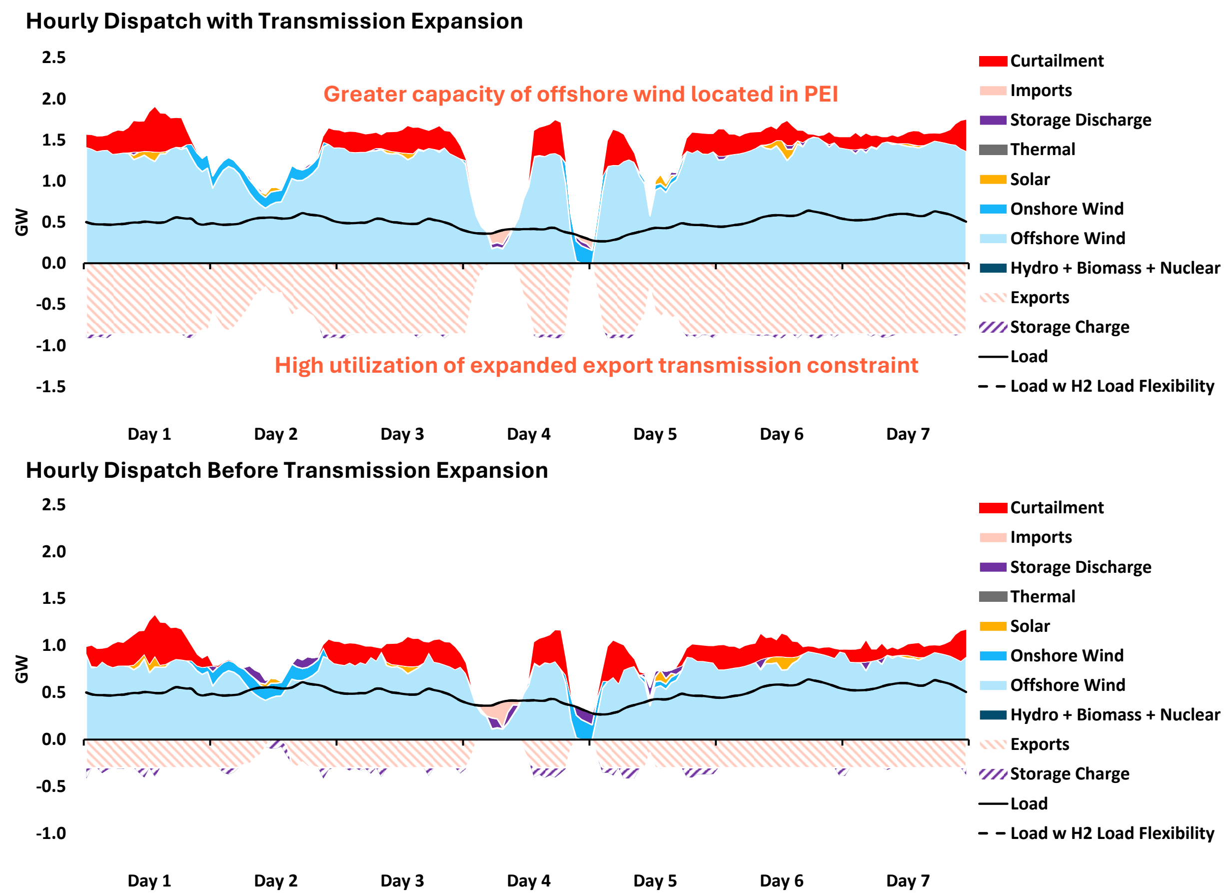


Note: In Newfoundland & Labrador, the transmission expansion scenario led to decreases relative to the core All Markets with High Hydrogen scenario in solar from 559 MW to 62 MW, thermal resources from 1,131 MW to 338 MW, and battery storage from 1,232 MW to 781 MW. Offshore wind, onshore wind, and hydro capacities were unchanged at 3,000 MW, 6,027 MW, 2,126 MW.

Prince Edward Island. The expanded interface between Prince Edward Island and New Brunswick allows for greater offshore wind development and higher export volumes. In the dispatch graphic, exports extend well beyond the previous 300 MW limit, clearly illustrating the increased transfer capability. With higher export limits, a larger share of offshore wind generation is delivered to New

Brunswick rather than curtailed, significantly reducing excess energy relative to the non-expansion case.

Figure 45. Prince Edward Island Hourly Dispatch, All Markets Case with and without Transmission Expansion, High Wind Generation Week, January 1-7, 2050



Note: In Prince Edward Island, the transmission expansion scenario led to decreases relative to the core All Markets with High Hydrogen scenario in battery storage from 114 MW to 52 MW and an increase in offshore wind from 1,029 MW to 1,652 MW. Onshore wind, solar, and thermal resources were unchanged at 342 MW, 272 MW, and 214 MW respectively.

Overall, the transmission expansion case demonstrates that incremental interprovincial capacity can materially reduce curtailment and thermal reliance by redistributing offshore wind generation more efficiently across the region, at least in such a transformative future as the All Markets, High Hydrogen scenario. At the same time, it highlights that not all curtailment is transmission-driven, as external market price signals from ISO-NE continue to shape dispatch decisions. Lower deployment scenarios do not see the same inter-provincial transmission benefits[43], indicating that potential

[43] Operational analysis results of the transmission expansion assessment conducted on the C1: Domestic Markets only scenario are provided in the Appendix.

investments in these resources will depend on how the power sector in the region evolves in the coming years.

Conclusion

The analysis presented in this report underscores both the scale of the challenge and the breadth of opportunity facing the Atlantic Canadian provinces as they move toward deep decarbonization and consider new development opportunities, including offshore wind. National climate commitments, calling for substantial emissions reductions by 2030 and economy-wide net-zero emissions by mid-century, are not incremental targets. They imply a structural shift in how electricity is generated, delivered, and consumed. Within this broader transition, the Atlantic Provinces occupy a distinctive position: a region with meaningful remaining fossil generation, rapidly evolving demand, and access to some of the most promising offshore wind resources on the eastern seaboard. This study considered both the deployment barriers and market drivers that could enable development of a substantial offshore wind industry.

Across all modeled futures, a consistent theme emerges: offshore wind has the technical capability to supply a significant share of regional electricity needs while materially reducing reliance on fossil fuels. This is particularly important during winter months, when electricity demand peaks and system stress is highest. The alignment between offshore wind production profiles and seasonal demand patterns further enhances its energy and capacity value.

At the same time, offshore wind remains a high cost resource, and introduces a variety of integration and deployment challenges:

- Offshore wind projects involve higher upfront capital expenditures than land-based alternatives, reflecting both the size of the equipment and the complexity of constructing and operating in marine environments.
- The relatively early stage of the offshore wind sector in North America introduces additional uncertainty, including longer development timelines and evolving regulatory frameworks. While global experience (particularly in Europe) demonstrates that costs can decline over time through innovation and accumulated expertise, achieving similar progress in Atlantic Canada will require deliberate investment and sustained commitment.
- Offshore wind isn't feasible to develop at a small scale; to establish this industry and bring down costs, a substantial volume must be developed, which could present integration challenges in a region with relatively low peak demand needs.
- The existing grid in the Atlantic Provinces was not designed to accommodate large volumes of geographically concentrated renewable generation, nor to facilitate substantial power transfers between provinces or to external markets. As offshore wind deployment increases, these limitations become more pronounced, leading to congestion and curtailment if not addressed.

However, beyond meeting domestic needs, the study highlights the strategic importance of Atlantic Canada's offshore wind resource in a broader regional context. Neighboring jurisdictions, including the Northeastern United States and other Canadian provinces, are facing similar pressures: rising electricity demand, tightening emissions constraints, and increasing difficulty in siting new infrastructure. In that environment, high-capacity-factor offshore wind located relatively close to major load centers becomes especially valuable. The scenarios explored here illustrate how the Atlantic Provinces could play a larger role as a supplier of clean energy, supporting decarbonization efforts beyond their borders. However, realizing this opportunity is not simply a function of resource availability. It depends on the ability to move power across jurisdictions, which introduces both technical and institutional complexity. Transmission expansion, whether within the region or across interties, emerges as a central enabling factor, requiring coordination, long-term planning, and alignment across multiple stakeholders.

