Newfoundland and Labrador Hydro
Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 | f. 709.737.1800
nlhydro.com

July 9, 2024

Newfoundland Power Inc.
Dominic J. Foley
55 Kenmount Road
PO Box 8910
St. John's, NL A1B 3P6

Consumer Advocate
Dennis M. Browne, KC
Browne Fitzgerald Morgan & Avis
Terrace on the Square, Level 2
PO Box 23135
St. John's, NL A1B 4J9

Island Industrial Customer Group
Paul L. Coxworthy
Stewart McKelvey
Suite 1100, Cabot Place
100 New Gower Street
PO Box 5038
St. John's, NL A1C 5V3

Labrador Interconnected Group
Senwung Luk
250 University Avenue, 8th Floor
Toronto, ON M5H 3E5

Re: *Reliability and Resource Adequacy Study Review* – 2024 Resource Adequacy Plan

Please find enclosed Hydro's 2024 Resource Plan, an update to the RRA Study, which is filed as a part of the *RRA Study Review*."[1]

The 2024 Resource Plan is comprised of a highlights document, an overview document, and four appendices as follows:

- Power the Province, a document that briefly highlights key considerations and outcomes of the 2024 Resource Plan;
- 2024 Resource Plan Overview;
- Appendix A: Memo from Hydro's third-party consultant, Daymark;
- Appendix B: Planning Criteria and Study Methodology;
- Appendix C: 2024 Expansion Plans: Development Process and Recommendation; and
- Appendix D: What Was Said Report: Summary of 2024 Public Engagement Results

For ease of reference, Hydro has also included a summary of abbreviations, definitions, and scenarios used in the 2024 Expansion Plans.

---

[1] Hydro's filings within the *RRA Study Review* are available on the of Board's website.
http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/index.php

Please note that the CT Options Report included as Attachment 4 to Appendix C contains substantial third-party, commercially sensitive information. The full report has been provided to the Board. Attached hereto is a version wherein the commercially sensitive information has been redacted.

The 2024 Resource Plan and other supporting documents will be available on Hydro's website and online at www.PowerTheProvince.ca.[2]

Hydro remains committed to working with the Board and stakeholders to help ensure an appropriate balance of cost and reliability for the future provincial electrical system.

Should you have any questions or comments about any of the enclosed, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh
Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
Maureen Greene, KC
Board General

Island Industrial Customer Group
Denis J. Fleming, Cox & Palmer
Dean A. Porter, Poole Althouse

Labrador Interconnected Group
Nicholas E. Kennedy, Olthuis Kleer Townshend LLP

Consumer Advocate
Stephen F. Fitzgerald, KC, Browne Fitzgerald Morgan & Avis
Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
Bernice Bailey, Browne Fitzgerald Morgan & Avis

Newfoundland Power Inc.
Lindsay S.A. Hollett
Regulatory Email

[2] The Power the Province website will go-live shortly after the filing of Hydro's 2024 Resource Plan.

2024 Resource Adequacy Plan

An Update to the Reliability and Resource Adequacy Study

July 9, 2024

A submission to the Board of Commissioners of Public Utilities

List of Contents

The components of the 2024 Resource Adequacy Plan include:

- Power the Province
- 2024 Resource Plan Overview
- Appendix A: "2024 Reliability & Resource Adequacy Process Review," Daymark Energy Advisors, May 9, 2024
- Appendix B: Planning Criteria and Study Methodology
    - Attachment 1: Forced Outage Rate Methodology
    - Attachment 2: "Energy Analysis Memo," Daymark Energy Advisors, May 9, 2024
- Appendix C: 2024 Expansion Plans: Development Process and Recommendation
    - Attachment 1: "Resource Cost Comparison," Daymark Energy Advisors, April 1, 2024
    - Attachment 2: "Uprate Report," Hatch Ltd., June 27, 2024
    - Attachment 3: "Accelerated Holyrood Combustion Turbine Installation Options Study—Final Report," Stantec Consulting Ltd., May 13, 2024
    - Attachment 4: "Long-Term Fuel Supply Study, Holyrood," Stantec Consulting Ltd., May 6, 2024
    - Attachment 5: "Impact of Prolonged Loss of LIL on Island Reservoir Levels," Hatch Ltd., July 2, 2024
- Appendix D: What Was Said Report: 2024 Public Engagement: *Reliability and Resource Adequacy Study Review*
- Abbreviations
- Definitions
- Scenario Summary Tables

POWER THE PROVINCE

2024 RESOURCE ADEQUACY PLAN

JULY 2024

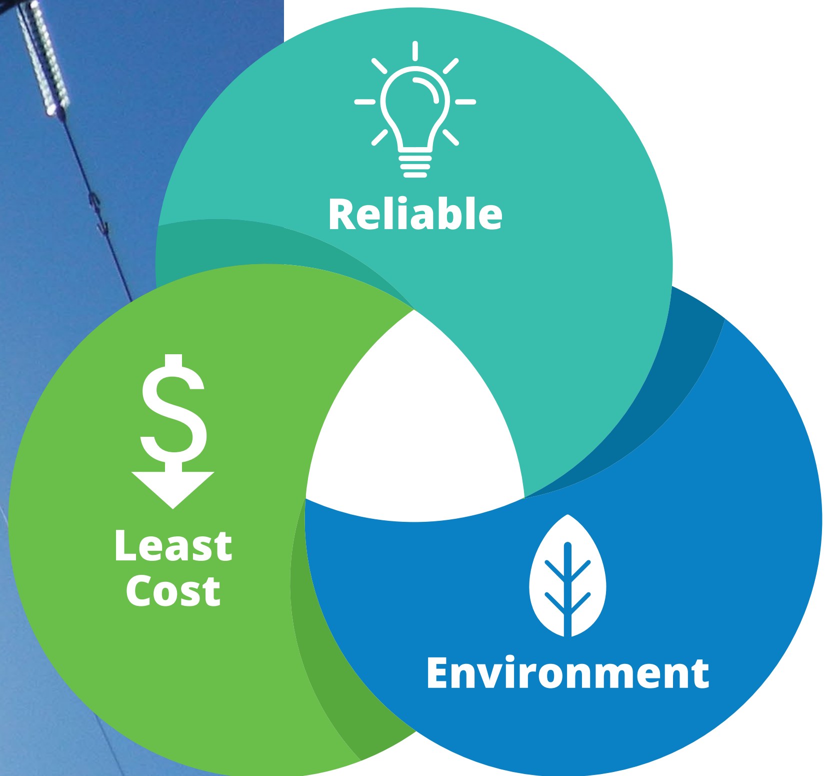
THE POWER OF PLANNING

We're planning for the future and working hard to power the province with safe, reliable electricity—it's something we all need—and we will need more.

It's a time of transition for our electricity system, and it's our responsibility to guide our province forward. To do so, we are balancing cost, reliability, and the environment in our decisions. This is our legislated obligation and our privilege.

In our thinking and planning in the last year, we also engaged you— our customers. We undertook a digital engagement process where we reached out to customers across the province to get their opinions on our next big decisions.

Customers have been very clear. The cost of living, including electricity rates, is a concern. And that is why the recommendations presented in our report are based on the minimum investment required—on what we absolutely and urgently must do to support reliability and begin to prepare for load growth. There will be more decisions to come.



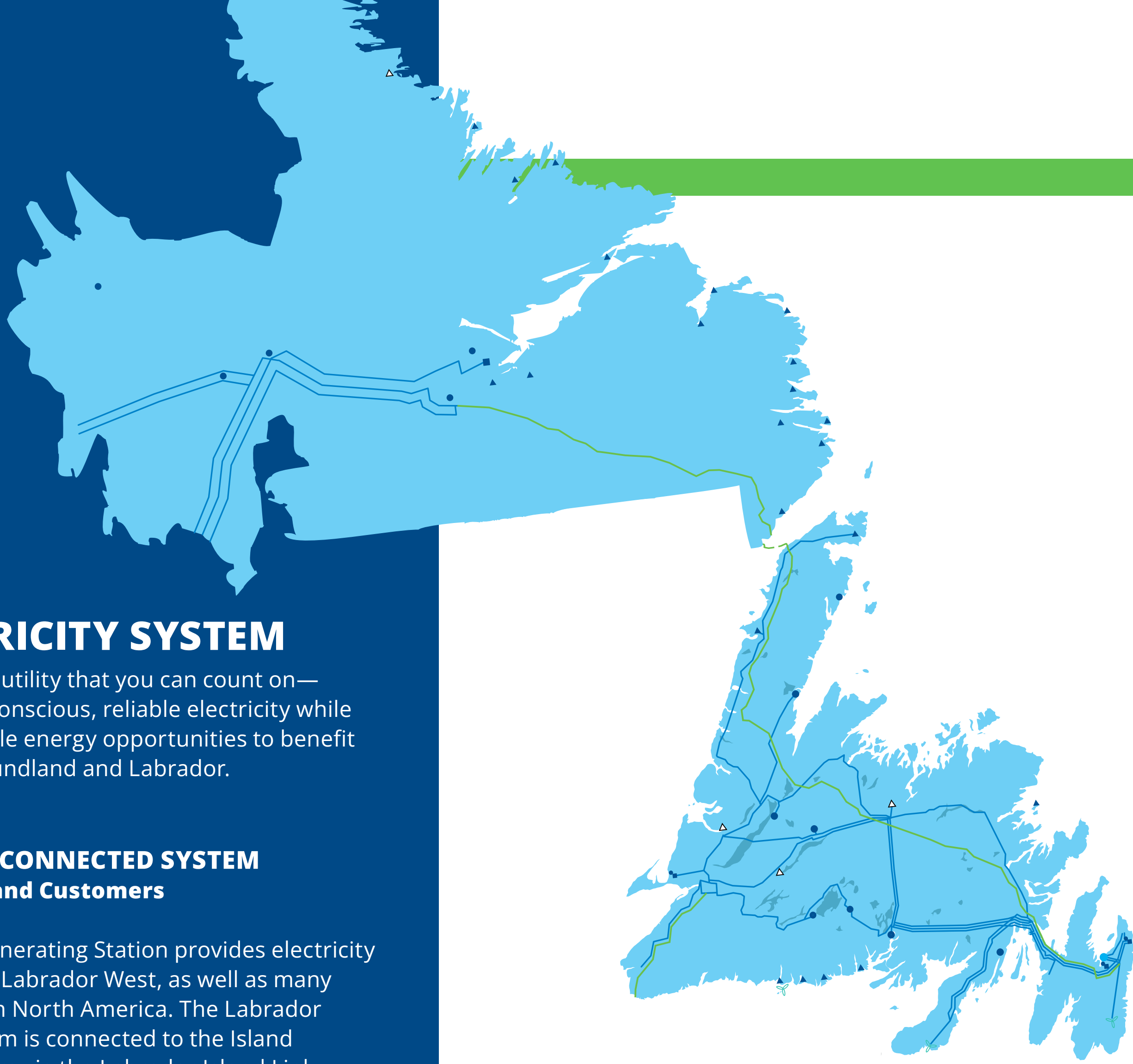
OUR PLANNING PROCESS

The 2024 Resource Adequacy Plan (2024 Resource Plan) is a continuation of our planning process and provides an in-depth analysis of how much electricity customers will need over the next ten years and the best resource options to satisfy those growing needs.

We have considered which assets should be maintained and if new assets are required to ensure we have the right energy mix to meet growing demand for electricity, while ensuring we deliver on the reliability our customers expect—and deserve. The 2024 Resource Plan focuses on meeting forecasted growth for the Island and maintaining reliability for Island customers.

This summary highlights what we've learned from our extensive research and the decisions we are making to ensure we continue to meet our customer's changing needs. The full plan with documentation is also available at PowerTheProvince.ca.

In 2018, Newfoundland and Labrador Hydro (Hydro) completed a Reliability and Resource Adequacy Study, filed with the Board of Commissioners of Public Utilities Board (PUB) the same year. The filing addressed our long-term approach to providing continued reliable service for our customers. Prior to this 2024 update, Hydro provided updates in 2019, 2021 and 2022, as well as numerous supporting filings.



OUR ELECTRICITY SYSTEM

Hydro is the people's utility that you can count on—providing safe, cost-conscious, reliable electricity while harnessing sustainable energy opportunities to benefit the people of Newfoundland and Labrador.

LABRADOR INTERCONNECTED SYSTEM
Serving 10.8 thousand Customers

The Churchill Falls Generating Station provides electricity to Labrador East and Labrador West, as well as many homes across eastern North America. The Labrador Interconnected System is connected to the Island Interconnected System via the Labrador Island Link. The system is also connected to the North American Grid via 735 kilovolt (kV) transmission lines from Churchill Falls to Québec.

ISLAND INTERCONNECTED SYSTEM
Serving 296.8 thousand Customers
(including the 274 thousand serviced by Newfoundland Power)

Most of the electricity on the Island is generated from hydroelectric plants at either Muskrat Falls or one of our facilities off the Avalon Peninsula. Electricity is delivered over either the Labrador Island Link or the bulk 230 kV transmission system extending from Stephenville to St. John's.

RURAL AND ISOLATED SYSTEMS
Serving 4.4 thousand Customers

Our teams operate 23 remote diesel plants throughout the province. For many rural communities, this is the sole source of electricity. While currently this is the most affordable and reliable supply for these remote areas, we are always looking for new clean solutions to power these communities.

HYDRO'S 2023 HIGHLIGHTS

We provided nearly eight terawatt hours of energy to more than 300,000 customers across the Island.

Hydro's Island customers experienced the best system reliability in over a decade with the lowest number of service interruptions since 2012.

92% of electricity generated by Hydro for use in this province was from net-zero energy sources—99% if including export energy.

We delivered over four terawatt hours of this excess energy to external markets—just under half of what the island uses in an average year.

Maintained nearly 8,000 megawatt (MW) of generation assets and more than 10,000 kilometers (km) of transmission and distribution lines.

The Labrador Island Link had an equivalent forced outage rate of 4%, essentially available 96% of the time (not accounting for planned maintenance outages). The Muskrat Falls Plant also performed better than the Canadian average for reliability.

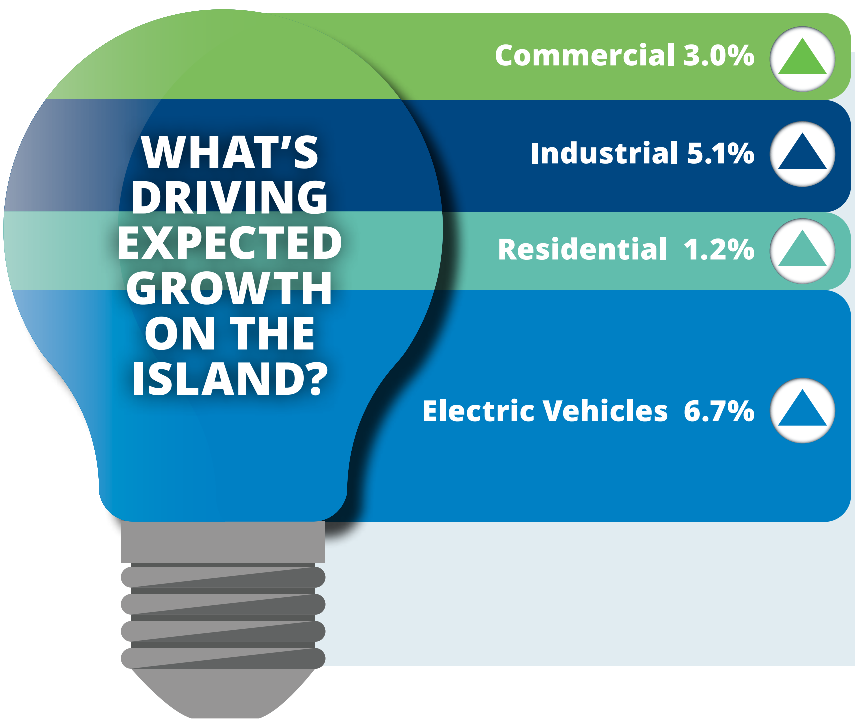
"Forced outage rate" is the industry's standard metric to qualify an assets reliability—how often an asset was unexpectedly offline.