The potential interaction between offshore wind development and emerging industrial demand further expands the scope of opportunity. Large new loads, such as those associated with green hydrogen production or data-intensive industries, represent both a challenge and a catalyst for system planning. On one hand, they significantly increase electricity requirements, adding to the urgency of capacity expansion. On the other, they can provide a stable source of demand that supports investment in new generation resources. The modeling results suggest a mutually reinforcing dynamic: the availability of abundant, clean electricity from offshore wind can attract industrial development, while sustained industrial demand can justify larger-scale deployment of offshore wind capacity. This relationship is not without uncertainty, particularly given the early stage of markets such as green hydrogen production, but it points to a pathway in which energy system transformation and economic development are closely linked.

Operational insights from the production cost analysis further emphasize the evolving nature of grid management in a system with high levels of wind generation. Periods of abundant offshore wind output can meet a large share of demand, but they also introduce the possibility of overgeneration when supply exceeds local consumption and export capability. Conversely, intervals of low wind output require rapid response from dispatchable resources to maintain system balance. Managing these dynamics will require not only physical infrastructure, such as transmission and flexible generation, but also advanced operational practices, improved forecasting, and potentially new market mechanisms. Curtailment, while an inherent feature of high-renewable systems, can be reduced through better integration across a wider geographic footprint, reinforcing the value of interprovincial and cross-border coordination.

Taken together, the findings of this study point toward a set of interconnected conclusions. First, offshore wind represents a high potential resource for Atlantic Canada, capable of supporting emissions reductions, meeting growing electricity demand, and contributing to regional energy security. Second, the scale of its impact depends heavily on complementary investments; in transmission, in firm capacity, and in the broader enabling environment required to bring projects to fruition. Third, the benefits of offshore wind extend beyond the power sector, offering opportunities to support industrial development and participate in emerging clean energy markets. Finally, the path forward is inherently uncertain, but the scale of potential benefits to the Atlantic Canadian provinces from exploring this resource is sufficiently large as to warrant ongoing analysis and exploration.

In this context, planning for offshore wind cannot occur in isolation. It must be embedded within a comprehensive strategy that considers the full electricity system, the timing of demand growth, and the interplay between local and external markets. Early actions—whether in the form of pilot projects, transmission upgrades, or policy frameworks, can help reduce uncertainty, build institutional capacity, and position the region to take advantage of future opportunities. As the Atlantic Provinces navigate this transition, the choices made in the near term will shape not only the trajectory of the power sector, but also the region's role in a decarbonizing North American energy landscape.

Appendix A. Additional Detailed Results

The following presents selected additional results from the capacity expansion modeling. Additional visualizations and data outputs are available through visual graphic interface and public database.[44]

A.1. Province Specific Findings

New Brunswick

New Brunswick, as the largest energy load center among the Atlantic Provinces and a hub for regional interconnectivity, exhibits distinct dynamics in electricity generation and installed capacity under varying scenarios aimed at achieving Canada's decarbonization targets. In Figure 46 and Figure 47, E3 shows a summary of New Brunswick modeling results for generation and installed capacity, respectively.

In modeled scenarios, wind emerges as a critical driver for decarbonization, with offshore wind capacity and generation bolstering growing onshore wind significantly over time. By 2050, scenarios illustrate potential futures in which offshore wind supports domestic electricity demand, facilitates export opportunities, and enables the development of a nascent hydrogen economy. The high-capacity factors of offshore wind, particularly during winter peak periods, make it a robust resource for addressing growing electrification loads and the retirement of fossil-fueled capacity.

Total installed capacity in New Brunswick increases markedly across scenarios to accommodate rising electricity demands. This, combined with generation dynamics, reflects a shift from fossil fuels toward renewables and imports. While traditional fossil-based generation like coal and gas diminishes across scenarios, onshore wind, offshore wind and imports from Nova Scotia, HQ, and Prince Edward Island, play pivotal roles. Imports help balance regional supply-demand dynamics and enable efficient integration of offshore wind.

New Brunswick's energy landscape under these scenarios highlights the critical role of offshore wind, regional flows, and infrastructure development in achieving ambitious decarbonization targets while meeting growing electricity and hydrogen demands.

[44] These are hosted by Net Zero Atlantic, accessible via the study page here: https://netzeroatlantic.ca/research/atlantic-canada-offshore-wind-grid-integration-and-transmission-study

Figure 46. New Brunswick Generation (GWh) Across All Scenarios

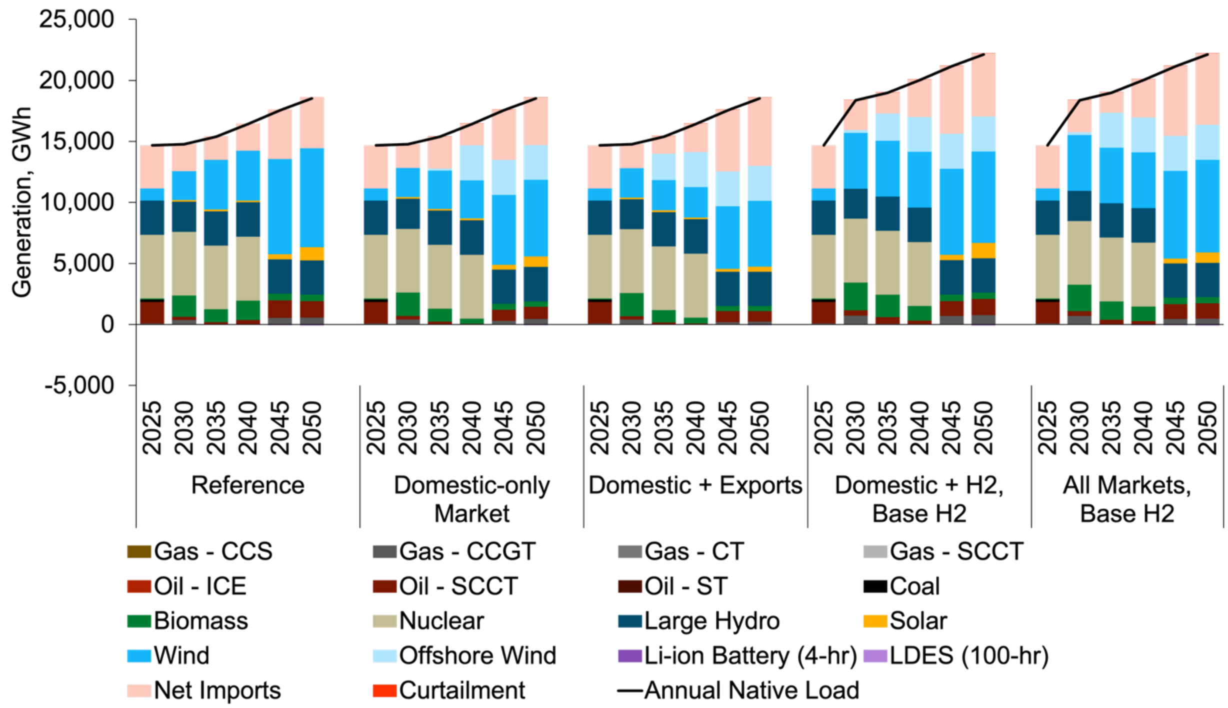
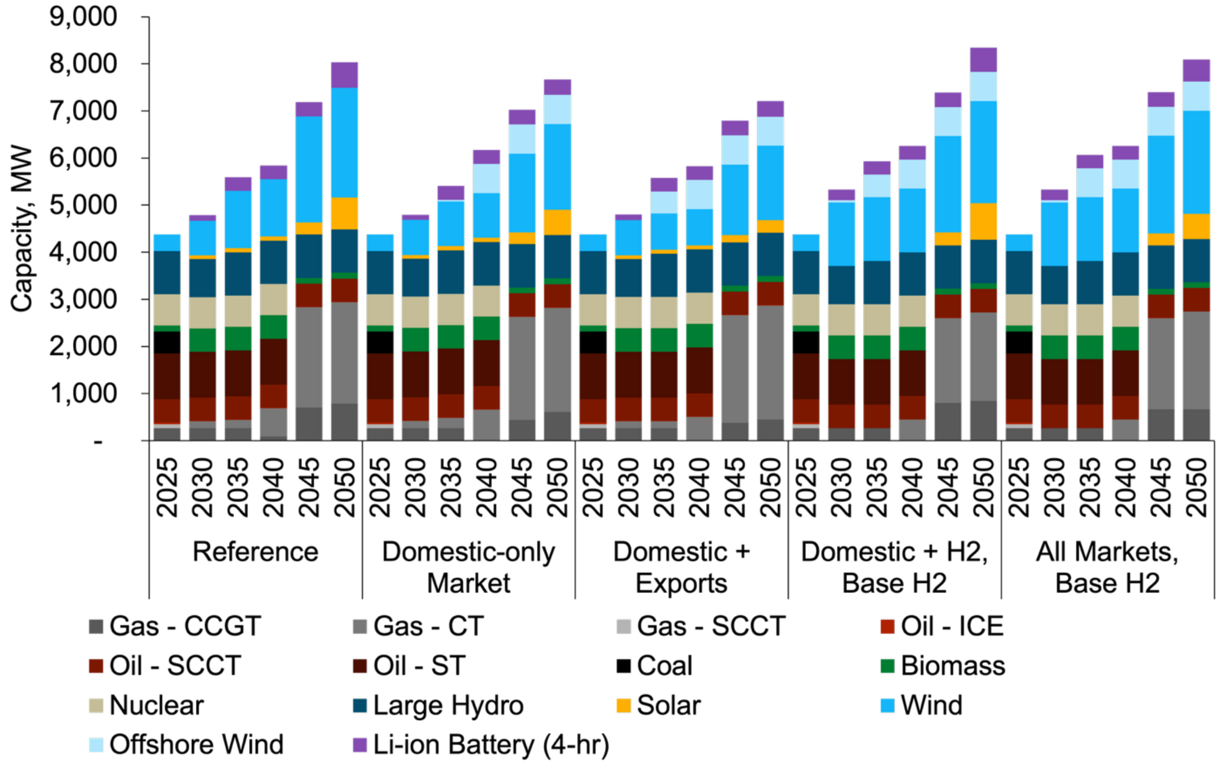


Figure 47. New Brunswick Installed Capacity (MW) Across All Scenarios



Nova Scotia

Nova Scotia's energy generation and capacity evolve significantly under the modeled scenarios to explore pathways to decarbonization, emphasizing offshore wind integration, increased exports, and hydrogen production. Figure 48 shows the generation in Nova Scotia and Figure 49 shows the installed capacity in Nova Scotia for select model years across all scenarios. These results of the modeled scenarios highlight the potential of offshore wind in meeting domestic demand and participating in export markets while supporting net-zero goals.

Offshore wind is a central component of decarbonization efforts, with substantial capacity additions modeled in non-reference scenarios. By 2050, offshore wind capacity exceeds 6 GW in scenarios prioritizing hydrogen and export markets. Offshore wind generation scales to meet increasing domestic demand, including peak winter loads, and provides a high-quality, zero-emissions resource for export markets, particularly ISO-NE.

Offshore wind also supports hydrogen production in the Domestic + H2 and All Markets scenarios, driving a significant portion of energy demand by mid-century. By 2050, a significant portion of the hydrogen load is met through offshore wind, reflecting its potential as a decarbonization pathway for heavy industry and transportation sectors.

Curtailment of renewable resources emerges as a challenge during high-output periods, reflecting the need for enhanced storage, grid balancing, and increased inter-regional transmission capacity.

Under the modeled scenarios, Nova Scotia emerges as a significant exporter of clean electricity, driven by its high-quality offshore wind resources. By 2050, significant offshore wind capacity supports exports primarily to New Brunswick and the ISO-NE market. Offshore wind's seasonal stability, with high winter capacity factors, aligns well with peak demand in New England and complements New Brunswick's existing generation mix. The potential for enhanced transmission infrastructure between Nova Scotia, New Brunswick, and ISO-NE could enable further export growth, addressing transmission congestion and curtailment challenges.

Installed capacity diversifies significantly, with substantial growth in offshore wind, battery storage and other renewables by 2050. Fossil fuel capacity decreases, driven by retirements and emissions reduction goals, with remaining gas generation serving as a peaking resource.

The analysis underscores the valuable role offshore wind could play in decarbonizing Nova Scotia's electricity system, fostering export opportunities, and supporting emerging hydrogen industries, while highlighting the challenges of cost, infrastructure, and system integration.

Figure 48. Nova Scotia Generation (GWh) Across All Scenarios

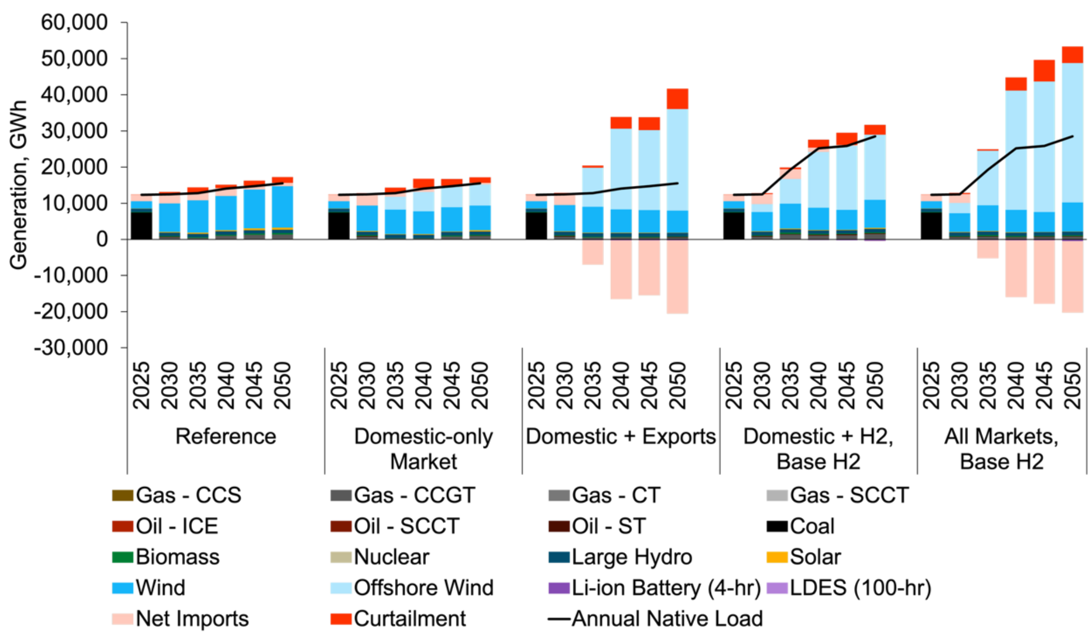
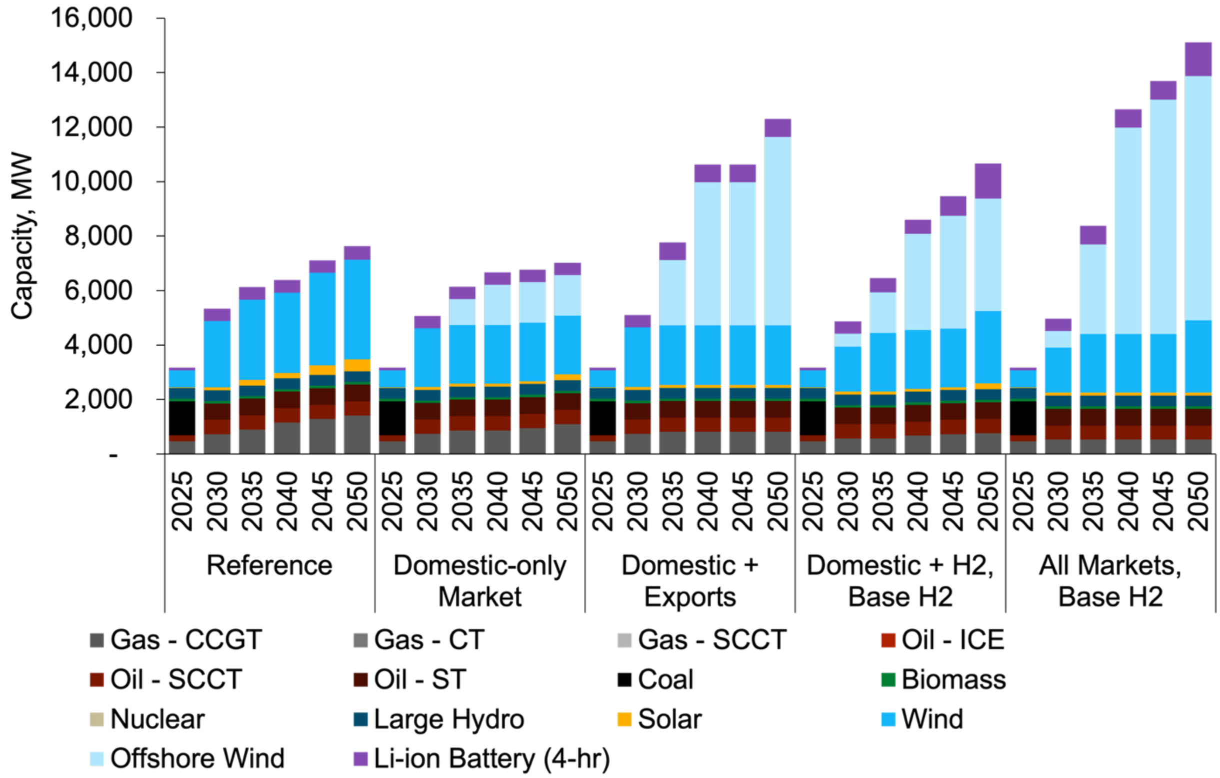


Figure 49. Nova Scotia Installed Capacity (MW) Across All Scenarios



Newfoundland & Labrador

Newfoundland & Labrador (NL), modeled with a focus on its island system of Newfoundland, exhibits a unique energy transition influenced by the abundant hydro resources modeled in Labrador that can be partially accessed by the island system through the Labrador-Island Link (LIL). The combined generation across the province is shown in Figure 50 and the installed capacity is shown in Figure 51.