WE NEED POWER

The Muskrat Falls Project is now online, and while we recognize there were many challenges, we are seeing value from the project. At the time of the decision to build Muskrat Falls, it was a solution to meet the forecasted demand for the coming period. That decision was more than a decade ago.

Today, electrification of our society has changed everything and new electricity supply solutions are needed as soon as possible. We are again looking to the near future to determine what will be needed for the next ten years and beyond.

We need more electricity. There is no question. We must expand the electricity system to be ready for what's coming and we are fortunate to have many options. Hydro too, is preparing for the transition to cleaner sources and the retirement of Holyrood Thermal Generating Station after 2030.



Public policy is rapidly shifting the energy sector at a velocity that hasn't been seen since the 50s and the 60s. This accelerating shift has driven industrial and commercial growth, electrification of vehicles, and a switch from oil to electric home heating.

The total energy use on the island was almost 8 terrawatt (TWh) in 2023. By 2034, it's expected to grow to 9.2 TWh. That's a 16% increase for the island alone. This growth forecast is conservative. It doesn't include significant industrial growth such as from hydrogen facilities or other major mining opportunities. As these opportunities progress, Hydro may need even more supply.

WHAT'S HAPPENING IN LABRADOR?

Significant work is ongoing to address the incredible energy opportunities throughout Labrador. Hydro is working closely with Indigenous peoples, customers and partners to advance these needs in our largest geographical service region.

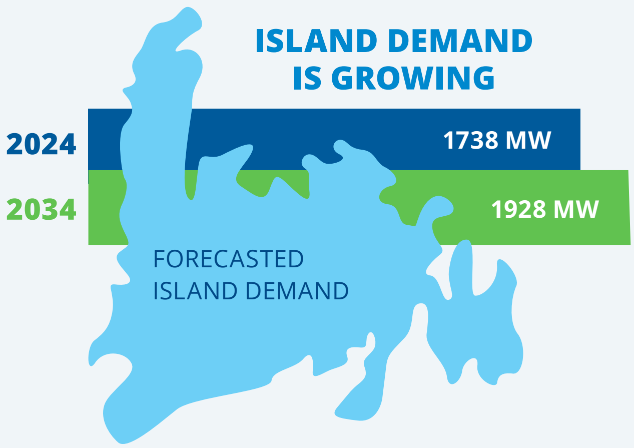
Load growth in Labrador is primarily driven by requests from new and existing industrial customers. The need for new transmission is addressed through the Labrador Network Additions Policy, which protects current ratepayers on the Labrador Interconnected System by limiting rate increases associated with the costs of any new asset required to serve these new load requests. The policy helps achieve a reasonable balance in the sharing of the benefits and the costs of these system investments between new and existing customers.

We have considered several scenarios in Labrador. Predicted growth ranges from 300 MW to nearly 700 MW in the next ten years. This could mean that by 2034 peak demand (1,184 MW) would nearly triple that of 2023 (422 MW). We are working with new and existing industrial customers to plan accordingly and understand the system impacts.

A CUSTOMER FOCUSED APPROACH

Hydro hears customers and is working hard to not overbuild. If you overbuild, it costs more than necessary.

To ensure we are not overbuilding for scenarios that do not materialize, we looked at the minimum investment required, which reflects the slowest decarbonization trend and, therefore, the least investment and least impact on cost. Additional investment may be required, but we are carefully analyzing our needs to ensure we make the right investments at the right time.



How did you determine what is needed?

Changing consumer behavior, industry changes and opportunities, as well as the evolving climate change policies have all accelerated demand for electricity compared to what has been seen in recent years and decades. We must also consider reliability of the system for all our customers.

As a result, we can no longer plan for a relatively stable and predictable electricity future. As all utilities, we must now manage the impacts of this acceleration and the uncertainty it brings for our system operators.

To manage this uncertainty, we developed and forecasted for a variety of scenarios, ranging from slow to fast growth and speed of decarbonization.

To do this, utilities apply statistical modelling to determine how much electricity is needed and which resources are available to best meet the expected demand across the scenarios.

Our analysis takes into account many factors influencing reliability, cost, and environmental impact of options. The models consider historical forecasts, fuel price and availability, weather and climate, current asset status and performance, resource options, and timelines to approve, build, and connect new resources.

Hydro's analyses are reviewed by an external consultant.

HOW MUCH DOES THE ISLAND NEED?

We need both capacity and energy.

Capacity is the maximum amount of electricity system can produce at any given time, measured in megawatts.

Energy is the amount of electricity produced over a specific period of time, measured in watt-hours.

Based on the minimum investment required, we need at least 385 MW of additional capacity and 1.4 TWh of new energy by 2034 to address load growth and reliability needs.

THE LABRADOR ISLAND LINK

The Link is online and delivering great value.

"Forced Outage Rate" is the industry's standard metric to qualify an assets reliability—how often an asset was unexpectedly offline. The Labrador Island Link had an equivalent forced outage rate of 4% in 2023, essentially available 96% of the time (not accounting for planned maintenance outages). As expected with any new asset, there are items to address early in its operation.

Our analysis has factored in a range of potential performance scenarios for the Labrador Island Link for the longer term. Our plan also reflects careful consideration of appropriate backup generation in the event of an outage on the Labrador Island Link.

Together with external experts, we have been studying the Labrador Island Link's reliability and are working to better understand the impact of climate change, with a focus on various icing events and conditions. As more events are possible in a climate changing world, we have been taking action to implement recommendations such as improved monitoring, including the installation of additional weather stations, as well as structural reinforcements in specific areas.

A NEW APPROACH TO MAJOR PROJECTS

One of the key lessons learned from the Muskrat Falls Inquiry was to ensure that more of the upfront planning and supporting evidence was gathered and made available for external examination prior to moving forward with construction. That is exactly what Hydro is now doing—we have explored many potential solutions for what is viable and we will continue to fully vet these options before submitting applications for the right solutions to our regulator.

Informed by the Inquiry, and to prepare to bring these new sources of supply online, we have formed a Major Projects Team comprised of experienced subject matter experts from across our organization, and across a variety of professional trades and corporate services. This team will be supplemented by experts as necessary, with oversight of Hydro's Executive and Board of Directors.

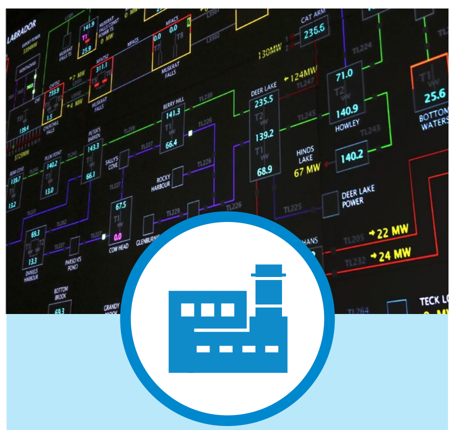
SOLUTIONS

Even in the minimum investment case, we need to consider both transmission and generations assets to meet the expected demand, while safeguarding the reliability of the electricity grid. Our plan includes only what we absolutely MUST do to prepare for load growth AND maintain the reliable service our customers expect—and deserve.

Below are the solutions we will continue moving forward to increase both capacity and energy on the Island Interconnected System. With the analysis and data we have to date, these are our first decisions on the next supply sources. The ongoing work we are completing, such as obtaining Class 3 cost estimates, will inform final decisions before submission to the PUB for approval.

MORE HYDRO CAPACITY
Bay d'Espoir Unit 8
~150 MW

One option for increasing capacity is an additional unit at our Bay d'Espoir Hydroelectric Generating Station. Hydro has been advancing the Front-End Planning and Engineering to ensure we have all the evidence needed to support our application to build. Adding to the efficiency of the project is that it would be within the footprint of the existing facility. This new unit also supports reliability of service for customers.



MAINTAINING RELIABILITY
Combustion Turbines
~150 MW

Another option, critical for ensuring reliable backup generation and meeting demand during peak times are combustion turbines on the Avalon. This solution has the ability to use renewable fuels, once they are reliably available in our region. We have been advancing the Front-End Planning and Engineering, as well as the Environmental Assessment process to ensure we have all the evidence needed to support our application to build.

MORE ENERGY
More Wind Integration
~1.4 TWh

Electrification and transition to non-emitting sources is also driving the need for more energy, which two years ago wasn't predicted by the modelling. We will continue to engage with existing and new wind proponents to explore wind integration and expect to issue an Expression of Interest for Energy next year.

WHAT'S NEXT?

Every utility across Canada is planning for what's needed. Hydro too, has put great thought and analysis into how we will continue to reliably serve customers for the next decade, and beyond.

We have a plan to power this province.

Our plan reflects a moment in time, considering all the information available to us today. We will continue to revisit as new information and technologies become available in the coming months and years. This will appropriately inform our next decisions.

Our vision for a clean energy future can only be achieved by working together. As we look for new ways to meet the future needs of our system, we are excited to work with our customers, Indigenous peoples, communities, industry, the PUB, Intervenors, and Government to positively contribute to the sustainable, economically bright future of Newfoundland and Labrador.

2024 Resource Plan Overview

newfoundland labrador hydro

Executive Summary

As the primary generator and transmitter of power throughout Newfoundland and Labrador, Hydro plays a critical role in the province—reliably powering homes, businesses, and key industries.

Hydro prioritizes its responsibility for the delivery of cost conscious electricity to customers while ensuring the maintenance and expansion of an efficient electricity system—both for today's needs and the rapidly growing electrical requirements associated with the transition to a green economy.

As electricity becomes increasingly integral to daily life—including through the continued electrification of fossil fuel-based transportation, space heating, and industrial processes to assist in decarbonization—it is essential for Hydro to make informed, justified, and timely decisions.

Initial Focus on the Island

For this filing, the Island and Labrador Interconnected Systems have been assessed separately, focusing on the production of an Island Interconnected System Expansion Plan that satisfies both capacity and energy requirements. Due to the separation of planning criteria for the Labrador Interconnected and Island Interconnected Systems, Hydro's 2024 Resource Plan[1] focuses on the expansion of the Island Interconnected System.

Development in Labrador is important to Hydro and the province. There continues to be merit in planning for the Labrador Interconnected System separately to ensure reliability in Labrador is maintained, which will require the development of Labrador-specific planning criteria in the future.

Listening to Electricity Customers

Hydro seeks the perspectives of everyone who has an interest in or is affected by decisions impacting the delivery of safe, reliable electricity in an environmentally responsible manner. It is embedded in Hydro’s core values and is one of the goals in Hydro’s Strategic Plan.[2]

[1] Hydro’s 2024 Resource Plan is filed as part of the ongoing *RRA Study Review*. Hydro’s filings within the *RRA Study Review* are available on the Board’s website.
http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/index.php
[2] “We Are Hydro: Strategic Plan 2023–2025,” Newfoundland and Labrador Hydro, December 12, 2023.
https://nlhydro.com/wp-content/uploads/2023/12/NEW-strategic-plan-FINAL-DEC-12-WEB.pdf

Hydro completed a digital public engagement survey in January 2024 with questions relating to reliability, cost, investment, growth, clean energy, and options for new sources of electricity. Administered by a third-party research partner, Hydro applied research methods consistent with engagement activities used by other utilities across Canada. Hydro's approach follows IAP2 principles. More than 2,000 responses were received and feedback highlights are provided in Figure 1.

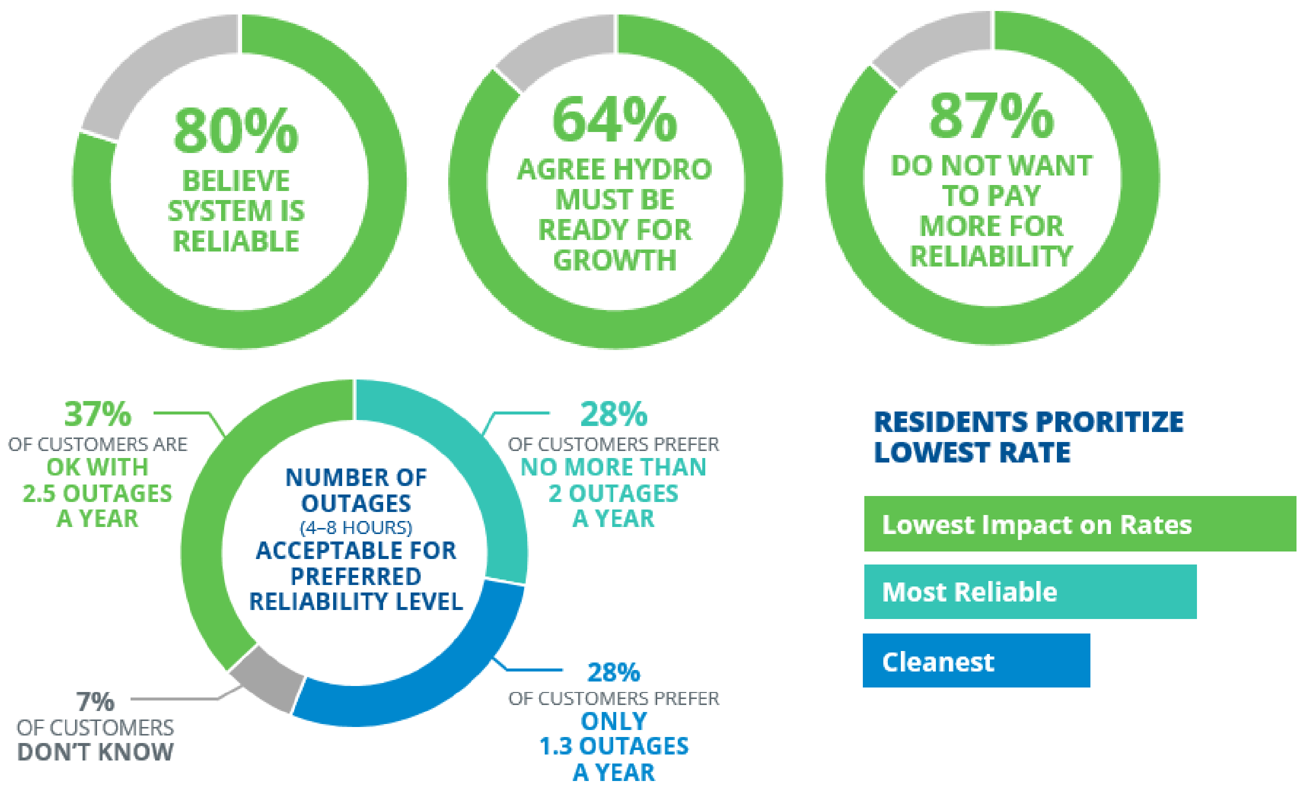


Figure 1: Public Engagement Feedback

The engagement confirmed that the Muskrat Falls Project remains top of mind for customers. In filing the 2024 Resource Plan, Hydro is working to ensure appropriate scrutiny of its decisions while striving to honour the lessons learned from the past to make recommendations that are in the long-term best interest of all electricity customers in Newfoundland and Labrador. The 2024 Resource Plan and any resulting future applications for new generation will be under consideration by the Board in a transparent process.

Growth in System Demand

Net-zero GHG emission targets for the electricity sector and for the economy and other policy changes to mitigate the impacts of climate change are having a transformational impact on the global electricity industry, increasing the demand for clean electricity at a speed not seen in decades. As a result, policy leaders and global think tanks indicate urgent and prudent action is required to meet this growing global demand.

Newfoundland and Labrador is facing the same increase in demand and associated challenges, while also starting from a highly renewable grid. As the province's Crown utility and main generator of electricity, Hydro is legislatively required to provide safe, reliable, least-cost, and environmentally responsible electricity to customers.[3]

> ***"This transition is, at its core, about producing more clean energy, using it more productively, and keeping it affordable."[4]***
>
> **CANADA ELECTRICITY ADVISORY COUNCIL**

Load Forecasting

In developing the 2024 Resource Plan, Hydro considered the recent major shifts in public policy and customer preferences. This has increased the demand for clean electricity to meet renewable energy targets, including net zero by 2050. As a result, Hydro incorporated these major shifts into its load forecast and completed an in-depth analysis of numerous supply options to meet growing demand and the criteria for reliable electricity service. Hydro has analyzed how much power the province will need and, in line with its mandate, assessed the generation options to best meet this need.