Newfoundland's electricity generation remains heavily dominated by hydro resources across all scenarios. The LIL enables Labrador's extensive hydro capacity from Muskrat Falls and Churchill Falls to support both the Island's and broader province's energy needs and export opportunities. Fossil fuel generation, including oil and gas, plays a limited role in the generation mix, consistent with decarbonization goals and the availability of clean hydroelectric power. Offshore wind contributes modestly to generation in later years of modeled scenarios. Offshore wind capacity grows primarily to serve domestic load growth and augment exports to regional markets.

NL's Hydro surplus and emerging offshore wind capacity enable it to act as a net exporter of clean energy to neighboring regions. The presence of substantial hydro capacity, combined with transmission limits described above, results in some curtailment in high-renewable scenarios.

Newfoundland & Labrador's energy system dynamics are shaped by its hydro dominance, the critical role of the Labrador-Island Link, and emerging contributions from offshore wind.

Figure 50. Newfoundland & Labrador Generation (GWh) Across All Scenarios

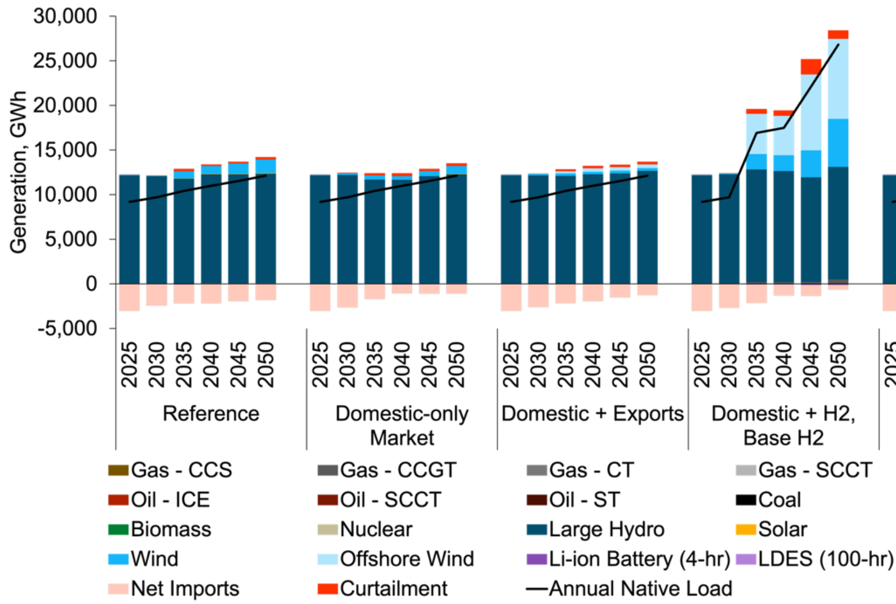
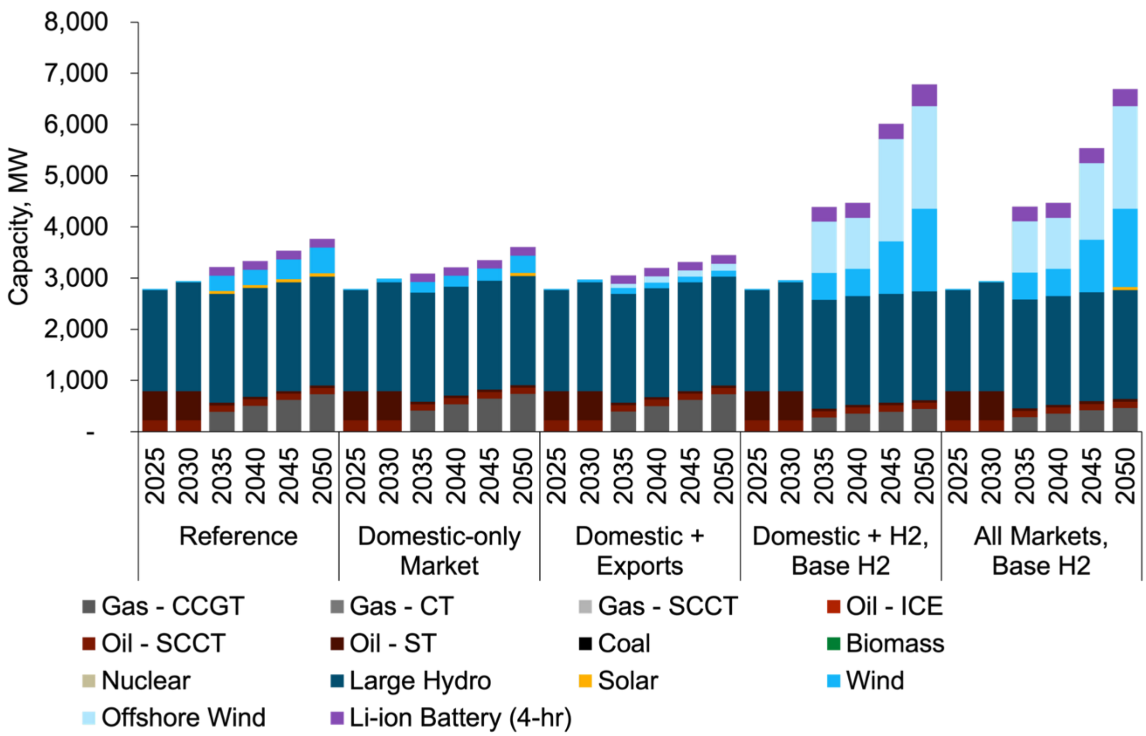


Figure 51. Newfoundland & Labrador Installed Capacity (MW) Across All Scenarios



Prince Edward Island

Prince Edward Island (PEI), with the smallest electricity load among the Atlantic Provinces, demonstrates unique energy system dynamics driven by its reliance on imports and renewable generation. Results for generation and installed capacity in Prince Edward Island are shown in Figure 52 and Figure 53, respectively.

PEI's domestic electricity generation remains relatively small across scenarios, with significant reliance on imported electricity to meet local demand. This dynamic persists even as renewable generation increases in later years. Offshore wind does not play as prominent of a role in the local generation or installed capacity of PEI, but a lot of generation is imported from New Brunswick. Capacity expansion in PEI is primarily geared toward onshore wind. The island's heavy dependence on imports underscores the importance of its interconnection with New Brunswick. These imports complement local renewable generation, particularly during periods of low wind output. Fossil-fuel-based capacity remains negligible in PEI's scenarios, reflecting the province's renewable energy focus and limited domestic demand. Increased renewable capacity leads to instances of curtailment, particularly in high-generation scenarios. This highlights the importance of transmission and storage solutions to optimize resource use.

Prince Edward Island's energy transition emphasizes renewable energy development, especially wind, and relies heavily on imports and regional collaboration to meet demand and integrate clean energy resources.