> ***The increasing demand for electricity in Newfoundland and Labrador is primarily driven by provincial economic forecasts, including population increases, industrial growth, and the need for reliable power to support electrification.***

[3] *Electrical Power Control Act*, 1994, SNL 1994, c E-5.1, s 3(b)(iii).
[4] "Powering Canada: A blueprint for success," Canada Electricity Advisory Council, May 2024. https://natural-resources.canada.ca/our-natural-resources/energy-sources-distribution/electricity-infrastructure/the-canada-electricity-advisory-council/powering-canada-blueprint-for-success/25863

Annually, Hydro develops an expected load forecast (also known as the Reference Case) of firm electric power demand and energy requirements, to assess the impacts of customer, demographic, and economic factors on the future provincial electricity load requirements. The resulting load forecast is a critical primary input to Hydro's overall planning, budgeting, and operating activities. As part of the *RRA Study Review*, Hydro filed its 2023 Long Term Load Forecast in March 2024. The forecast was produced in the third quarter of 2023; it covers the period through 2034 and is the basis for Hydro's 2024 Resource Plan, which covers the same period. For this planning exercise, a range of load forecasts was developed separately for the Island and Labrador Interconnected Systems. For the 2024 Resource Plan, three forecasts were developed to reflect the range of forecasted Island Interconnected System load requirements—the Reference Case (the expected load), Slow Decarbonization (which assumes a lower load than expected), and Accelerated Decarbonization (which assumes a higher than expected load).

Hydro's Expansion Model has identified the least-cost options to reliably meet the requirements of the system under each scenario. Hydro's analysis of the Reference Case determined that 500 MW of new generation, to address an additional 16% of current Island demand, would be required by 2034 to allow for the retirement of Holyrood TGS, as shown in Figure 2.

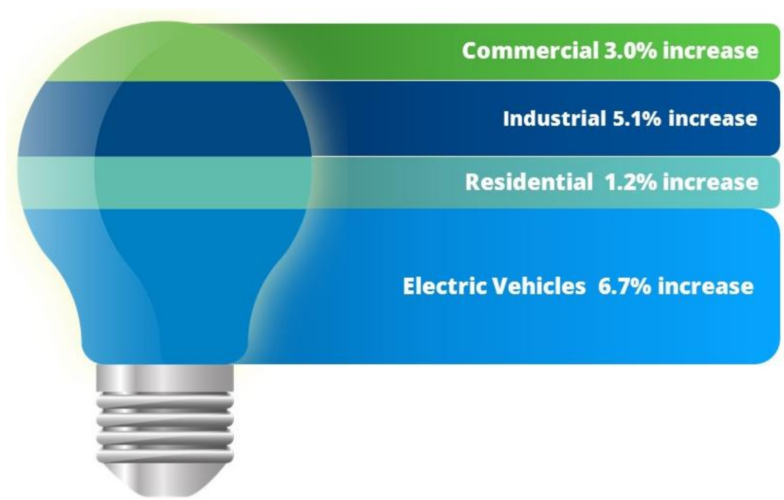


Figure 2: Drivers of Island Demand

Reliability

Reliability standards are metrics that aim to quantify system reliability in terms of expected hours of customer outages per year. This allows Hydro to understand not only the investment required to maintain the current level of reliability but the investment required to achieve greater reliability, consistent with industry benchmarks. Hydro's reliability planning criteria consists of long-standing criteria that have been used to meet system reliability for decades. In addition, more recent planning criteria have been included to reflect the interconnection to the North American Grid via the Maritime Link and the completion of the LIL, which delivers power from Muskrat Falls in Labrador to Soldiers Pond on the Avalon.[5] The Island Interconnected System should have sufficient generating capacity to limit the loss of load to a manageable level in the case of a LIL shortfall event. Asset retirements also impact the reliability requirement, including the planned retirement of the Holyrood TGS and the Hardwoods and Stephenville GTs during the study period.

Prudent Minimum Investment Required Approach

The provincial electricity system will require new on-Island generation to meet load growth and provide reliable backup generation to enable the planned retirement of aging fossil fuel-based assets. For the 2024 Resource Plan, Hydro has analyzed eight scenarios based on the three forecasts, each reflecting a unique set of criteria and assumptions around reliability and load growth. Examining scenarios with varying assumptions allows for a view to what supply could be needed and ensures broad thinking has occurred. In all eight scenarios, additional investment for generation resources is required to ensure adequate supply.

Hydro has worked with independent experts throughout this analysis whose role was to challenge Hydro to investigate alternative assumptions, solutions, and scenarios to test the results. The 2024 Resource Plan is the result of this analysis, outlining an urgent need for new electricity generation to be in service within the next decade.

While predicting the exact future needs of the electrical system is challenging, considering a range of realistic outcomes allows Hydro to make prudent decisions and contingency plans that address the current and future requirements of the Island Interconnected System. This is normal utility planning. Planning for the highest load growth scenarios without sufficient certainty may lead to overbuilding, unnecessarily increasing customer rates—a path not typically taken by utilities. Conversely, inaction and

[5] Under normal system conditions, the amount of energy that can flow over the LIL to the Island is limited by the interdependencies with the Maritime Link and Island load. For further information, please refer to Appendix B.

not advancing solutions when facing forecasted growth present significant risks to system reliability. To mitigate this risk, Hydro is progressing with a plan involving the Minimum Investment Required at this time while continuing to progress planning for the Reference Case.

Hydro's plan to progress the Minimum Investment Required includes:

- Construction of a new 154 MW hydroelectric unit (Unit 8) in Bay d'Espoir;
- Construction of a new 150 MW CT resource with renewable fuel capabilities on the Avalon;[6] and
- Integration of 400 MW installed capacity of wind generation.

Hydro recognizes that while the Minimum Investment Required a considers cost, reliability, and environmental impacts, it does not meet the reliability requirements should the 16% of Island load growth in the Reference Case occur. However, the Minimum Investment Required Expansion Plan remains a significant investment in and of itself and the timing to have these new assets in place is critical to maintain the reliability of the Island Interconnected System.

This conservative approach by Hydro represents the Minimum Investment Required—what absolutely must be done to prepare for load growth while supporting the system. The Minimum Investment Required represents supply additions that are common under <u>all</u> scenarios, including the first steps in the Reference Case.

Resource Planning is an iterative process. Hydro is planning to complete the next update to its Resource Adequacy Plan in 2026. In the interim, Hydro will continue to analyze the least-cost option to satisfy the Reference Case and continue monitoring load changes and resource capabilities. As the precise trajectory of load growth over the next decade is uncertain and LIL performance is still being proven, Hydro will continue preplanning additional expansion alternatives, should they be required.

Actions Taken to Advance Hydro's Plan

To mitigate the risks associated with resource planning decisions, Hydro has conducted an extensive analysis of various potential outcomes, collaborated with relevant parties on phased decision-making,

[6] While Hydro has assumed 150 MW of CT capacity based on the ability to fuel a CT of this size, the nominal plant rating may marginally differ depending on CT procurement.

and initiated supply additions common to all scenarios. Hence, the projects identified are the preferred initial solutions to meet the system's capacity needs across all forecast scenarios.

Hydro is advancing the planning, engineering, and EA of two critical additions to its resource supply—a new unit in Bay d'Espoir and a new CT on the Avalon. Hydro is also planning for the integration of wind power to meet future energy needs.

Early estimates indicate these new assets will require an investment of $1.2 to $1.6 billion along with the procurement of onshore wind supply, which will come in the form of a PPA with private wind energy generating companies. The integration of wind, Bay d'Espoir Unit 8, and a new CT will add capacity and energy to enable Hydro to serve the increasing load on the system; this will result in the generation of additional revenue for Hydro while enabling the retirement of aging thermal generating assets and offsetting their associated costs.

A Collective Responsibility for Urgent Action—Now and in the Future

Hydro believes it is necessary to establish a new efficient approach, in collaboration with the Board and parties, to advance appropriately justified major capital projects to balance the necessary regulatory process with the urgency required, ensuring the assets are in service in time to meet customer needs. EC, along with Hydro and other utilities across Canada believe the regulatory process and relevant parties should be an enabler of development to meet Canada's ambitions. As such, a collaborative approach that is reflective of this energy transition must be taken to ensure adequate supply is available when required.

"Provincial governments also need to establish a non-adversarial regulatory system to enhance trust and collaboration among the key players with the aim of achieving government policy priorities, societal expectations, and best value for customers."[7]

ELECTRICITY CANADA

While the shift to clean energy is underway, there are challenges. Provincially, the relevant parties have a collective responsibility for and oversight of decision-making. Timelines are key to ensuring Hydro has

[7] "Getting to Yes: The State of the Canadian Electricity Industry 2024," Electricity Canada, March 22, 2024, p. 15. https://issuu.com/canadianelectricityassociation/docs/soti_2024_e

the energy needed to reliably meet expected load growth, decarbonize the economy, and meet renewable energy targets, including net zero by 2050. New business proponents looking to decarbonize have the ability to grow the provincial economy significantly; however, electricity must be available.

Given the rapid pace of electrification and the potential risk and cost of delays, timely action is critical to ensure that new supply additions become operational before the energy demand exceeds supply.

The 2024 Resource Plan provides the opportunity for discussion with the relevant parties on key decision inputs to be used in the future planning of the Newfoundland and Labrador Interconnected System. The upcoming applications for supply solutions will confirm Hydro's analysis that the options identified are the best alternatives to meet its mandate of providing reliable electricity in an environmentally responsible manner at the lowest possible cost.

Utility planning is an iterative process. Consistent with good utility practice, Hydro will continue to regularly assess load growth, asset performance, and the demand for energy and capacity. Following this process, Hydro will continue to make evidence-based decisions on future additional supply sources that are right for the people of the province. The solutions presented in the 2024 Resource Plan are the next steps toward planning for the future, resulting in applications to build additional generation resources to meet increased electricity demand and maintain current reliability.

Many solutions will be required over the coming decade—and beyond. It is becoming increasingly clear that additional supply resources above and beyond those Hydro is currently progressing will be necessary to meet the growing demands of the electrical system.

This iterative analysis and the urgent system expansion required is not a challenge that customers, utilities, and regulators in Newfoundland and Labrador will face alone. Across the country, utilities have to balance unprecedented growth at exponential speed as a result of electrification and decarbonization of the electricity grid. Through upfront planning, Hydro is ensuring it can confidently take action at the speed required to ensure reliability for customers.

> ***"Better planning creates greater certainty for utilities, developers, and investors. This can significantly reduce financial risks and, by extension, the cost of capital."[8]***
>
> **CANADA ELECTRICITY ADVISORY COUNCIL**

Hydro's 2024 Resource Plan reflects a moment in time—considering presently available information. Hydro will utilize this plan to make its first decisions to power the province and present its applications to the Board for approval of projects representing the Minimum Investment Required in late 2024 or early 2025.

These are the same first steps required to meet the Reference Case, which includes the advancement of the second capacity resource to mitigate the risk of supply shortage. Advancing the second capacity option has a material benefit to the reliability of the Island Interconnected System in the event of a prolonged LIL bipole outage; it is also beneficial to ensure the retirement of aging thermal assets as planned. Lastly, if the Reference Case load forecast were to increase and/or the LIL bipole EqFOR is higher than 1%, both capacity options are required.

At present, there are alternatives to satisfy the incremental load growth between the Minimum Investment Required and the Reference Case. Hydro is taking the appropriate actions to be ready to expedite additional supply should the expected case materialize.

Hydro will continue to analyze trends and forecasted growth, engage and consider customers in decisions affecting the electricity system, and collaborate with all parties to realize the vision for a clean energy future. The need for collaboration amongst relevant parties, efficient processes, and timely action is paramount to Newfoundland and Labrador's continued success in being a Canadian renewable energy leader while continuing to deliver the reliable service that customers expect.

[8] "Powering Canada: A blueprint for success," Canada Electricity Advisory Council, May 2024. https://natural-resources.canada.ca/our-natural-resources/energy-sources-distribution/electricity-infrastructure/the-canada-electricity-advisory-council/powering-canada-blueprint-for-success/25863

Contents

Executive Summary i

Initial Focus on the Island i

Listening to Electricity Customers i

Growth in System Demand iii

Load Forecasting iii

Reliability iv

Prudent Minimum Investment Required Approach v

Actions Taken to Advance Hydro's Plan vi

A Collective Responsibility for Urgent Action—Now and in the Future vii

1.0 Introduction 1

1.1 Power the Province: 2024 Resource Adequacy Plan 2

1.1.1 2023 and 2024 Filings 3

1.2 Third-Party Reviews and Lessons Learned 4

2.0 Current Landscape 5

2.1 Global Context 6

2.2 Canadian Context 7

2.2.1 Canadian Utility Transformation 7

2.2.2 Government of Canada – Draft *CER* 11

2.3 Provincial Context 12

2.3.1 Net-Zero Province by 2050 12

2.3.2 Province's Renewable Energy Plan 13

2.3.3 Emergent Green Energy Economy – Wind 14

2.3.4 Legislative Obligations 14

2.3.5 Provincial Electricity System and Assets 15

2.3.6 Immigration and Population Growth 18

2.3.7 Energy Cost Considerations 18

3.0 Steps Taken by Hydro 20

3.1 ECDM Programming 20

3.2 Capacity Assistance 21

3.3 Public and Customer Engagement 22

3.4 Monitoring LIL Reliability 22
3.5 Bridging the Gap to New Assets 24
3.6 Understanding Provincial Load Growth 25
3.6.1 Island Interconnected System 25
3.6.2 Labrador Interconnected System 27
4.0 Regulatory Process 28
5.0 Expansion Plan Analysis 30
5.1 Determining the Needs of the Electrical System 30
5.1.1 Load Forecast 31
5.1.2 Scenarios 33
5.2 Hydro's Supply Stack 34
5.2.1 Hydroelectric Generation Resources 35
5.2.2 Wind Generation Resources 36
5.2.3 CT Generation Resources 36
5.2.4 Battery Storage 39
5.2.5 Solar Generation 40
5.2.6 Capacity Assistance 40
5.2.7 ECDM 40
5.3 Transmission 42
5.3.1 Identifying and Addressing Bottlenecks 43
5.4 Expansion Plans Analysis Outcome 44
6.0 Hydro's Expansion Recommendation 45
6.1 Hydro's Plan: Minimum Investment Required 46
6.2 Meeting Reference Case Requirements 48
6.2.1 Alternative Technologies 49
7.0 Next Steps 51
7.1 Building Capability and Capacity 52
7.2 Major Projects Life Cycle 54
7.3 Current New Build Projects 56
7.3.1 Completion of Front-End Planning 56
7.4 Major Projects Challenges 58

7.4.1 Supply Chain Challenges 58
7.4.2 Approval Timeline Challenges 60
7.4.3 Resource Challenges 61
7.4.4 Organizational Readiness 61
7.5 A Collaborative Approach 62
8.0 Continued Resource Planning 63
9.0 Conclusion 64

1.0 Introduction

The *RRA Study Review* has been evolving since its start in 2018, particularly within the past 24 months, and so too has the industry and environment in which utilities operate. The dramatic societal shift towards cleaner sustainable energy sources is having major impacts on electricity grids and utility planning. Across the globe, utilities have to balance unprecedented growth at unprecedented speeds as a result of electrification and decarbonization of the grid.

Hydro's 2024 Resource Plan is filed as part of the ongoing *RRA Study Review*, which addresses Hydro's long-term approach to providing continued reliable service for its customers. The first installment of the RRA Study was filed with the Board in 2018 with updates provided in 2019, 2020, 2021, and 2022. The 2024 Resource Plan is the continuation of the resource planning process. It provides an in-depth analysis of how much electricity customers will need over the next ten years and identifies system requirements; it considers which Hydro assets should be maintained and if new assets are required to reliably meet the province's electricity demands. Hydro has worked with Daymark throughout the analysis; Daymark's role was to challenge Hydro to investigate alternative assumptions, solutions, and scenarios to test the results. Daymark concluded:

> Consistent with Hydro's stated goal of providing reasonable reliability at the lowest cost, Hydro has elected to pursue a minimum expansion strategy.
>
> While prudent in the short term, in the long-term, Daymark recommends that the Minimum Expansion Strategy be supported by the timely monitoring of load changes and resource capabilities along with the preplanning of additional expansion alternatives to enable accelerated deployment in the event additional need develops.[9]

Daymark's comments on Hydro's methodology are provided as Appendix A.

For this filing, the Island and Labrador Interconnected Systems have been assessed separately, focusing on the production of an Island Interconnected System Expansion Plan that satisfies both capacity and energy requirements. Further discussion of Hydro's planning criteria is included within Appendix B. New requests for large amounts of electricity in Labrador can involve both transmission and generation supply investments. Hydro meets regularly with various customers to understand and analyze customers' potential needs. Due to the potential resulting cost for customers, this is an iterative

[9] "2024 Reliability & Resource Adequacy Process Review," Daymark Energy Advisors, May 9, 2024, p. 10. (Appendix A).

feedback process with customers to refine opportunities for the future. Analysis regarding transmission options is progressing in accordance with the approved *NAP*,[10] with System Impact Studies underway for proponents wishing to proceed. Electricity generation options include both customer self-supply as well as supply from Hydro; this mix will continue to be considered, as customers' needs evolve.[11]

The sections that follow provide important context regarding the current landscape in which Hydro operates; this is key to understanding the underlying assumptions and analysis used to form Hydro's 2024 Resource Plan, including its Expansion Plan. Relevant global, national, and provincial policies; the status of the provincial electricity system; as well as Hydro's current assets and other key drivers of Hydro's load forecast along with the extensive work completed and steps taken by Hydro thus far all play a significant role in the recommendations and conclusions of Hydro's 2024 Resource Plan.

1.1 Power the Province: 2024 Resource Adequacy Plan

Utilities such as Hydro undertake resource planning as a continuous process, responding to a changing energy landscape of customer requirements, weather uncertainties, grid reliability, and evolving provincial priorities (e.g., economic growth, climate change, etc.).

Hydro's 2024 Resource Plan, as presented herein, covers the period through 2034 and includes an overview of the significant actions and analysis undertaken by Hydro to:

- Demonstrate the need to construct new generation to provide an adequate supply of electricity due to increasing load growth and reliability of supply; and
- Identify the viable supply options for electricity in line with Hydro's mandate under the *EPCA*.

As a result, Hydro has completed thorough and in-depth analyses to develop its Expansion Plan, included as Appendix C. The 2024 Expansion Plans consider many different generation options, including hydroelectric generation, CTs that can use renewable fuels, wind, BESS, solar, utilization of transmission options, and other potential resource alternatives required to meet anticipated system load growth and the reliability expectations defined in Appendix B. The 2024 Resource Plan also addresses the outstanding questions related to LIL reliability as well as the Holyrood TGS as a long-term standby option

[10] Newfoundland and Labrador Hydro (2020). *Network Additions Policy – Labrador Interconnected System*. https://nlhydro.com/wp-content/uploads/2021/03/Network-Additions-Policy.pdf
[11] Additional discussion regarding load growth and planning for the Labrador Interconnected System can be found in Section 3.6.2.

for the LIL. Hydro will continue to evaluate traditional and emerging solutions for its next and future iterations of resource planning.

1.1.1 2023 and 2024 Filings

Since the 2022 Update, Hydro has completed extensive analyses, assessed various scenarios, and thoroughly evaluated all options. The following technical reports and studies were filed by Hydro in 2023 and 2024, including those within this 2024 Resource Plan:

- 2023 Near-Term Reliability Report (June 2023);
- BESS Study (September 2023);
- CT Feasibility Study (September 2023);
- Summary of Findings from L3501/2 Failure Investigations (October 2023);
- Avalon Supply (Transmission) Study (October 2023);
- Pumped Storage at Existing Hydro Sites (October 2023);
- 2023 Near-Term Reliability Report (November 2023);
- Long-Term Load Forecast Report (March 2023);
- Bay d'Espoir Unit 7 Uprate Study (July 2024);[12]
- CT Options Report (July 2024);[13]
- Fuel Market Study (July 2024);[14] and
- Impact of Prolonged Loss of the LIL on Reservoir Levels (July 2024).[15]

The analyses and actions completed through these studies and reports have informed Hydro on key issues regarding viable available alternatives and technologies to serve increased load growth and support near-term reliability. For example, identifying alternatives and solutions viable in the short term and eliminating others not immediately viable due to technology limitations, lack of consistently proven application for the needs of the Island and/or affordability. Further, Hydro has identified solutions to

[12] Included as Attachment 2 to Appendix C.
[13] Included as Attachment 3 to Appendix C.
[14] Included as Attachment 4 to Appendix C.
[15] Included as Attachment 5 to Appendix C.

monitor and seek updates on any emerging and alternative technology trends and associated affordability.

Through this analysis, Hydro has taken the necessary action to achieve increased clarity on the uncertainties highlighted within the 2022 Update and gather evidence that justifies the simultaneous advancement of the most feasible options for detailed investigation and estimates.

1.2 Third-Party Reviews and Lessons Learned

Hydro completed a digital public engagement survey in January 2024, administered by a third party, with questions relating to reliability, cost, investment, growth, clean energy, and options for new sources of electricity. The public engagement process confirmed that the Muskrat Falls Project remains top of mind for customers. In filing the 2024 Resource Plan, Hydro is working to ensure appropriate scrutiny of its decisions while striving to honour the lessons learned from the past and make recommendations that are in the long-term best interest of all electricity customers in Newfoundland and Labrador.

The 2024 Resource Plan is part of the *RRA Study Review*, under the consideration of the Board in a transparent process. As a result, Hydro's plan for expansion will be open to scrutiny, ensure all reasonably available options are evaluated, and be accountable to Hydro's mandate to provide least-cost, reliable service in an environmentally responsible manner.

Hydro has undertaken significant work to evaluate all the alternatives and obtain clarity on key decisions to progress to the next phase of the process—the applications for new supply solutions. Through this ongoing work, Hydro intends to de-risk the major project decisions to mitigate cost and schedule overruns in the future by doing the right work upfront.

As detailed within the reports filed to date as part of the *RRA Study Review*, Hydro has engaged multiple independent third-party experts to provide analyses that assisted Hydro in determining the viable alternatives with which to proceed to FEED. Currently, Hydro is advancing through FEED and EA activities with the identified viable alternatives—this will ensure that a material percentage of the engineering work will be completed prior to a request for approval of costs by the Board within applications for new generation.

Proceeding with third-party assistance in developing FEED ensures Hydro and the relevant parties make informed decisions based on the best independently verified information available prior to significant investments during the construction phase of a project.

As such, Hydro's 2024 Resource Plan provides an opportunity for discussion with relevant parties on key decision inputs to be used in the future planning of the Newfoundland and Labrador Interconnected System.

Many solutions will be required over the coming decade—and beyond. Hydro is confident the required analyses and associated reporting on all options to the Board and parties to date have progressed such that applications for the first set of supply solutions will be made in late 2024 or early 2025.

The applications for supply solutions will confirm Hydro's analysis that the options identified are the best alternatives to meet its mandate of providing reliable electricity in an environmentally responsible manner at the lowest possible cost.

2.0 Current Landscape

Globally, nationally, and provincially, a significant energy transition is underway, which is driven by an unprecedented demand for renewable energy to assist in fighting climate change and achieving net-zero targets. Figure 3 shows the many factors that are driving the urgency to make decisions to meet the expected needs of all customers in Newfoundland and Labrador.

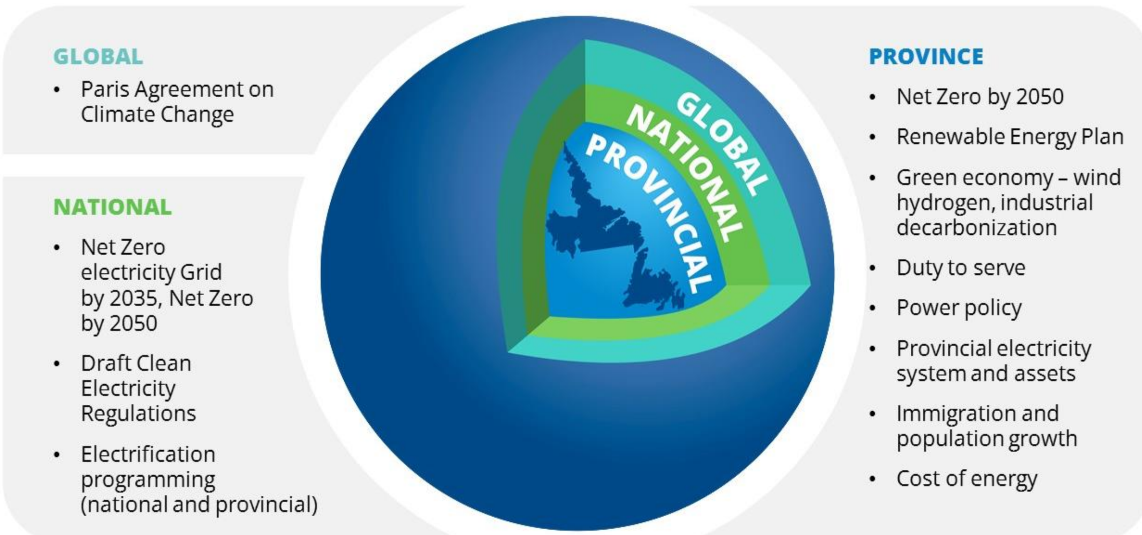


Figure 3: The Energy Landscape

2.1 Global Context

According to the International Energy Agency, global installation of renewables will need to more than triple to meet net zero by 2050 targets[16] and double for Canada.[17,18]

As climate change is one of the biggest challenges facing the world today, countries around the globe have made significant commitments to limit global warming and avoid the worst climate change impacts. This includes 195 countries signing the 2015 Paris Agreement on Climate Change;[19] 120 countries signing the 2021 Glasgow Climate Pact;[20] and over 120 countries, including all other G7 nations, committing to net-zero emissions by 2050.[21] These commitments have intensified global demand for renewable energy development, such as green electricity grids; electrifying fossil fuel-based

---

[16] "Net Zero Roadmap: A Global Pathway to Keep the 1.5 °C Goal in Reach – 2023 Update," International Energy Agency, September 2023. https://www.iea.org/reports/net-zero-roadmap-a-global-pathway-to-keep-the-15-0c-goal-in-reach

[17] "The Big Switch: Powering Canada's Net Zero Future," Canadian Climate Institute, May 2022. https://climateinstitute.ca/wp-content/uploads/2022/05/The-Big-Switch-May-4-2022.pdf

[18] "CanREA's 2050 Vision: Powering Canada's Journey to Net-Zero," Canadian Renewable Energy Association, November 2021. https://renewablesassociation.ca/wp-content/uploads/2021/11/CanREAs2050Vision_Nov2021_web.pdf

[19] "Paris Agreement - Status of Ratification," United Nations Climate Change. https://unfccc.int/process/the-paris-agreement/status-of-ratification#:~:text=The%20Paris%20Agreement%20is%20signed,the%20Paris%20Agreement%20was%20achieved.

[20] "COP26: Together for our planet," United Nations. https://www.un.org/en/climatechange/cop26

[21] "Net-zero emissions by 2050," Government of Canada, April 5, 2024. https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/net-zero-emissions-2050.html

transportation, space heating, and industrial processes; and power growing industries, such as green hydrogen and ammonia production.

2.2 Canadian Context

2.2.1 Canadian Utility Transformation

Due to Canada's abundance of renewable energy resources, including water used for hydroelectric generation, the Government of Canada indicates that an electricity grid powered by renewable energy will be the foundation for achieving net zero by its 2050 commitment,[22] setting an emissions reduction target of 40% to 45% below 2005 levels by 2030.[23] In support of this target, the Government of Canada has set a goal of a net-zero electricity system by 2035,[24] as well as requiring that 100% of car and passenger truck sales be zero-emission by 2035.[25]

According to the Government of Canada, the country will need to produce two or even three times the amount of emissions-free electricity to meet its net zero by 2050 target.[26]

> ***"In a net zero future, Canadian electricity demand will grow to be 1.6 to 2.1 times larger by 2050 compared to today. And to meet that demand, Canada's electricity generation capacity will need to be 2.2 to 3.4 times bigger than today."[27]***
>
> **CANADIAN CLIMATE INSTITUTE**

[22] "Draft *Clean Electricity Regulations*," Government of Canada, August 10, 2023. https://www.canada.ca/en/environment-climate-change/news/2023/08/draft-clean-electricity-regulations.html

[23] "2030 Emissions Reduction Plan – Canada's Next Steps for Clean Air and a Strong Economy," Government of Canada, March 29, 2022. https://www.canada.ca/en/environment-climate-change/news/2022/03/2030-emissions-reduction-plan--canadas-next-steps-for-clean-air-and-a-strong-economy.html

[24] "Canada launches consultations on a Clean Electricity Standard to achieve a net-zero emissions grid by 2035," Government of Canada, March 15, 2022. https://www.canada.ca/en/environment-climate-change/news/2022/03/canada-launches-consultations-on-a-clean-electricity-standard-to-achieve-a-net-zero-emissions-grid-by-2035.html

[25] "Building a green economy: Government of Canada to require 100% of car and passenger truck sales be zero-emission by 2035 in Canada," Government of Canada, June 29, 2021. https://www.canada.ca/en/transport-canada/news/2021/06/building-a-green-economy-government-of-canada-to-require-100-of-car-and-passenger-truck-sales-be-zero-emission-by-2035-in-canada.html

[26] "Clean Electricity," Government of Canada. https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/annex_clean_electricity.pdf

[27] "The Big Switch: Powering Canada's Net Zero Future," Canadian Climate Institute, May 2022. https://climateinstitute.ca/wp-content/uploads/2022/05/The-Big-Switch-May-4-2022.pdf

Due to the increasing demand for renewable energy and the growth of regional and national net-zero targets, utilities and governments across Canada have announced material changes to expand their electrical grids. In Hydro's review of jurisdictional spending across Canada, there have been several announcements through late 2023 and 2024, including:

- The 2024 federal budget announced its continued commitment to over $160 billion in investments, including a suite of major economic Investment Tax Credits aimed to attract investment through $93 billion in incentives by 2034–2035 (e.g., a 15% refundable tax credit rate for eligible investments in new equipment or refurbishment) as well as at least $20 billion from the Canada Infrastructure Bank to build major clean electricity and clean growth infrastructure projects.[28] These opportunities are available to a provincial Crown utility;
- Nova Scotia announced the "2030 Clean Power Plan" to add approximately 1,000 MW of new wind and 300 MW of solar via Net Metering by 2030; [29]
- Hydro-Québec announced its intent to spend $155 to $185 billion by 2035 to increase system capacity and reliability;[30]
- The Government of New Brunswick announced a plan to integrate 1,400 MW of new wind, 200 MW of grid-scale solar, 300 MW of behind-the-meter solar, and 600 MW of new nuclear by 2035;[31]
- BC Hydro announced $36 billion to expand its electricity system to meet industrial demands, including $10 billion for electrification and emissions-reduction projects;[32] and
- The Government of Ontario announced support to refurbish Niagara region hydroelectric generating stations at $1 billion—securing up to 1,700 MW of hydropower, equivalent to

[28] "Budget 2024: Fairness for Every Generation," Government of Canada, April 16, 2024. https://budget.canada.ca/2024/report-rapport/budget-2024.pdf
[29] "Nova Scotia's 2030 Clean Power Plan," Nova Scotia Department of Natural Resources and Renewables, October 14, 2023. https://beta.novascotia.ca/sites/default/files/documents/1-3582/nova-scotia-clean-power-plan-presentation-en.pdf#:~:text=Nova%20Scotia%27s%20Electricity%20Context,reach%2080%25%20renewables%20by%202030.&text=(from%2010.7%20MT%20in%202005).&text=closure%20and%20new%20Clean%20Electricity%20Regulations.
[30] "Action Plan 2035: Towards a Decarbonized and Prosperous Québec," Hydro-Québec. https://www.hydroquebec.com/data/a-propos/pdf/plan-summary.pdf
[31] "Powering our Economy and the World with Clean Energy: Our Path Forward To 2035," Province of New Brunswick, December 12, 2023. https://www2.gnb.ca/content/dam/gnb/Corporate/Promo/energy-energie/GNB-CleanEnergy.pdf
[32] "Premier announces new actions to build electricity system, create jobs," Government of British Columbia, January 16, 2024. https://news.gov.bc.ca/releases/2024EMLI0002-000049

powering 1.7 million homes—helping to meet increasing demand from electrification and load growth.[33]