Figure 52. Prince Edward Island Generation (GWh) Across All Scenarios

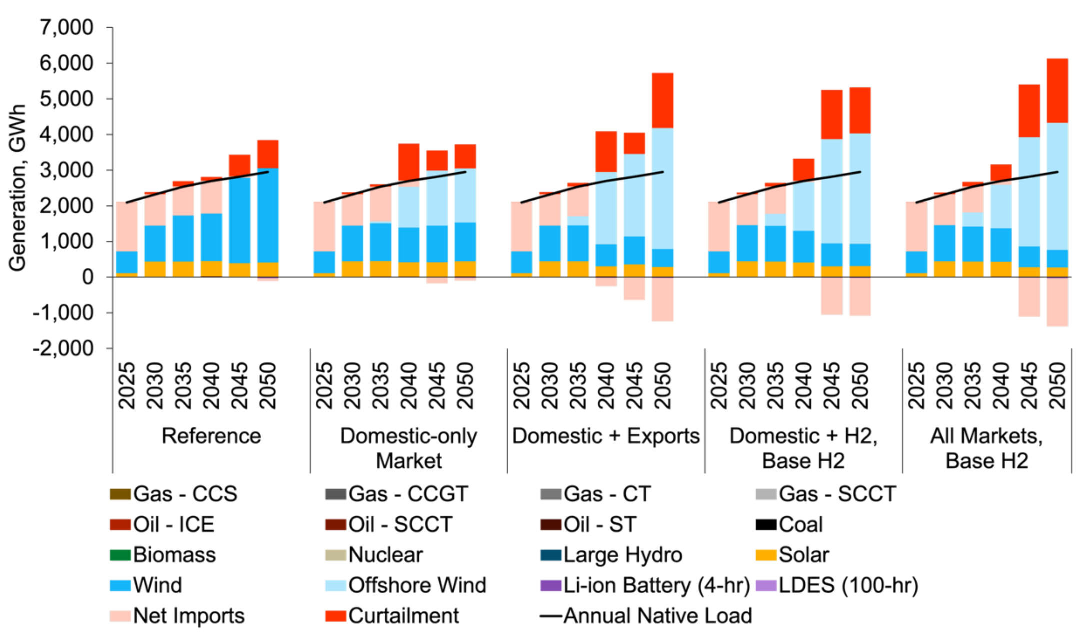
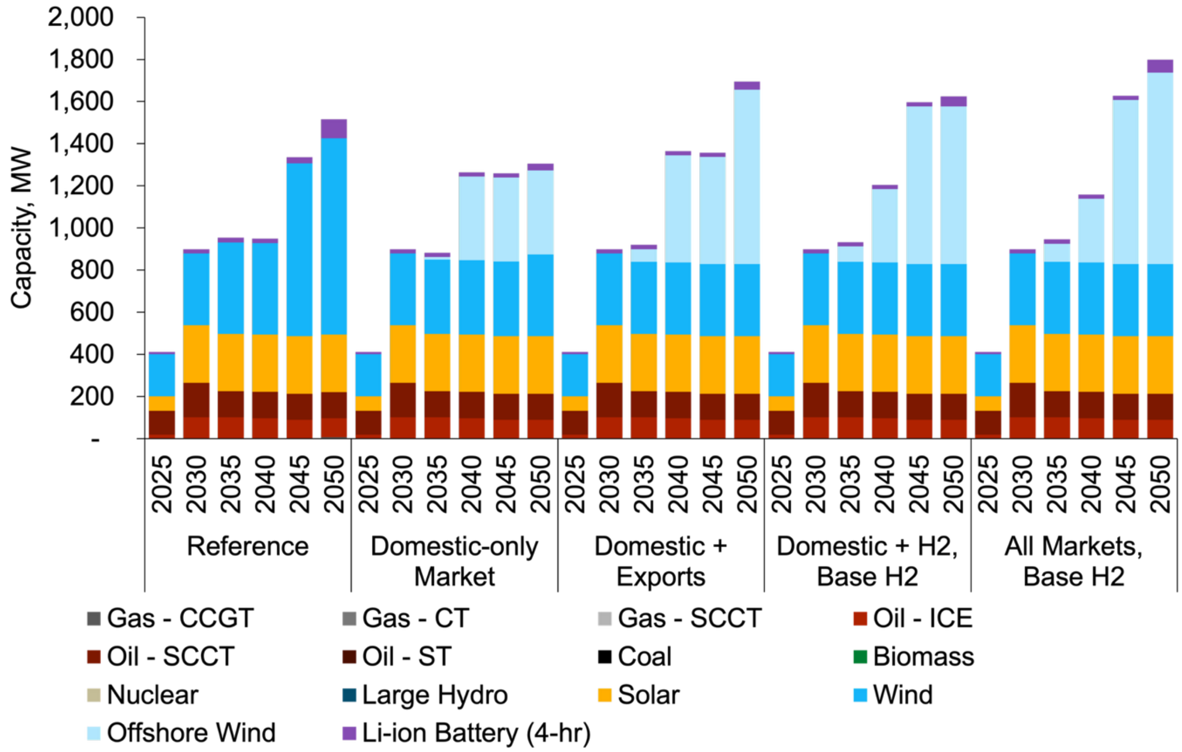


Figure 53. Prince Edward Island Installed Capacity (MW) Across All Scenarios



A.2. Resource Builds and Generation for Sensitivity Scenarios

High Hydrogen Scenario

Hydrogen is a developing zero-carbon alternative, with uncertainty about the magnitude of impact it will have in the Atlantic Provinces. To capture a broader range of possibilities, E3 modeled a sensitivity of the hydrogen scenarios with a higher hydrogen load and greater offshore wind penetration to support these loads. In Figure 54 and Figure 55, E3 reports the total installed capacity and annual generation, respectively, between the base and high hydrogen scenarios. In the high hydrogen sensitivities, there is a higher load and wind deployment, and also higher curtailment. Curtailment occurs in hours when either generation exceeds loads, or transmission capacity between generators and load areas is insufficient for economic power delivery.