To accommodate such significant electricity expansion within the timelines needed to achieve the anticipated load growth and provincial renewable energy targets, Canadian governments, utilities, and stakeholders are recognizing the need for changes to the planning and approval of these projects, including through investment, legislation, and regulation. In its 2024 State of the Industry report, EC stated, “Provincial governments need to go beyond traditional electricity-related statutes . . . and issue more timely policy directives or mandate letters to encourage regulatory innovation and related processes.”[34] Examples of such initiatives include:

- The Government of Nova Scotia’s establishment of the Nova Scotia Clean Electricity Solutions Task Force, which provides recommendations to modernize its electricity system, ensuring the system has the capacity needed to reach the province’s climate change goals. This includes the creation of a new *Energy Modernization Act*, which will tie climate change goals to energy sector regulation;[35]
- The Government of Ontario has introduced Bill 165 (*Keeping Energy Costs Down Act, 2024)* within the legislature, which makes various amendments to the *Ontario Energy Board Act, 1998*. A new section authorizes the Minister, subject to the Lieutenant Governor in Council’s approval, to issue directives requiring the Ontario Energy Board to hold a generic hearing to determine any matter respecting natural gas or electricity over which it has jurisdiction that the directives specify. The directives may address various matters respecting the hearing, including setting out timelines and procedural requirements;[36] and
- On January 15, 2024, British Columbia's Premier issued a mandate letter to its Minister of Energy, Mines and Low Carbon Innovation, directing them to “Work with the BC Utilities

[33] “Ontario plans to refurbish Niagara Region electricity generating plants for $1 billion,” Link2Build, April 18, 2024. https://link2build.ca/news/articles/2024/april/ontario-plans-to-refurbish-niagara-region-electricity-generating-plants-for-1-billion/
[34] “Getting to Yes: The State of the Canadian Electricity Industry 2024,” Electricity Canada, March 22, 2024, p. 15. https://issuu.com/canadianelectricityassociation/docs/soti_2024_e
[35] “Statement on Report from Clean Electricity Solutions Task Force,” Government of Nova Scotia, February 23, 2024. https://news.novascotia.ca/en/2024/02/23/statement-report-clean-electricity-solutions-task-force
[36] Bill 165, *An Act to amend the Ontario Energy Board Act, 1998 respecting certain Board proceedings and related matters*, 3rd Reading, Ontario, 2024. https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-165

Commission to identify an appropriate role for the Commission in supporting B.C.'s clean energy transition, in alignment with our province's climate goals to achieve net zero by 2050 and affordability objectives."[37]

The Canada Electricity Advisory Council, an independent body of electricity sector leaders convened by the Minister of Natural Resources to advise on policies to enable net zero in the electricity sector, released its final report in May 2024. The report, "Powering Canada: A blueprint for success," cites four cornerstones to enable the success of the energy transition in every region of Canada: speed, affordability, reliability and Indigenous participation.[38]

> ***"Speed: To achieve its goals, Canada needs to rapidly expand its clean electricity infrastructure. That simply will not happen without measures designed to attract capital, involve Indigenous Nations and communities, and, critically, recalibrate project review and approval processes across the country and at every level of government to enable more clean electricity."[39]***
>
> **CANADA ELECTRICITY ADVISORY COUNCIL**

2.2.1.1 Supply Chain

To achieve the grid expansion needed, while protecting ratepayers from costs, global leaders are urging prompt decision-making. Increasing global and national demand for clean energy has already placed pressure on supply chains, driving up prices. The demand for clean energy also drives further competition for resources amongst utilities across the country—including parts, equipment, consultants, and labour—as they strive to meet build commitments to enable compliance with regulations. Clearly, increased competition will drive costs and extend schedules. Slow decision-making will place jurisdictions at the end of the supply chain line and such jurisdictions will have the highest costs as a result.

[37] David Eby, KC, letter, January 15, 2024. https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/premier-cabinet-mlas/minister-letter/emli_-_osborne.pdf

[38] "Powering Canada: A blueprint for success," Canada Electricity Advisory Council, May 2024. https://natural-resources.canada.ca/our-natural-resources/energy-sources-distribution/electricity-infrastructure/the-canada-electricity-advisory-council/powering-canada-blueprint-for-success/25863

[39] "Powering Canada: A blueprint for success," Canada Electricity Advisory Council, May 2024. https://natural-resources.canada.ca/our-natural-resources/energy-sources-distribution/electricity-infrastructure/the-canada-electricity-advisory-council/powering-canada-blueprint-for-success/25863

As this trend is expected to continue and intensify, it is imperative to make informed and prompt decisions, as delays will result in increasing costs to electricity customers, with these costs intensifying as the delay grows longer. Schedules will also lengthen, as jurisdictions that move slowly will be at the end of the supply chain line. In addition to modernizing review and approval processes to reflect current day risks, utilities may also need to explore new strategies and approaches to mitigate these cost pressures, such as pre-purchasing a slot in an assembly line before final decisions/specifications are known, to de-risk the project schedule and to control costs.

> ***"The world is already seeing the risks of tight supply chains, which have pushed up clean energy technology prices in recent years, making countries' clean energy transitions more difficult and costly."[40]***
>
> **INTERNATIONAL ENERGY AGENCY**

2.2.2 Government of Canada – Draft *CER*

According to the Government of Canada, to achieve net zero by 2050, energy-intensive activities—such as transportation, heating and cooling of buildings, and various industrial processes—will need to be electrified by a low-carbon grid.[41]

As such, on August 19, 2023, the Government of Canada published its draft *CER,* establishing performance standards to reduce GHG emissions from fossil fuel-generated electricity starting in 2035.[42] As outlined by the Government of Canada, these regulations are an integral part of Canada's "2030 Emissions Reduction Plan" to help the country reach its emissions reduction target of 40% to 45% below 2005 levels by 2030, and net-zero emissions by 2050.[43]

While the final regulations are expected to be published in the Canada Gazette, Part II, later in 2024, the Government of Canada indicates the regulations will include flexibilities so that provinces and utilities

[40] "Energy Technology Perspectives 2023," International Energy Agency, January 12, 2023. https://www.iea.org/reports/energy-technology-perspectives-2023
[41] "Net-zero emissions by 2050," Government of Canada, April 5, 2024. https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/net-zero-emissions-2050.html
[42] "Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations," Government of Canada, August 19, 2023. https://www.gazette.gc.ca/rp-pr/p1/2023/2023-08-19/html/reg1-eng.html
[43] "2030 Emissions Reduction Plan: Clean Air, Strong Economy," Government of Canada, December 7, 2023. https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030.html

are able to maintain reliable and affordable electricity for Canadians, including exemptions for isolated systems and other exceptions that may apply to Hydro's needs. The draft *CER* also recognize that certain jurisdictions may be required to maintain fossil fuel-utilizing facilities as part of their fleet for various reasons, such as for peak and emergency circumstances.[44]

The *CER* are a key consideration in Hydro's evaluation of potential new sources of generation; Hydro will continue to ensure that any supply option being proposed complies with the draft regulations.

2.3 Provincial Context

2.3.1 Net-Zero Province by 2050

According to the GNL, the province emits approximately 8.3 million tonnes of GHG emissions per year.[45] Approximately 90% of this occurs as a result of burning fossil fuels, primarily via transportation, large industries, and buildings.[46]

GNL has committed to several renewable energy targets for the province, including the reduction of provincial GHG emissions by 30% below 2005 levels by 2030[47] and net-zero emissions by 2050.

Newfoundland and Labrador is fortunate to have a grid with some of the highest penetration of renewable electricity sources in Canada, with 93% of the energy generated in 2023 coming from renewable energy resources (primarily hydro), compared to the Canadian national average of 71%.[48] As such, GNL has identified amplified use of the province's renewable electricity grid as key to achieving net zero by 2050. Specifically, by enabling electrifying transportation, space heating, and industrial processes to lower provincial GHG emissions.[49]

---

[44] The draft *CER* characterize an emergency circumstance as one that arises due to an extraordinary, unforeseen, and irresistible event.
[45] "Minister Davis Highlights New Climate Change Action Plan Consultations," Government of Newfoundland and Labrador, November 15, 2023.
https://www.gov.nl.ca/releases/2023/ecc/1115n04/
[46] "Climate Change Action Plan 2019–2024: Midterm Update," Government of Newfoundland and Labrador, December 20, 2021.
https://www.gov.nl.ca/ecc/files/ClimateChangeActionPlan_MidtermUpdate.pdf
[47] "The Way Forward on Climate Change in Newfoundland and Labrador," Government of Newfoundland Labrador, March 1, 2019.
https://www.gov.nl.ca/ecc/files/publications-the-way-forward-climate-change.pdf
[48] "Energy Fact Book 2023–2024," Natural Resources Canada, October 2023.
https://publications.gc.ca/collections/collection_2023/rncan-nrcan/M136-1-2023-eng.pdf
[49] "Climate Change Action Plan 2019–2024: Midterm Update," Government of Newfoundland and Labrador, December 20, 2021.
https://www.gov.nl.ca/ecc/files/ClimateChangeActionPlan_MidtermUpdate.pdf

To date, GNL has established several programs and policies to increase the use of the renewable electricity grid, including for:

- Transportation: Providing a rebate of up to $2,500 for residents who purchased or leased an EV, to alleviate some of the upfront costs of ownership, with over 1,000 rebates provided since 2021;
- Buildings: Electrifying approximately 50 provincial government buildings, schools, post-secondary buildings, hospitals, and other medical facilities; and
- Homes: Electrifying over 2,500 oil-heated homes.

In addition to the impact this programming has had on the province's current electricity load, Hydro forecasts this amount will continue to grow over time as GNL enhances its policies and programs in support of net zero. This includes GNL's upcoming Climate Change Mitigation Action Plan (2025–2030), which aims to reduce GHG emissions to achieve the province's 2030 GHG reduction target, establish foundational actions for net-zero emissions by 2050, and support the transition to a low carbon economy.[50]

2.3.2 Province's Renewable Energy Plan

GNL recognizes the province's abundant renewable energy resources well-position it to meet net-zero commitments, fight climate change, and grow clean energy jobs and economic development. As such, in December 2021, GNL released the province's five-year renewable energy plan, "Maximizing Our Renewable Future,"[51] providing a sustainable long-term vision for the province to maximize its renewable energy future. Hydro is identified as a lead/support for a number of the initiatives in this plan, including enhancing understanding of market opportunities for renewable energy resources; supporting the industry in transitioning to renewable energy; increasing electrification of EVs and oil-fueled space heating; and leveraging federal funds to enhance the province's grid and transmission system, maximizing the efficient use of and value from the province's renewable energy resources.

[50] "Provincial Government Begins Public Engagement for New Climate Change Action Plans," Government of Newfoundland and Labrador, November 1, 2023.
https://www.gov.nl.ca/releases/2023/ecc/1101n03/
[51] "Maximizing Our Renewable Future: A Plan for Development of the Renewable Energy Industry in Newfoundland and Labrador, Government of Newfoundland and Labrador, December 16, 2021.
https://www.gov.nl.ca/iet/files/Renewable-Energy-Plan-Final.pdf

2.3.3 Emergent Green Energy Economy – Wind

Newfoundland and Labrador's abundance of undeveloped renewable energy resources well-positions the province to maximize economic development opportunities in the growing green energy economy. This includes supporting the emerging wind-powered hydrogen production industry, as well as enabling the private industry to assist in meeting the province's demand for clean energy. As such, care must be taken to ensure Hydro's next electricity generation decisions consider the emerging wind-hydrogen industry's need for firm energy, as well as enabling wind supply options from private companies, also known as Independent Power Producers.

On May 14, 2024, GNL announced the province's Hydrogen Development Action Plan, which is its next step in enabling the development of a green hydrogen and ammonia production industry in the province through the use of renewable energy resources, including wind. The plan will complement the Renewable Energy Plan and the Climate Change Action Plan, further advancing the province's status as a Clean Energy Centre of Excellence and global clean energy supplier.[52]

Further industrial activity is anticipated from hydrogen developments in 2028; it is also assumed there will be an additional incremental industrial load of 10 MW and up to 40 MW of firm demand through 2034. Hydro has and will continue to meet with numerous proponents to understand their progress and assess both the impacts and the opportunities on the grid as various projects advance. As this industry is expected to continue to evolve, Hydro will monitor closely and adjust forecasts as required.

2.3.4 Legislative Obligations

2.3.4.1 Duty to Serve

Under the *Act*, Hydro has a legal obligation to supply electrical energy to customers.[53] As electricity demand grows, Hydro needs to both construct and contract new sources of electricity generation to ensure an adequate supply for the provincial electricity grid. Further, under the *Act*, Hydro is regulated by the Board, which reviews and determines whether the electricity rates and capital expenditures proposed by Hydro will be approved.

[52] "Minister Parsons Launches Hydrogen Development Action Plan for Newfoundland and Labrador," Government of Newfoundland and Labrador, May 14, 2024. https://www.gov.nl.ca/releases/2024/iet/0514n01/
[53] *Public Utilities Act*, RSNL 1990, c P-47, s 37.

2.3.4.2 Power Policy

The province's power policy is outlined in legislation via the *EPCA*. In 2023, GNL revised Section 3(b)(iii) of the *EPCA* to expand the power policy of the province such that environmental considerations would be included in decision-making. Specifically, in a manner "that would result in power being delivered to consumers in the province at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service, as shown in Figure 4."[54,55]

Figure 4: Key Considerations of the Resource Plan

2.3.5 Provincial Electricity System and Assets

Newfoundland and Labrador's population of approximately 540,600[56] people are served by two utilities—the NL Utilities. Crown-owned Hydro generates the majority of the province's electricity, transmitting it through high-voltage transmission lines, and provides some distribution to Island areas not served by Newfoundland Power. Hydro also provides all electricity service to customers in Labrador. Investor-owned utility Newfoundland Power purchases the majority of its electricity (93%) from Hydro, which is distributed to customers on the Island.

---

[54] Bill 34, *An Act To Amend The Electrical Power Control Act, 1994 And The Public Utilities Act*, (assented to May 25, 2023), Newfoundland and Labrador, c 10. https://www.assembly.nl.ca/HouseBusiness/Bills/ga50session2/bill2334.htm
[55] *Electrical Power Control Act, 1994*, SNL 1994, c E-5.1, s 3(b)(iii).
[56] "Population stood at 540,552 as of January 1, 2024," Government of Newfoundland and Labrador. https://www.gov.nl.ca/fin/economics/eb-population/

Reliability of service is integral to the mandate of Hydro, with the majority of capital expenditures being partially related to maintaining or improving reliability. Hydro notes that its historical reliability trends have remained relatively flat since 2017, which is both reflective of Hydro's overall capital investment strategy and consistent with Hydro's efforts to balance reliability and cost. Maintaining current levels of reliability is becoming increasingly challenging, as many of Hydro's major assets are at either the beginning or the end of their life cycle, which is when failures are most likely.

This phenomenon is known as the "bathtub curve." This concept, which theorizes a relationship between equipment age and failures, has been presented by Liberty in previous reliability assessments.

> ***"Equipment failures in relation to equipment age generally exhibit a 'bathtub-shaped curve.' Incidents of failure tend to be high when equipment is new and again after 30-50 years, depending on equipment type."[57]***
>
> **LIBERTY CONSULTING GROUP**

As shown in Figure 5, the bathtub curve has three regions—the first has a decreasing failure rate due to early failures, which are found and corrected (contributing to improved reliability), the middle is a constant failure rate due to the normalized frequency of expected failures, and the last is an increasing failure rate due to end-of-life failures.

Figure 5: Bathtub Curve[58]

[57] "Supply Issues and Power Outages Review: Island Interconnected System – Executive Summary of Interim Report," The Liberty Consulting Group, April 24, 2014, sec. D, p. 57.
http://www.pub.nl.ca/applications/IslandInterconnectedSystem/files/reports/LibertyInterimReportApril24-2014.pdf
[58] James Carroll, Alasdair MacDonald, Oswaldo Barrera Martin, David McMillan, and Roozbeh Bakhshi "Offshore Wind Turbine Sub-Assembly Failure Rates Through Time," November 2015.
https://www.researchgate.net/publication/305000920_Offshore_Wind_Turbine_Sub-Assembly_Failure_Rates_Through_Time

In the early stages of its operation, as is normal for the operation of assets early in life, the current reliability of the LIL is anticipated to be lower than in the long term, due to failures associated with new assets (e.g., due to manufacturing issues or defective components). The LIL was officially commissioned on April 14, 2023; since that time, the LIL has been in service and successfully providing power to the provincial grid. The LIL is critical to the supply of the Island Interconnected System, as it carries power from Muskrat Falls to the Island, which helps to limit the thermal generation required from the Holyrood TGS. As such, there is a need to act quickly to get new assets in place as soon as possible and ensure there is appropriate overlap (bridging) of old assets until new assets are proven reliable.

Hydro also has aging assets that are within the third region of the bathtub curve. For example, the Holyrood TGS is currently a critical part of Hydro's Island Interconnected System; it has an installed capacity of 490 MW, with three oil-fired generating units, which range from 45 to 53 years old. As stated in the 2022 Update, Hydro has determined that maintaining the operation of the Holyrood TGS is not an appropriate long-term standby option; however, it could meet the need for backup generation to support the LIL until new sources of generation are available. To that end, Hydro recommends continued investment in the Holyrood TGS, the Hardwoods GT, and the Stephenville GT during the Bridging Period to ensure reliable operation in support of the Island Interconnected System in the event of a LIL outage. Continued use of the Holyrood TGS in both the near and longer term requires investment and attention, due to concerns related to reliability—as failures are becoming more and more likely with age, cost-effectiveness (as continuing the operation and maintenance of Holyrood TGS requires significant investment), and environment (as it will not be compliant with the *CER* in 2035).

Brattle has recognized the challenge of having assets on both sides of this curve, particularly in the face of climate change and during a time of intense industry and societal change, stating:

> ***"Managing more frequent and extreme weather events and replacing aging infrastructure is occurring at the same time as rapid grid expansion, putting pressure on utilities to meet multiple concurrent priorities."***[59]
>
> **THE BRATTLE GROUP**

[59] "Electricity in Canada: Always On," The Brattle Group, April 24, 2024, p. 6. https://issuu.com/canadianelectricityassociation/docs/electricity_in_canada_alwayson_4-24-2024_2_1_

2.3.6 Immigration and Population Growth

The provincial population is forecast to continue to experience strong growth, following an actual increase of approximately 7,022, or 1.3% from July 2022 to July 2023. This recent increase was the largest annual population increase since 1972.[60] Hydro's 2023 load forecast scenarios assume provincial population growth will continue, increasing between 1.5% and 5.3% by 2034.[61] According to GNL, the number of permanent residents in the province increased by 2,055 in 2021 and 3,495 in 2022,[62] with subsequent targets outlined in Table 1. Hydro's role is critical in supporting provincial policies related to increasing immigration and population.[63] Hydro expects these efforts will further increase demand on the province's electricity grid and must invest in the electricity grid to ensure adequate supply.

Table 1: GNL 2023–2025 Immigration Targets[64]

Year	New Permanent Residents
2023	3,950
2024	4,500
2025	5,100

2.3.7 Energy Cost Considerations

According to the Government of Canada, a growing number of studies have shown that deploying non-emitting electricity across the country can make energy use more affordable for Canadians.[65] For example, a recent analysis by the Canadian Climate Institute suggests, "Increased household electricity use will correspond with decreased use of gasoline, natural gas, and other fossil fuels. While spending on electricity will likely increase, total energy spending will decline."[66] Specifically, this modelling

[60] "2023 Economic Update," Government of Newfoundland and Labrador, p. 5. https://www.gov.nl.ca/fin/files/2023-Economic-Update.pdf
[61] Government of Newfoundland and Labrador 2023 Long-Term Economic Forecasts. Population growth assumptions for Slow Decarbonization and Accelerated Decarbonization forecasts are 1.5% and 5.3%, respectively.
[62] "2023–2026 Strategic Plan: Immigration, Population Growth and Skills," Government of Newfoundland and Labrador, p. 9. https://www.gov.nl.ca/ipgs/files/IPGSStrategicPlan2023-2026.pdf
[63] Specifically, GNL's Department of Immigration, Population Growth and Skills has a mandate to increase immigration and support population growth.
[64] "2023–2026 Strategic Plan: Immigration, Population Growth and Skills," Government of Newfoundland and Labrador. https://www.gov.nl.ca/ipgs/files/IPGSStrategicPlan2023-2026.pdf
[65] "Clean Electricity Regulations," Government of Canada, March 25, 2024. https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity-regulation.html
[66] "Electricity Affordability and Equity in Canada's Energy Transition," Canadian Climate Institute, September 2022. https://climateinstitute.ca/wp-content/uploads/2022/09/Electricity-and-equity-canadas-energy-transition.pdf

predicts that average household spending on total energy costs will decrease by 12% by 2050, as Canadians switch from fossil fuels to more efficient technologies, such as EVs and MSHPs.[67] Further, the electrification of transportation and heating can protect residents from exposure to volatile fossil-fuel markets.[68]

Conversely, EC has expressed concerns about the reliability and affordability implications of the *CER*, stating that the costs of compliance with the regulations for some provinces will be "extremely high," particularly for Alberta, Saskatchewan, Ontario, Nova Scotia, and New Brunswick.[69]

> ***"For Canada to remain competitive while making the transition to Net Zero by 2050, we must ensure electricity remains affordable and reliable while continuing to reduce and offset remaining emissions in the sector. We will also need to make sure that the system continues to grow, doubling or tripling the amount of electricity produced annually by 2050 to meet demand."[70]***
>
> **ELECTRICITY CANADA**

Consequently, as governments and utilities lay out their plans to comply with the regulations, rate pressure as a result of system expansion is not a challenge that customers, utilities, and regulators in Newfoundland and Labrador will face alone. Indeed, rates across the country are escalating by 7.3% on average in 2024. The rate mitigation plan announced by GNL on May 16, 2024 provides clarity of Hydro's annual electricity rate increases associated with the Muskrat Falls Project up to and including 2030. Hydro will work with GNL in advance of 2030 to determine future rate mitigation requirements once more information on the landscape of the electricity sector in that period is known and rate impacts of required system expansion are better understood.

[67] "Clean Electricity, Affordable Energy: How Federal and Provincial Governments Can Save Canadians Money On The Path To Net Zero," Climate Change Institute, June 2023. https://climateinstitute.ca/wp-content/uploads/2023/06/Clean-Electricity-Affordable-Energy.pdf
[68] Nichole Dusyk and Lasse Toft Christensen, "Why Canada's Energy Security Hinges on Renewables," International Institute for Sustainable Development, October 3, 2022. https://www.iisd.org/articles/deep-dive/canadian-energy-security-renewables
[69] "Clean Electricity Regulations – Electricity Canada Response," Electricity Canada, November 2, 2023, p. 3. https://www.electricity.ca/files/reports/Final-Electricity-Canada-CER-Response.pdf
[70] "Clean Electricity Regulations – Electricity Canada Response," Electricity Canada, November 2, 2023, p. 3. https://www.electricity.ca/files/reports/Final-Electricity-Canada-CER-Response.pdf

3.0 Steps Taken by Hydro

The policy drivers noted herein have dramatically increased the amount of electricity that will be needed by the people of the province over the next ten years. Hydro has taken extensive action in response to this growing demand already, and will continue to monitor the impact of public policy through its iterative planning process, using the 2024 Resource Plan to make important foundational steps in meeting energy demand within the province. The steps taken by Hydro to date in response to this growing demand and the regulatory process required for enabling further action are outlined in the sections that follow.

3.1 ECDM Programming

In 2023, Hydro continued to promote ECDM. ECDM is a component of resource planning—via joint utility programs offered by the NL Utilities through takeCHARGE as well as programming specifically targeted to Hydro's isolated and industrial customers. ECDM programs have been successful in providing education and fostering the development of a culture of energy conservation in the province.

ECDM is a critical component in managing the electrical system. Programs that promote efficiency and demand management directly benefit customers by reducing their energy consumption, resulting in cost savings for customers while also reducing demand on the system and the investment required to meet demand. Through the takeCHARGE partnership, the NL Utilities have already enabled a significant reduction in customer energy and demand requirements. Customers on the Island Interconnected System continue to benefit from multiple programs—including insulation and air sealing, HRVs, and various small technologies through instant rebates programs. The takeCHARGE partnership also serves the commercial sector through the Business Efficiency Program.

The NL Utilities continually evaluate ECDM programming to ensure positive system outcomes and cost-effectiveness. For example, takeCHARGE concluded certain programs in 2023, such as the Thermostat Program. These adjustments reflect the need for ECDM strategies to evolve in response to changing marginal costs and market dynamics.

In 2023, the combined takeCHARGE portfolio generated annual energy savings of over 33 GWh and reduced peak demand by approximately 14 MW.[71,72] These successes demonstrate the role of ECDM in deferring new infrastructure investments and managing system load effectively.

ECDM activities for 2023 included the continuation of residential and commercial rebate programs, the Isolated Communities Energy Efficiency Program, the Isolated System Business Efficiency Program, and the delivery of government-funded programs. Hydro, either directly or through the takeCHARGE partnership, delivered four government programs to customers, including the Low Carbon Economy Leadership Funding Program, EV Rebate Program, Oil to Electric Incentive Program, and Commercial EV Charger Rebate Program. These four programs were fully cost-recovered and required no ratepayer funds.

3.2 Capacity Assistance

A CAA provides generation from customers back to the electrical system during peak hours and periods of system constraint. This least-cost solution allows Hydro to avoid incurring higher costs as a result of building generation and avoid customer outages to manage peak load and maintain system integrity. Hydro and CBPP have been parties to a CAA for several years. In 2023, Hydro and CBPP entered into a fixed-price,[73] year-round CAA for a 15-year term, with CBPP providing up to 90 MW of capacity to Hydro in the winter and 50 MW in the summer. The fixed price for the duration of the CAA is lower than Hydro's forecasted cost of incremental generation, also known as the Marginal Cost of Capacity, during that time. Similarly, Hydro also has a CAA with Vale, which has been renewed on an annual basis for a capacity of 10.8 MW during the winter season.

---

[71] The "2023 Conservation, Demand Management and Electrification Report," Newfoundland Power Inc. April 17, 2023 included approximately 32 MWh of energy savings and 13 MW of peak demand savings.
[72] The "Electrification, Conservation and Demand Management Report For the Year Ended December 31, 2023," Newfoundland and Labrador Hydro, April 10, 2024 included approximately 2 MWh of energy savings and 1 MW of demand savings (rounded). http://www.pub.nf.ca/applications/NLH2021Capital/NLH2021Capital_SUPP_ExecuteProgram/report/From%20NLH%20-%202023%20Electrification,%20Conservation%20and%20Demand%20Management%20Report%20-%202024-04-10.PDF
[73] The fixed price is indexed to the CPI.

3.3 Public and Customer Engagement

In January 2024, Hydro launched a digital engagement initiative to inform its future decision-making processes. Hydro invited the public to participate by responding to an online survey (also available by phone). A follow-up survey with a feedback panel focused on reliability, cost, investment, growth, clean energy, and options for new sources of electricity. Hydro's engagement methodology is consistent with other utilities. More than 2,000 total responses were received to this engagement. A summary of the survey findings is included as Appendix D. Findings show respondents:

- Are concerned about the rising cost of living, including electricity rates;
- Prioritize low electricity rates over reliable and clean energy;
- Recognize that the province has a reliable system that is largely from renewables;
- Agree that Hydro needs to prepare for growing electricity needs;
- Differ in their preference for new electricity sources; and
- Feel they need additional information to provide an opinion.

Based on public input, Hydro's present recommendations are based on a conservative "Minimum Investment Required" approach—outlining what absolutely must be done to support reliability and prepare for load growth.

3.4 Monitoring LIL Reliability

In the 2022 Update, Hydro established the assumption that the LIL bipole EqFOR over the long term would be in the range of 1% to 10%. Hydro has been monitoring the asset's performance, including prior to commissioning, and has accrued some operational metrics and data to develop a LIL reliability measure, giving an early indication of performance. Hydro is pleased to report that the LIL bipole EqFOR from April 1, 2023 to June 1, 2024 was approximately 2.34%, which is well within the assumed long-term range, despite expectations of forced unavailability being higher early in commissioned operations.[74]

[74] LIL bipole EqFOR is calculated on a base LIL capacity of 700 MW. On a base capacity of 900 MW, LIL bipole EqFOR is calculated to be approximately 3.56%. Following the completion of the 900 MW test, all calculations will be adjusted to reflect the change in assumptions.

The LIL is an important transmission line for the provincial energy grid. Due to its power-carrying capacity, it will continue to be used to deliver a large portion of the winter peak energy to meet demand on the Island Interconnected System. Although the LIL is one transmission line, it runs through vastly different geographic and climatic conditions with large variations in terms of wind and ice. As a result, the line consists of many different types of towers, each designed for the specific conditions of each geographic region. Hydro has other transmission assets that are located and operating in areas of harsh terrain across the Island and Labrador. The LIL is also located and operates in areas of harsh terrain; it is subject to heavy wind and ice loads and experiences multiple winter seasons and weather events.

As is expected during early operation, Hydro has encountered unplanned outages to the LIL over the past three winters due to hardware damage caused by wind and ice during harsh weather events, particularly in the areas along the LIL where Hydro has observed microclimates. Hydro has also responded to failures due to local effects, including the galloping of overhead wires caused by the effects of wind in specific areas.

Climate change is also an important consideration for the reliability of the LIL, particularly as the data on which the assets were designed is now 15 years old. Hydro makes its operational decisions based on known inputs, such as weather data; however, Hydro and other utilities across Canada must also manage the increasing and changing impacts of climate change. Hydro is proactively studying climate change impacts and the associated increase in frequency and severity of weather events to assess the resilience of its entire infrastructure to adapt its planning, operation, and response accordingly.

Hydro is gaining operational experience with the LIL, monitoring performance, and implementing engineering solutions to improve reliability and performance effectively.

Hydro is taking proactive steps to mitigate the risk of customer impact and sustain the long-term reliability of the LIL. For example, in each instance of failure, root causes were determined through an extensive investigation process, immediate actions were taken to repair the damage, and recommendations were made to reduce the risk of customer impact in the future. Hydro is actively implementing the recommendations from completed investigations; a separate report on both its planned activities and actions taken to date was provided on July 9, 2024.

There are no long-term reliability implications on the LIL as a result of the events experienced to date; however, the damage experienced as a result of the harsh weather events over the past three winters affirms Hydro's plan to maintain the Holyrood TGS and the Hardwoods and Stephenville GTs through 2030 or until new assets are online and proven reliable.

3.5 Bridging the Gap to New Assets

Hydro's analysis continues to indicate that, due to load growth combined with the planned retirement of existing thermal assets, new on-Island capacity would be required within the next decade to meet the reliability planning criteria. Given these requirements, within its 2022 Update, Hydro developed an interim solution for the next ten years, the Bridging Period, during which Hydro will seek to develop new long-term sources of supply. The units at the Holyrood TGS and the Hardwoods GT shall remain available through the Bridging Period until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met. Further, in its November 2023 Near-Term Report, in light of a combination of load growth, FORs, and the risks of aging asset availability, Hydro determined that it would continue the operation of the Stephenville GT beyond 2024 and is recommending continued availability for the duration of the Bridging Period. Hydro will continue to make every effort to minimize the operation of these units.