Figure 54. Total Installed Capacity (MW), Base vs. High Hydrogen Scenarios

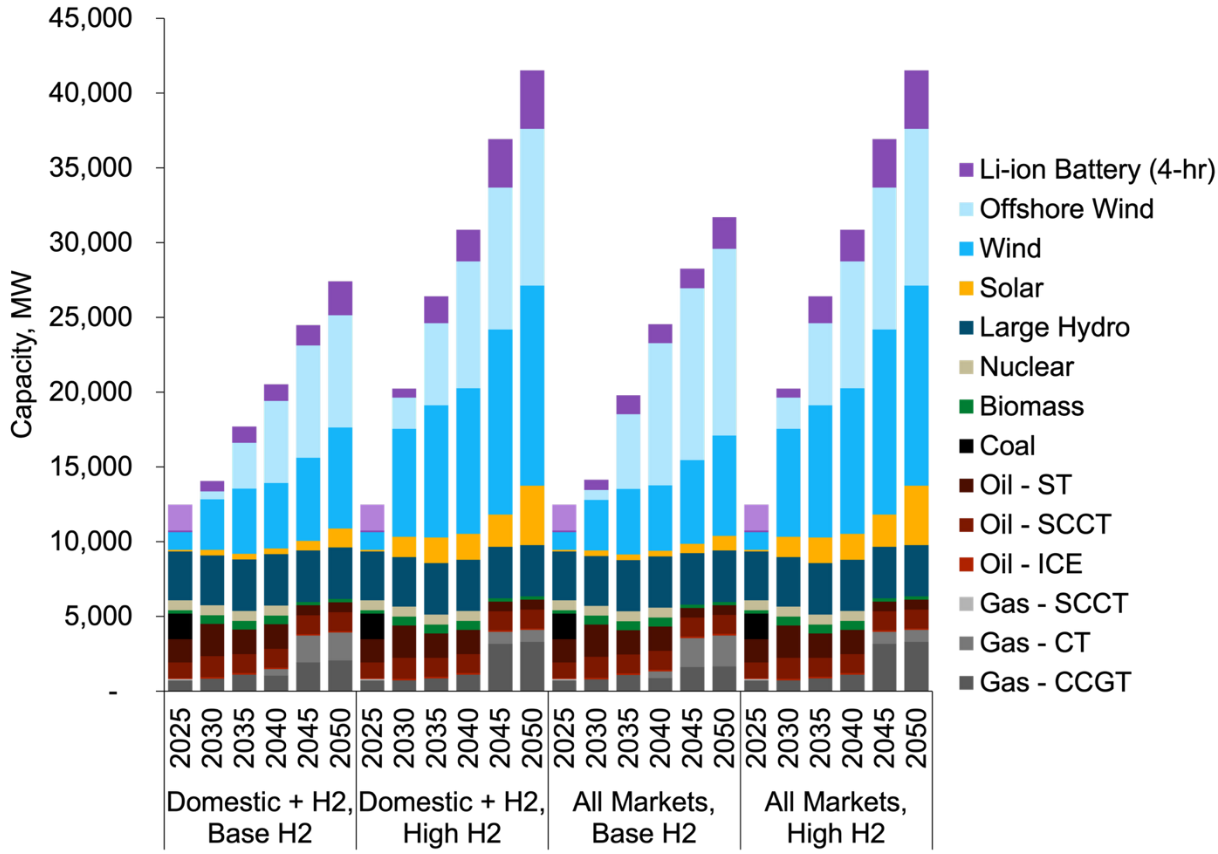
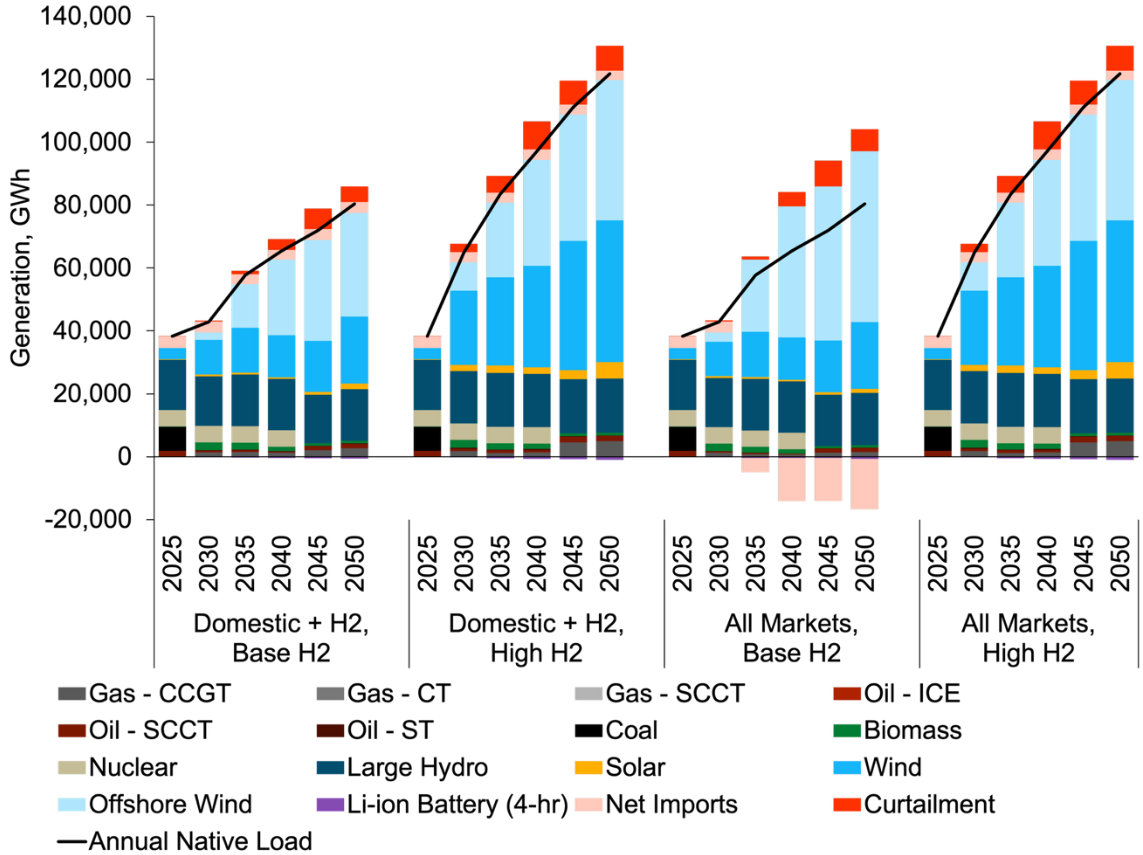
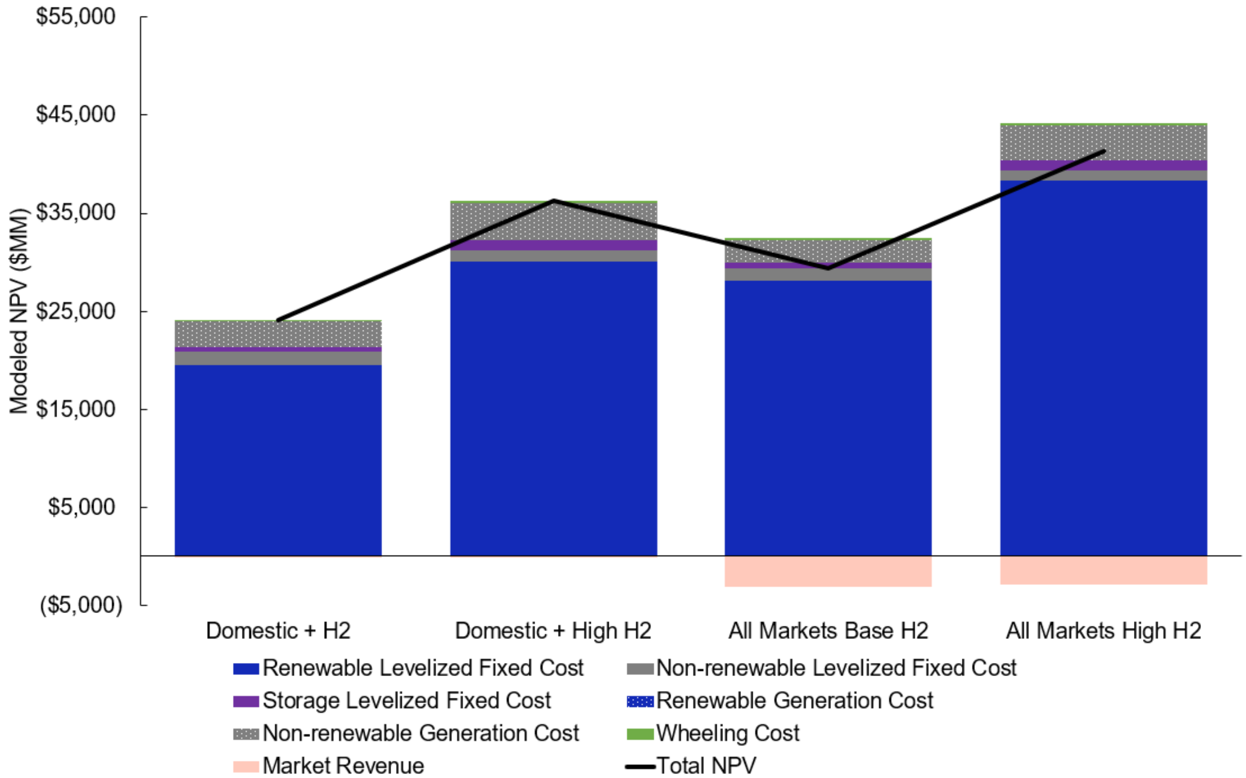


Figure 55. Annual Generation (GWh), Base vs. High Hydrogen Scenarios



When considering the impacts of an expanded hydrogen future in the Atlantic Provinces, it is also helpful to look at the anticipated effects on costs. In Figure 56, E3 shows the modeled NPV and annual cost of energy for all provinces for the base and high hydrogen sensitivities of the Domestic + H2 and All Markets scenarios. In both the Domestic + H2 and All Markets scenarios, the high hydrogen sensitivity has a higher NPV and a higher annual cost of energy ($/kWh) than the base hydrogen sensitivity, as expected. This increase in cost is due to the added capital expenses of incrementally more expensive wind, given current technology and market maturity.

Figure 56. Modeled Cost Comparison, NPV ($MM) Base vs. High Hydrogen Scenarios



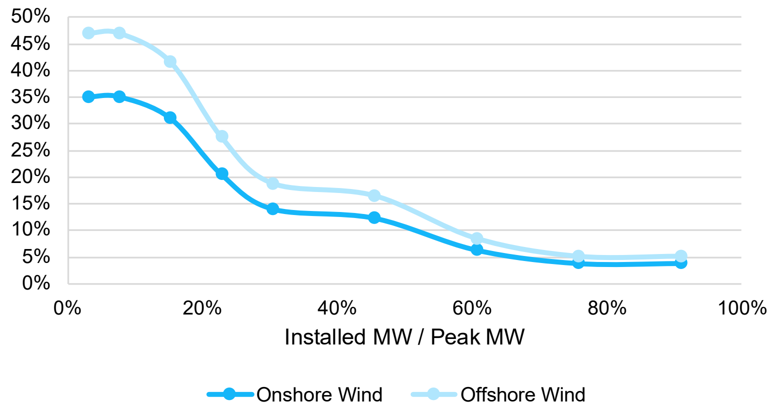
Appendix B. Additional Input Assumptions

B.1. Wind Effective Load Carrying Capability (ELCC) Curve Assumptions

Onshore and offshore wind resources are treated with a tailored ELCC methodology to better capture their partially correlated generation profiles and distinct reliability contributions. Because these resources exhibit both overlap and diversity in output, modeling them on a single shared ELCC curve would overstate the extent to which additional capacity of one resource diminishes the marginal reliability contribution of the other. Conversely, modeling them on fully independent ELCC curves would overstate their diversity and over-credit their combined capacity value.