In assessing the future of the Holyrood TGS, Hydro considered a third-party condition assessment conducted by Hatch,[75] supplemented with the federal requirement to achieve net-zero emissions in the electricity sector by 2035. As stated in the 2022 Update, Hydro has determined that maintaining the operation of the Holyrood TGS is not an appropriate long-term standby option; however, it could meet the need for backup generation to support the LIL until new sources of generation are available. To that end, Hydro recommends continued investment in the Holyrood TGS, the Hardwoods GT, and the Stephenville GT during the Bridging Period to ensure reliable operation in support of the Island Interconnected System in the event of a LIL outage. While the 2024 Resource Plan assumes a retirement date of 2030, Hydro has engaged a consultant to complete a refresh of the capital plan included in the

[75] Based on its 2020 assessment, Hatch concluded that the Holyrood TGS is generally in good operating condition and that, with required capital investments, it is a technically viable option for continued operation through 2030. The assessment noted that continued operation beyond 2030 might be viable, pending the results of a future condition assessment closer to 2030, should Hydro deem it necessary.

Holyrood Life Extension Condition Assessment[76] to assess the cost and viability of operation of Holyrood TGS beyond 2030,[77] to inform supply options in the event that some supply from Holyrood TGS is needed in advance of new generation.

3.6 Understanding Provincial Load Growth

As part of the 2024 Resource Plan, Hydro developed a range of load forecasts separately for the Island and the Labrador Interconnected Systems, as discussed in Section 5.1. In forecasting load growth, Hydro must consider several factors, including:

- Provincial economic forecasts, demonstrating increases in both housing starts and population growth;
- Newfoundland Power customer demand;
- Provincial and federal government policies and programs, such as incentives for oil-to-electric conversion, which are increasing demand for electricity as households switch from fossil fuels;
- EV adoption rates, which are forecasted to increase in coming years;
- Electricity rates and their impacts on consumer behaviours and load growth; and
- Industrial customer load growth, including the integration of new industries, expansion of existing industries, and electrification of existing industrial processes.

3.6.1 Island Interconnected System

Overall, the load forecast for the Island Interconnected System is showing growth across the provincial system through 2034, stemming from population growth, ongoing electrification activities to mitigate climate change driven by government policies, and firm requests from existing industrial customers.

Hydro has based its recommended 2024 Resource Plan on a slower rate of growth compared to the Reference Case load forecast; however, high load scenarios are quickly becoming a possibility, as the pace of electrification and industrial activity related to the decarbonization of energy, such as wind and

[76] "*Reliability and Resource Adequacy Study Review* – Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, March 31, 2022, att. 2.
[77] As noted in correspondence "*Reliability and Resource Adequacy Study Review* – Planned Reports, Studies and Analyses – Response to Further Comments and Directions," Newfoundland and Labrador Hydro, January 19, 2024, Hatch has been requested to assess life extension up to 2035; however, Hydro does not intend to keep Holyrood TGS in operation for this full period.

hydrogen activity, increases. Hydro will continue to monitor the pace of load growth through its iterative planning process, using the 2024 Resource Plan to make important foundational steps in meeting demand within the province as discussed in Section 5.4.

3.6.1.1 Industrial Load Growth

Industrial load on the Island Interconnected System is currently comprised of six customers, primarily operating in the mining, refining, and manufacturing sectors. In recent years, Newfoundland and Labrador has seen record-setting exploration expenditures in the mining sector,[78] in addition to a notable advancement in wind-hydrogen development projects. At a minimum, it is assumed all current industrial customers will remain and business activities will continue at currently forecasted levels. This estimated load would increase if one of the industrial customers partakes in decarbonization and/or electrification initiatives.

3.6.1.2 Wind Development Integration (Hydrogen/Ammonia)

GNL's Wind Development Process, which concluded in August 2023, was supported by Hydro to enable wind generation in the province. The evaluation of proposals led to four proponents being granted Crown Land Recommendation Letters—World Energy GH2, ABO Wind, EverWind, and Exploits Valley Renewable Energy Corp. A fifth proposal by Pattern Energy was not awarded a Crown Land Recommendation Letter; however, the advancement of development on private land in the Port of Argentia continues.

Information regarding electrical system technical requirements has been made available to proponents to ensure the reliable integration of their projects and wind self-supply into the system. The interconnection of new large customers will require System Impact Studies and new infrastructure dedicated to each, which will be fully funded by the respective proponents. To date, two of the five proponents have expressed the need to interconnect to the electricity grid; the System Impact Studies are ongoing.

If the System Impact Studies determine common infrastructure upgrades are required, the recovery of the associated construction costs from the proponents will require approval from the Board. Given the

[78] As shown in "Mineral Exploration Statistics," Government of Newfoundland and Labrador, annual mineral exploration expenditures in 2021, 2022, and 2023 are more than double those seen post 2013. This trend is expected to continue in 2024. https://www.geosurv.gov.nl.ca/minesen/exploration_stats/

uncertainty of load requirements and associated future load growth and demand, Hydro has incorporated a minimum of 10 MW of additional load starting in 2028 associated with wind hydrogen proponents in two scenarios within its forecast.

Hydro recognizes wind integration is likely to have a material impact on system operations and future resource additions. Wind generators will have generation in excess of their load for periods. This may be an effective means of meeting Hydro's future energy requirement and may provide marginal capacity to the system. Hydro is exploring the integration of wind power to meet future energy needs by collaborating with existing wind energy providers and engaging new proponents to understand how wind can contribute to a reliable and clean electricity system. As such, Hydro plans to issue an expression of interest for energy provision in 2025.

3.6.2 Labrador Interconnected System

Growth and variations in the load forecast for the Labrador Interconnected System are driven primarily by industrial customers. Accommodating industrial load growth in Labrador will require additional investment; current service requests from existing industrial customers would significantly increase load in this area. Given the size of the requests relative to the system capability along with the level of investment required to serve, Hydro is working closely with these industrial customers and operating under its *NAP*[79] to perform the necessary studies to better understand the impact of these requests on the transmission system. Each customer provides for input into each iteration based on their business decision making.

For the 2024 Resource Plan, similar to the Island Interconnected System, Hydro has conservatively reflected the low side of the potential outcomes within its load forecast. As customer's requests for service move further through the stages of Hydro's *NAP*, sensitivity forecasts will continue to be developed for use in various future planning studies. Hydro is working to responsibly balance the industrial applicants' requirements and manage bulk electrical system expansion while ensuring adherence to regulatory principles and Hydro's mandate to provide least-cost, reliable, environmentally responsible electricity. Hydro would proceed to seek approval from the Board, as required, for any necessary capital upgrades as a result of the ongoing studies.

[79] The purpose of the *NAP* is to limit rate increases resulting from investment in new transmission assets to serve new load requests.

Industrial load is growing in Labrador but the system impact is not yet known. Given the magnitude of requests, further study is required. Therefore, additional generation for the Labrador Interconnected System is not contemplated within Hydro's 2024 Resource Plan.

4.0 Regulatory Process

While most countries employ well-established approaches toward energy planning, global energy leaders are asserting that the current energy transition requires a reassessment of policy, regulatory, and investment planning methodology or global, national, and regional net-zero targets will not be met.[80,81] As such, provincial and territorial governments are central in developing policy, given their jurisdiction with respect to electricity systems.

"Acting early with smart policies can significantly reduce overall costs and make achieving net zero easier."[82]

CANADIAN CLIMATE INSTITUTE

As outlined by the Government of Canada, putting the country on a path to net zero requires significant and sustained private sector investment in clean electricity. For these investments to be made, Canada's regulatory system must be efficient and quicker.[83]

Further, EC has indicated that to adapt to changing conditions, electricity companies must be enabled to undertake greater risk-taking and innovation.

As such, EC recommends that provincial and territorial governments go beyond traditional electricity-related legislation and issue timely policy directives to allow regulators to consider innovative electricity sector projects to meet government policy objectives, enhance nimbleness and agility in the regulatory

[80] "Long-term energy planning," International Renewable Energy Agency. https://www.irena.org/Energy-Transition/Planning
[81] "Electricity Grids and Secure Energy Transitions: Enhancing the foundations of resilient, sustainable and affordable power systems," International Energy Agency, October 2023. Electricity Grids and Secure Energy Transitions – Analysis - IEA
[82] "The Big Switch: Powering Canada's Net Zero Future," Canadian Climate Institute, May 2022. https://climateinstitute.ca/wp-content/uploads/2022/05/The-Big-Switch-May-4-2022.pdf
[83] "Budget 2024: Fairness for Every Generation," Government of Canada, April 16, 2024. https://budget.canada.ca/2024/report-rapport/budget-2024.pdf

process, and reduce the time and costs associated with reviewing and approving projects that meet government policy objectives.[84]

> ***"Provincial regulators need to consider climate mitigation as much as electricity rate issues and consider the role of the electricity industry in meeting national decarbonization goals, and allow for innovation and "outside-the-box" proposals that would help achieve broader environmental, social, and economic goals."[85]***
>
> **ELECTRICITY CANADA**

Hydro supports this view and asserts that the traditional approach to utility planning and associated approval will not be effective in ensuring the province has the renewable energy resources available to meet the timing of the expected load growth, nor in meeting provincial or federal renewable energy targets. The power policy of the province, which both Hydro and the Board are legislatively obligated to implement, requires action be taken to ensure that there is an adequate supply of power to serve customers that is delivered to customers at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service. It is critical that the utilities and their regulator—i.e., Hydro, Newfoundland Power, and the Board—work collaboratively to achieve this goal to mitigate risks to customers due to insufficient supply and fully execute their collective responsibility regarding the power policy of the province.

> ***Load is increasing at a rapid pace, exceeding historical rates of load growth. There is a significant risk that demand may exceed available supply and could result in customer outages if the advancement of supply options is delayed. Hydro believes that urgent action by all parties is critical to meet the challenge ahead.***

[84] "Economic Regulatory System," Electricity Canada. https://www.electricity.ca/knowledge-centre/the-grid/regulatory/economic-regulatory-system/
[85] "Getting to Yes: The State of the Canadian Electricity Industry 2024," Electricity Canada, March 22, 2024, p. 15. https://issuu.com/canadianelectricityassociation/docs/soti_2024_e

5.0 Expansion Plan Analysis

In determining the needs of the electrical system, it is imperative to consider a range of realistic outcomes to enable Hydro to make prudent decisions that address both current and future load requirements.

As the primary generator and transmitter of power throughout Newfoundland and Labrador, Hydro plays a critical role in the province—reliably powering homes, businesses, and key industries. Hydro prioritizes its responsibility for the delivery of cost conscious electricity to customers while ensuring the maintenance and expansion of an efficient electricity system—both for today's needs and the rapidly increasing electrical requirements associated with the transition to a green economy. As electricity becomes increasingly integral to daily life, customers will become increasingly dependent on Hydro to meet their energy needs; it is essential that Hydro and the relevant parties make informed, timely and justified decisions.

Planning for the highest load growth scenarios without sufficient certainty may lead to overbuilding, unnecessarily increasing customer rates. Conversely, inaction and not advancing solutions when facing forecasted growth presents significant risks to long-term system reliability.

To mitigate these risks, Hydro has conducted extensive analyses of various potential outcomes. Considering the cost and technical considerations of each option in Hydro’s supply stack, Hydro’s Expansion Model identifies the least-cost options to reliably meet the requirements of the system under each scenario and in consideration of environmental impacts.

Hydro's 2024 Resource Plan evaluates the integration of new assets, system reliability, and the impact of electrification and decarbonization under multiple scenarios. It is evident that, regardless of the scenario, investments to increase electrical supply are necessary and appropriate to ensure continued reliable supply to customers in the province.

5.1 Determining the Needs of the Electrical System

The 2024 Resource Plan builds upon the analysis that Hydro has completed to date through the *RRA Study Review* to identify the needs of the electrical system for both capacity (Hydro’s ability to supply the maximum peak load on the system at a given moment in time) and energy (Hydro's ability to supply the total electrical power consumed by customers on the system throughout the year).

Hydro employs methodologies to model future system requirements consistent with good utility practice. Hydro's analysis spans multiple scenarios, each representing a different set of potential future demands. These scenarios are informed by different assumptions, such as the rate of load growth and the reliability of both existing and future assets, which influence future electrical needs and necessary investments. Such a methodical approach allows Hydro to comprehensively understand the potential impacts of various factors on system needs, thereby enabling informed and prudent decision-making for planning the system, based on scenarios that are most likely to occur.

For the 2024 Resource Plan, Hydro has selected eight scenarios, each reflecting a unique set of criteria and assumptions around reliability and load growth. In all eight scenarios, additional investment for generation resources is required to ensure adequate supply.

5.1.1 Load Forecast

As a first step, Hydro developed three forecasts for the 2024 Resource Plan to reflect the range of forecasted Island Interconnected System load requirements based on the drivers of load growth discussed in Section 3.6. All forecasts have inherent uncertainty. As a rule, in any utility, system-planning activities require consideration of a broad range of potential future outcomes to reflect uncertainty in the load forecast. This enables sound decision-making by demonstrating the resiliency of plans against a range of scenarios, allowing for increased certainty when making recommendations.

In its expert report on the load forecast methodology, Hydro's consultant Daymark concluded

> ***"Hydro's current load forecasting methodology reflects standard industry approaches for assessing potential growth. The approach and data are grounded in the realities Hydro and the industry must face."*** [86]
>
> **DAYMARK ENERGY ADVISORS**

[86] "R&RA 2024: Independent Load Forecasting Process Review," Daymark Energy Advisors, March 22, 2024, ch. II, sec. C, p. 15, filed as Attachment 1 to the "Long-Term Load Forecast Report – 2023," Newfoundland and Labrador Hydro, March 28, 2024.

The load forecast for the Island Interconnected System shows rapid growth over recent years, which is expected to continue through 2034 (i.e., the end of this planning period). The forecast load increases range for additional demand from 160 MW in the Slow Decarbonization forecast to 370 MW in the Accelerated Decarbonization forecast, as discussed in Hydro's 2023 Long-Term Load Forecast report.

Uncertainty remains in the later part of the forecast period as to the magnitude of industrial load growth on the Island Interconnected System; however, Hydro used the same industrial growth assumptions in both the Reference Case and Slow Decarbonization forecast.

The three forecasts for load requirements on the Island Interconnected System, as shown in Figure 6, are summarized herein.

Figure 6: Island Interconnected System Forecasts

- **Slow Decarbonization:** Considers more moderate decarbonization efforts and electrification of the transportation sector, lower population and housing starts, and increased electricity rates, resulting in a lower load forecast as compared to the Reference Case.
- **Reference Case:** Based upon the continuation of a steady level of decarbonization, driven primarily through government policy and programs, anticipated electrification of the transportation sector, and steady increase in population and housing starts.
- **Accelerated Decarbonization:** Assumes the accelerated decarbonization and electrification of the transportation sector, electricity rate assumptions consistent with the Reference Case,[87] higher population and housing starts, and an increase in industrial demand, resulting in a higher load forecast as compared to the Reference Case.

[87] The target mitigated rate Reference Case load forecast is 14.7¢/kWh, escalating by 2.25% per year, which is discussed further in Section 4.1 of Appendix B.

5.1.2 Scenarios

Hydro has established eight key scenarios as the basis for the analysis of the Expansion Plan. A summary of these scenarios follows; the scenarios are described in detail in Appendix C.

The variables that were altered between scenarios include:

- **Load Forecast:** This includes the establishment of an appropriate Reference Case, which reflects the expected, or most likely, future scenario based on current information, as well as Slow and Accelerated Decarbonization forecasts, which capture the breadth of potential future outcomes, highlighting the sensitivity of the load forecast to changes in key drivers.
- **Reliability Standards:** This is defined in terms of reliability metrics that aim to quantify system reliability in terms of expected hours of customer outages per year. While Hydro plans to maintain current levels of reliability, consideration of a range of reliability criteria allows Hydro to understand not only the investment required to maintain the current level of reliability but the investment required to achieve greater reliability consistent with industry benchmarks. The criteria selected are used to determine planning reserve requirements.
- **LIL Reliability:** While the LIL was commissioned in April 2023, this supply asset is in the early phase of its operation; Hydro continues to gain critical data and experience operating the asset. Therefore, Hydro has considered three levels of LIL reliability in its scenarios—representing 1%, 5%, and 10% LIL bipole EqFOR—to understand the impact of long-term LIL reliability on system needs. A separate scenario was also included for the LIL as an "Energy-Only" line even though it is not expected to operate as such.