To address this, both onshore and offshore wind are mapped to a common ELCC curve, but with an adjustment that applies a capacity penalty based on the observed correlation between their generation profiles. This penalty is a function of the installed capacity of the complementary wind resource and the degree of correlation in their hourly output, reducing the marginal ELCC contribution as overlapping capacity increases while preserving some diversity benefit. The penalty applied in this study is 0.05 for all provinces. This approach provides a balanced representation of reliability value, reflecting both shared weather patterns and resource diversity across wind types.

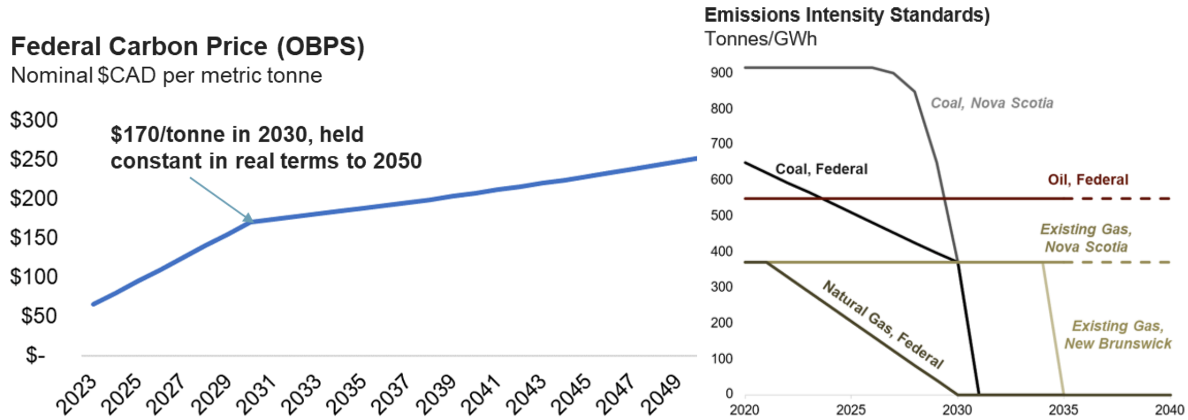
Figure 57. Onshore and Offshore Wind ELCC Curves, Incremental ELCC (%)



**Curves reflect generic onshore and offshore wind resources; individual resources are scaled based on their own CF compared to the resources used to develop these curves*

B.2. Carbon Pricing and Policy Assumptions

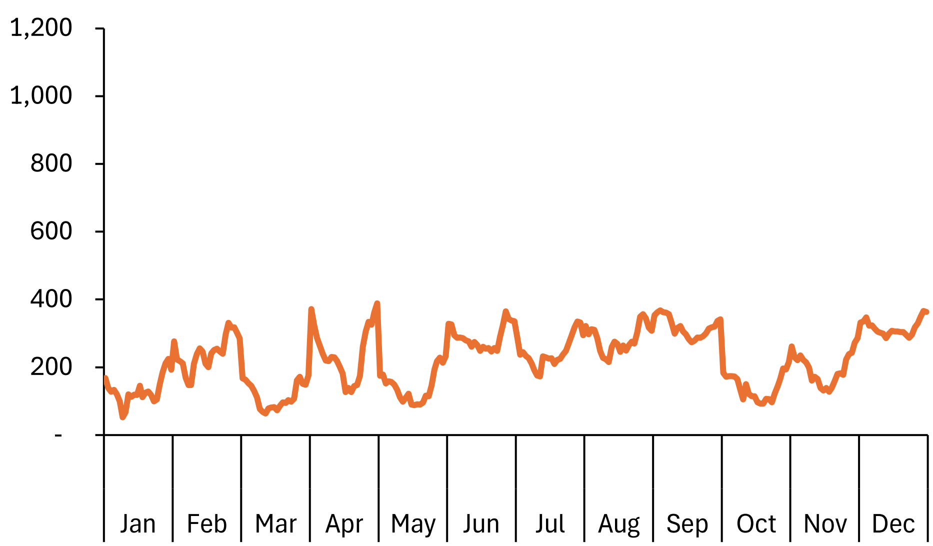
Figure 58. Federal Carbon Pricing Policy and Emissions Intensity Standards



B.3. Additional Import-Export Assumptions

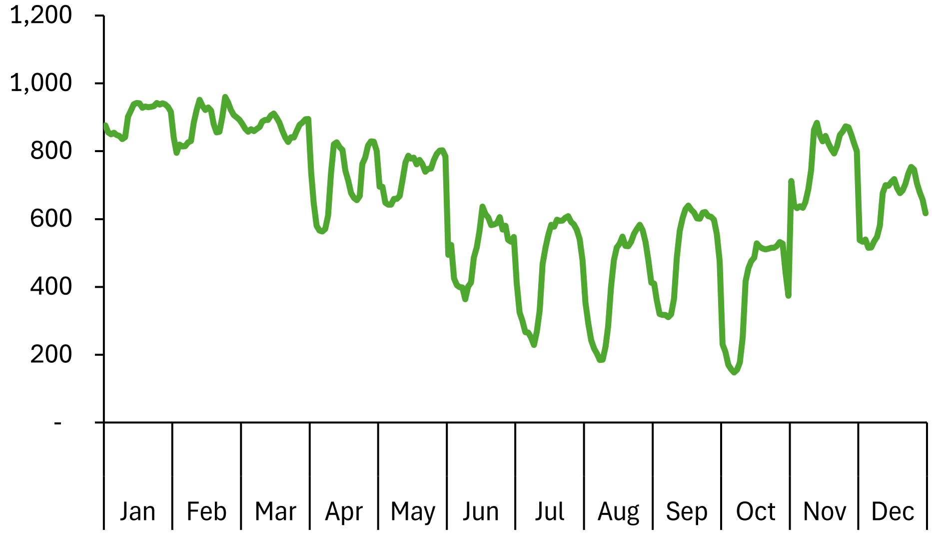
Figure 59 and 60 below illustrate the historical average flows across key interfaces.

Figure 59. 2023 Month-Hour Average Flows from New Brunswick to ISO New England (MW)[45]



[45] https://tso.nbpower.com/Public/en/system_information_archive.aspx

Figure 60. 2023 Month-Hour Average Flows from Hydro Québec to New Brunswick (MW)[46]



The NB-ISONE and NS-ISONE interfaces export to a market represented by a fixed hourly market price established using the E3 2023 ISO New England market price forecast. The HQ-NB interface interacts with the Hydro Québec market, which is represented using a flat, synthetic market price of $5.50/MWh (plus inflation). This price was selected to be slightly greater than the sum of the renewable integration charge ($2/MWh plus inflation) and the hurdle rate used for exports to Hydro Québec ($3.10/MWh plus inflation). The price is high enough to encourage exports of excess renewable energy when the only other option is curtailment but low enough to discourage exports to Hydro Québec over serving local loads.

Table 13. External Market Interface Assumptions Summary[47]

External Market	Connected Atlantic Province	Hourly Purchases	Hourly Sales	Market Price
ISO-New England	New Brunswick	None	Fixed to 2023 month-hour average flows	E3 Price Forecast

[46] https://tso.nbpower.com/Public/en/system_information_archive.aspx

[47] As noted elsewhere in this report, though Hydro Quebec and Labrador also have transmission linkages, those are not included in this study due to lack of publicly available data, and lack of interactive effects with the other Atlantic Provinces. Flows from Labrador to the Newfoundland Island System via the Labrador Island Link (and flow on to Nova Scotia via the Maritime Link) are modeled, effective capturing the impact that Labrador based generation has on portfolios, generation and dispatch elsewhere in the Atlantic Provinces.

Hydro Québec	New Brunswick	Up to 2023 month-hour average flows	Up to 1,000 MW	$5.50 plus inflation
ISO-New England	Nova Scotia	None	Up to installed offshore wind capacity built for export	E3 Price Forecast

B.4. Additional Hydrogen Assumptions

Hydrogen Demand Percentages Assumed in E3 PATHWAYS Model

Table 14. Percent of Energy Demand Assumed to be Met with Hydrogen

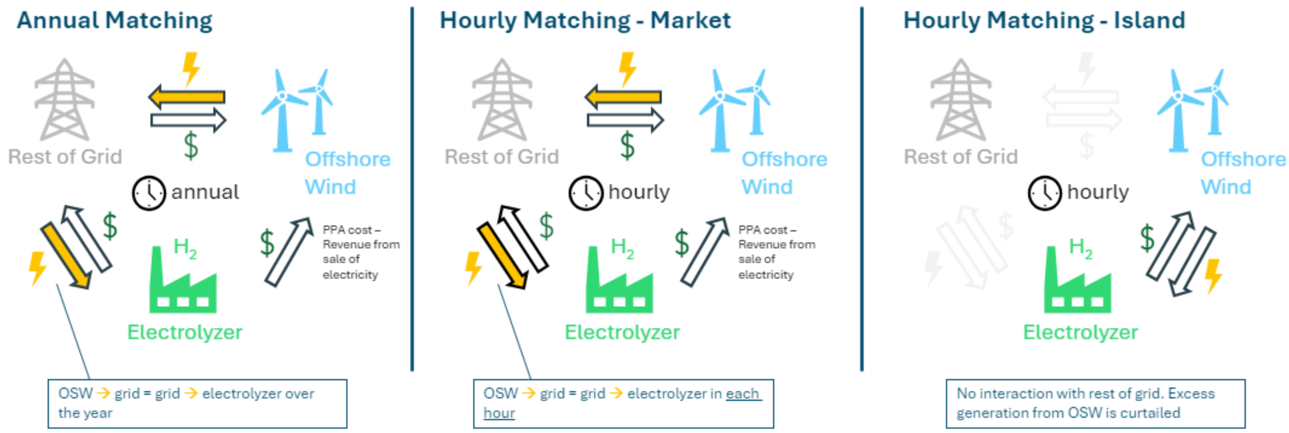
Sector	End Use	2030	2035	2040	2045	2050
Industry	Heating	0%	15%	30%	40%	50%
Transportation	Heavy Duty Vehicles	25%	38%	50%	65%	80%
Transportation	Aviation	0%	21%	42%	56%	70%
Residential	Heating	1%	1%	1%	1%	0%
Commercial	Heating	1%	1%	1%	0%	0%

Note: Aviation percentages are indicative of GJ SAF produced with H2, not GJ H2. The H2 to electrofuel conversion ratio is 1.224 GJ H2/GJ fuel.

B.5. Hydrogen Production Costs

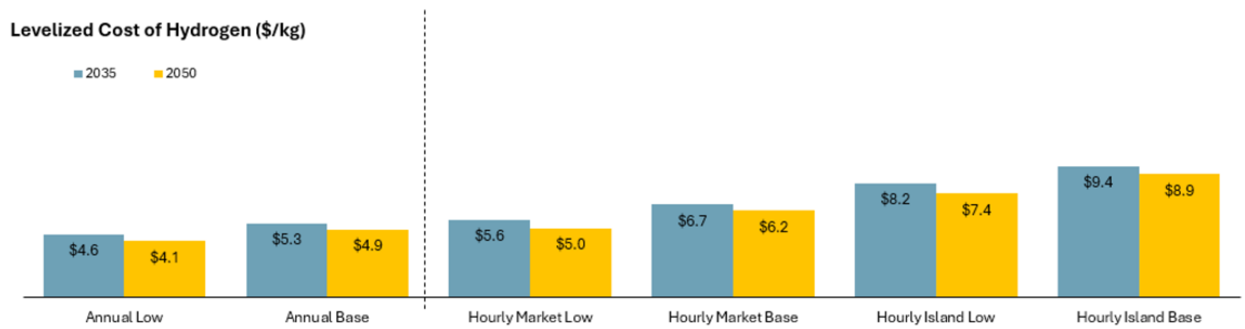
The cost of hydrogen was calculated for 3 operational scenarios—matching renewable production with electrolyzer charging on an annual basis (Annual Matching), matching renewable production with electrolyzer charging on an hourly basis, allowing interaction with the grid (Hourly Matching – Market), and matching renewable production with electrolyzer charging on an hourly basis in isolation from the grid (Hourly Matching – Island). E3 also ran two cost scenarios, a base scenario and a low-cost scenario that assumed lower offshore wind and alkaline electrolyzer capital costs. Both cost scenarios included the Canadian hydrogen investment tax credit. For operational parameters, E3 assumed that the electrolyzer operated at a 90% capacity factor and the offshore wind generated at a 60% capacity factor.

Figure 61. Operational Configurations in REMATCH



The results of this analysis showed that the least-cost sizing of offshore wind to electrolyzer capacity was a ratio of 1.5 to 1 for annual matching, and 3 to 1 for hourly matching. However, even in the low-cost annually matched scenario, the cost of hydrogen is $4/kg by 2050. In the hourly matched scenarios (compliant with European import regulations), this cost increases to as high as $7/kg in the scenario where the developer can sell excess power to the grid.

Figure 62. Levelized Cost of Hydrogen



Note: Outputs align with scenarios defined above (see previous figure).

It's important to note this analysis is sensitive to assumptions about the future that are highly uncertain. For example, these costs could be brought down substantially by additional federal hydrogen policy, like subsidies to developers on a production basis. Additionally, this analysis assumes offshore wind is the primary source of energy for hydrogen because the focus of the broader report is on offshore wind. Offshore wind capital costs also comprise the majority of the cost of hydrogen production calculated in this analysis. However, offshore wind is not the cheapest source of clean energy in the Atlantic Provinces, and most projects underway today are powered by *onshore* wind generation, which is substantially cheaper. Additionally, this analysis is solely focused on production and does not take into account the other infrastructure advantages the Atlantic

Provinces have, like their abundant geologic hydrogen storage potential, or shipping costs reduced by its proximity to Europe. However, to be competitive on a global scale, the Atlantic Provinces would need a substantial mobilization of capital and increased ambition in federal policy to enable the region to become a major exporter of hydrogen.

B.6. Known Existing Hydrogen Projects

Table 15. List of Existing Hydrogen Projects in Atlantic Provinces

Province	Project	Operational by	Details	Power Source
New Brunswick	Irving Oil	2023	5 MW electrolyzer capacity	N/A
New Brunswick	Port of Belledune & Cross River Infrastructure	2027	N/A	300-600 MW of new clean capacity
New Brunswick	[CLASSIFIED]	N/A	N/A	300 MW wind capacity
Newfoundland & Labrador	Copenhagen Infrastructure Partners/ABO Energy	2035	400,000 tons of hydrogen per year	5 GW onshore wind capacity, developed in three phases
Newfoundland & Labrador	Abraxas Power/Exploits Valley Renewable Energy Corp	N/A	200,000 tons of hydrogen and 1,000,000 tons of ammonia annually	3.5 GW onshore wind capacity and 150 MW solar capacity
Newfoundland & Labrador	EverWind - Burin Peninsula	2028 (partial)	5.5 GW electrolyzer capacity	10 GW of onshore wind and 2.5 GW of solar capacity (2 GW wind will be online by 2028)
Newfoundland & Labrador	North Atlantic Refining Ltd	N/A	90,000 metric tons of green hydrogen annually	N/A
Newfoundland & Labrador	Pattern Energy - Argentia Project	2028	160 MW electrolyzer capacity	300 MW onshore wind capacity
Newfoundland & Labrador	Project Nujio'qonik - World Energy GH2	2025	1.5 GW electrolyzer capacity	3 GW onshore wind capacity
Nova Scotia	Bear Head Energy	2027	2 GW electrolyzer capacity	3.5 GW clean capacity
Nova Scotia	EverWind Fuels - Point Tupper	2025	200,000 tons of hydrogen in 2025 and 1 million tons 2026 onwards	527 MW of onshore wind capacity by 2025, 650 MW by 2026
Nova Scotia	Simply Blue	N/A	N/A	600 MW powered by onshore wind and solar
Prince Edward Island	Aspin Kemp & Associates	N/A	2 MW of electrolyzer capacity	N/A