Reliability standards and LIL reliability are used to calculate a required Planning Reserve Margin, or the amount of additional capacity required (expressed as a percentage of peak demand) required to ensure sufficient capacity is available when considering the impacts of asset reliability. Table 2 provides a summary of the underlying major inputs for each scenario.

Note that Scenario 1, or the Reference Case, has historically driven Expansion Plan requirements; however, Hydro has selected the more conservative Scenario 4 option, the Minimum Investment Required, to drive its 2024 Resource Plan.

Table 2: Summary of Major Inputs into Island Interconnected System Expansion Plan Key Scenarios

Scenario	Planning Reserve Margin[88] (%)	LIL Reliability (% EqFOR)	Load Forecast	Description
1: Reference Case	25.8	5	Reference	Incorporates assumptions that are considered most reasonable at this time by combining the Reference Case load forecasts and the reference LIL bipole EqFOR of 5%.
2: Higher Growth than Reference Case	25.8	5	Accelerated Decarbonization	Captures resource requirements if load growth on the Island accelerates more rapidly than anticipated.
3: Slower Growth than Reference Case	25.8	5	Slow Decarbonization	Captures resource requirements if load growth on the Island is slower than what is anticipated.
4: Minimum Investment Required	**17.1**	**1**	**Slow Decarbonization**	**Feeds Hydro's Expansion Plan. Identifies the Minimum Investment Required, assuming high LIL reliability and low load growth.**
5: Maximum Investment Required	29.1	10	Accelerated Decarbonization	Identifies the Maximum Investment Required, assuming low LIL reliability and high load growth.
6: Increased Electrification	17.1	1	Accelerated Decarbonization	Identifies what resource options are required mainly due to policy-driven load growth (i.e., electrification) by assuming high load growth and high LIL reliability.
7: Improved Reliability	35.1	5	Slow Decarbonization	Same assumptions as Scenario 3 but identifies the resources required to improve reliability consistent with industry benchmarks.
8: LIL Energy-Only	35.0	100[89]	Reference	Identifies the impacts to the system if the LIL were unavailable but does not reflect Hydro's operational experience for the LIL since it was commissioned.

5.2 Hydro's Supply Stack

To meet the future needs of the electrical system, Hydro has evaluated an extensive list of prospective supply resource additions, known as its supply stack, ranging from well-established technologies (such as wind, hydroelectric, and CT generation) to alternative technologies (such as utility-scale battery storage). Each potential supply option carries its own costs, implementation timeframes, and technical considerations, all of which must be considered in selecting those that are most suitable to address the needs of the system. As a result, not all of the options studied by Hydro are included as part of its

[88] The Planning Reserve Margins presented here are inclusive of losses.
[89] Assuming a 100% LIL bipole EqFOR is equivalent to assuming the LIL is an Energy-Only line and does not provide firm capacity for planning purposes.

recommended Expansion Plan as discussed in Section 6.0; however, Hydro will continue to evaluate the additions within its supply stack in future iterations of its resource plan.

The various resource options considered in Hydro's analysis are:

- Hydroelectric generation;
- Wind generation;
- Combustion turbine generation;
- Battery storage;
- Solar generation;
- Capacity assistance; and
- ECDM.

A summary of each is provided herein and described in more detail in Appendix C.

5.2.1 Hydroelectric Generation Resources

Hydroelectric generation resources account for the bulk of Hydro's existing supply and are globally considered well-established and reliable sources of capacity and energy. Hydro's hydroelectric supply stack consists of additions to existing facilities and the development of new facilities. New energy availability on the system is needed; however, additions to existing facilities utilizing existing reservoir storage do not introduce new energy availability on the system, as they use the same stored energy in the form of water in a reservoir system. In line with Hydro's mandate, hydroelectric generation alternatives also provide the additional benefit of enabling Hydro to perform planned maintenance outages on its equipment at a lower cost than thermal generation, thus allowing Hydro more flexibility to execute capital projects and maintain aging assets in future years. Hydroelectric generation alternatives were screened and ranked against criteria such as capacity, cost, environmental impacts, market conditions, etc. The resulting ranking in order of preference of prospective hydroelectric generation expansion alternatives is:

1) Addition of a new unit (Unit 8) in Bay d'Espoir (154 MW).
2) Addition of a new unit (Unit 3) in Cat Arm (68.4 MW).
3) Island Pond Development (36 MW).

4) Round Pond Development (18 MW).

5) Portland Creek Development (23 MW).

5.2.2 Wind Generation Resources

Newfoundland and Labrador is known for its strong potential for wind generation, leading to the prospective development of wind generation projects. Wind generation is a well-established technology that provides energy to the system; Hydro currently purchases wind energy produced by third-party suppliers in Fermeuse and St. Lawrence. Wind generation is considered an intermittent supply resource. Wind turbines require a minimum wind speed to produce energy. To prevent damage to the turbine, wind turbines are not operated when wind exceeds the turbines' design threshold. Therefore, while wind generation is a valuable resource for the provision of energy, the capacity added by wind generation is limited without the ability to store the energy produced and dispatch the energy when the system requires it unless paired with a storage system. For this reason, Hydro has considered large-scale wind generation resources in its supply stack,[90] to meet incremental energy needs while providing marginal capacity to the system.

As many sites on the Island could be geographically suitable for wind project development, no specific location has been identified for prospective wind development. Wind projects are actively in development in Newfoundland and Labrador; Hydro is closely monitoring these developments and assessing opportunity for potential supply relationships. An additional process is required to determine available alternatives for Hydro to purchase wind energy through both existing and potential proponents.

5.2.3 CT Generation Resources

CTs are well-established, reliable sources of capacity that utilize the combustion of fuels, such as diesel fuel, to produce electricity. Unlike traditional thermal generating stations, such as the Holyrood TGS, CTs can be designed with the ability to start quickly (within minutes) to support the system as required. CTs can also provide support to maintain stable system voltage, known as SC capability. Hydro currently has three CTs on the Island Interconnected System that provide backup reserves and peaking capability to meet demand when required.

[90] Large-scale wind generation would include plants exceeding 100 MW. Hydro's Expansion Model considers wind generation developments in increments of 100 MW.

Other CTs support regional reliability, such as the Happy Valley GT (owned by Hydro) and the CTs in Wesleyville and Greenhill (owned by Newfoundland Power). Based on long-term regional reliability requirements, Newfoundland Power has expressed to Hydro that there may be justification to replace these CTs and its thermal units in the Port aux Basques region. While such assessments are beyond the scope of the *RRA Study Review*, Hydro continues to work with Newfoundland Power to explore these solutions and understand their implications in terms of reliability and transmission upgrade requirements from a regional and provincial perspective.

Although current CTs utilize fossil fuels (which makes them carbon-emitting resources), due to their ability to start quickly, they do not need to operate continuously to support the system like traditional thermal resources. Therefore, the expected emissions from CT resources are considerably less than that of traditional thermal generating stations. For example, modelling the usage of CT resources following the retirement of the Holyrood TGS indicates that overall emissions associated with electricity generation could be reduced by over 80%.[91]

The Government of Canada's draft *CER* aims to limit the amount of generation produced by carbon-emitting sources within Canada. CTs may aid in the implementation of renewable supply resources by providing firm, reliable backup at times when intermittent renewable resources are not available; the regulations acknowledge the role that these resources will play in the transition to a clean electricity grid. Hydro has reviewed the draft regulations and believes that CT resources are a viable option for supply within this province while remaining fully compliant with the proposed regulations.

Hydro also plans on ensuring any CTs it would propose for integration into the grid would be able to utilize renewable fuels in the future.

5.2.3.1 Fuel Supply for CTs

Hydro has engaged external engineering consultants to conduct a review of available CT supply options—size, location, and system suitability, including constraints such as the availability of sufficient fuel supply. These assessments concluded that a CT of 150 MW capacity located at the Holyrood TGS

[91] Based on CT usage modelled in the Slow Decarbonization forecast, which assumes a high level of LIL reliability (1% LIL bipole EqFOR).

site is a viable option.[92] However, it was confirmed that larger CT operations in the range of 300 MW to 450 MW might be constrained by the available fuel supply.

Hydro contracted a Fuel Market Study, provided as Attachment 4 to Appendix C, which assessed the market forecast and availability for No. 2 Diesel fuel, reviewed existing supply chain processes to identify risks and potential improvements, outlined critical assets along the total supply chain, and provided an outlook of alternative fuel sources. This study concluded that the Canadian refining sector is facing structural and regulatory pressures that may reduce the availability of No. 2 Diesel fuel, contrasting with a more stable forecast for the U.S. refining sector. Regulatory initiatives in Canada aimed at reducing emissions will likely influence refinery operations, potentially leading to decreased production capacities by 2040, whereas U.S. refineries are expected to maintain production levels due to economic and security considerations.

The Fuel Market Study also highlights significant risks in the existing supply chain processes (including limited supplier responses to requests for proposals as well as logistical challenges in emergency fuel supply), recommending the development of a more diverse supplier pool, enhancements in storage and inventory management, and strategic placement of fuel reserves. It also evaluated alternative fuels, noting practical limitations for hydrogen and logistical challenges for biodiesel, liquid natural gas, and renewable fuels suggesting that, while these alternative fuels have potential, they may introduce logistical challenges, such as storage and sourcing large volumes that will need to be considered and understood in planning and developing alternative fueling options for CT resource in the future.

Overall, the Fuel Market Study emphasizes the need for strategic planning and adaptation to ensure a reliable fuel supply amidst evolving market and regulatory landscapes.

While Hydro's analysis suggests that current fuel markets can support the long-term operation of an additional 150 MW CT resource, further assessment is needed to ensure a stable and secure supply of fuel for electricity generation and to assess the viability of larger-scale CT operations as feasible, cost-effective resource options.

[92] "Combustion Turbine Feasibility Study – Overview," Newfoundland and Labrador Hydro, September 29, 2023.

Hydro has also completed an assessment of available CTs that may be previously used or available for immediate purchase to expedite the integration of new supply resources on the Island Interconnected System.

Through the CT Options Report, Hydro has confirmed that there are currently no suitable readily available CTs to enable an earlier replacement of the Holyrood TGS, Hardwoods GT, or the Stephenville GT.[93] Hydro is committed to continue observing the market to evaluate any options that may enable expedited integration of new supply resources.

The assessment of market availability completed by Hydro's consultant in the CT Options Report is provided as Attachment 3 to Appendix C.

5.2.4 Battery Storage

Utility-scale BESS are a relatively new technology that utilizes a network of large-scale batteries to store excess energy when available generation exceeds what is required by the system and discharges that energy to provide capacity to the system when required. BESS do not produce energy; rather, they store energy from other supply resources on the system, including intermittent generation, such as wind.

Existing battery technologies provide relatively short-duration capacity support to the system; they are typically designed to provide reserve capacity for a short duration, usually a few hours. The effectiveness of BESS is typically measured in terms of its ELCC, which measures the BESS' ability to provide its capacity to the system when the system requires it. ELCC is unique for each system and is dependent on the mix of assets on the system as well as the characteristics of the load on the system.

Hydro has studied BESS and considered 20 MW and 50 MW BESS installations with four-hour reserves in its supply stack;[94] however, Hydro must also consider the technical constraints of short-duration capacity reserves when considering these options. Longer-duration battery technologies are under development but have not been implemented and proven at a utility-scale.

[93] Hydro's requirements are outlined in the CT Options Report, including SC capability, fast start, and ability to accept both diesel fuel and renewables.
[94] "Battery Energy Storage System Report – Overview," Newfoundland and Labrador Hydro, September 29, 2023.

BESS have been implemented at a utility scale on other systems. Hydro expects that battery solutions will have a significant role in supporting future system operation, particularly as additional intermittent sources (such as wind) are integrated to meet growing demand. In the immediate term, however, the relatively short supply of battery durations would limit their effectiveness on Hydro's system. For example, the short duration of BESS limits their effectiveness during extended capacity shortfalls, such as in the event of an extended LIL outage. This reliability consideration would need to be addressed before the broad incorporation of battery solutions could be considered a viable capacity alternative.

5.2.5 Solar Generation

The solar power industry is growing in Canada and is relatively new in Newfoundland and Labrador. The viability of solar generation in Newfoundland and Labrador is limited, primarily due to extensive cloud cover, reduced daylight hours during the winter period, and the risk posed by snow cover on solar panels. Nonetheless, Hydro has included 20 MW solar installations in its supply stack for future consideration, the location of which would be determined should these resources present a viable supply option.

5.2.6 Capacity Assistance

Hydro continues to support system requirements by partnering with large industrial and commercial customers through CAAs to curtail their electricity usage during peak times. These agreements allow the utilization of customer-owned generation, such as generation from CBPP, to support the system when required. Through strategic partnerships with other large electricity customers, Hydro has accounted for over 130 MW of capacity assistance in its modelling, which represents approximately 7.5% of Island Interconnected System coincident system peak in 2025. This level of capacity assistance provides an equivalent system benefit to that of a large supply addition, such as a CT. Cost-effective capacity assistance has enabled Hydro to delay the implementation of new supply and will continue to play an active role in minimizing the investment required to meet demand on the system. In addition, Hydro is committed to seeking third-party support for additional capacity options.

5.2.7 ECDM

ECDM is crucial for optimizing Newfoundland and Labrador's electrical system, particularly as the region faces increasing energy and capacity requirements. Cost-effective ECDM programs directly benefit customers by reducing energy consumption (resulting in cost savings for customers) while also reducing the demand for energy and capacity on the system, thereby reducing the investment required to meet customer electricity requirements. By managing and reducing energy consumption and customer demand, ECDM programming serves to enhance system efficiency and mitigate the need for new supply resources; therefore, it is a priority for Hydro as it plans for the future of the electrical system.

The NL Utilities jointly deliver ECDM programming on the Island Interconnected System under the takeCHARGE partnership. Programming offered to customers under takeCHARGE must be shown to be cost effective.[95] An ECDM program (or portfolio of programs) is determined to be cost effective if the benefits from that program are greater than the costs of delivering that programming. Benefits from ECDM include avoided system costs (the marginal value of energy and capacity), which must be greater than the cost of implementing that same program.[96] In this regard, cost-effective ECDM programming represents a source of supply for Hydro that is less costly than its next supply option.

5.2.7.1 Electrification Programming

Hydro ensures the energy and capacity benefits from utility and customer ECDM activities, such as forecast impacts of takeCHARGE programming, utility demand response programming for EVs,[97] and customer conversions to heat pumps for space heating are all reflected in its load forecast.

As government policy and customer trends continue to advance electrification in Newfoundland and Labrador, Hydro is seeking opportunities for beneficial electrification, where benefits associated with new energy sales are maximized and customer behaviours are influenced to minimize system costs. Examples include Hydro's support of the takeCHARGE Electric Vehicle Load Management Pilot Project,[98] as shifting EV charging load to off-peak hours is critical to limiting system impacts from the electrification of the transportation sector. The results of this pilot project will help inform ECDM strategies and future programming as it relates to EVs.

---

[95] In *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 18(2016), Board of Commissioners of Public Utilities, June 8, 2016, the Board approved the use of the TRC Test and the PAC Test to demonstrate cost effectiveness.
[96] In the case of the PAC Test specifically. The TRC Test also considers supply side benefits in addition to participant costs and program costs.
[97] Hydro has assumed that it will be able to achieve 50% demand management for new light-duty EV charging demand on the system, shifting 50% of EV charging outside of the peak demand period. Newfoundland Power's ongoing EV Load Management Pilot Program, which studies various methods to encourage consumers to manage their demand during peak periods, will help inform how this target is achieved.
[98] "Electric Vehicle Load Management Pilot Project," takeCHARGE. https://takechargenl.ca/evs/electric-vehicle-load-management-pilot-program/

5.2.7.2 Future ECDM Programming

In 2023, the NL Utilities contracted Posterity to undertake a new CDM Potential Study to assess the technical, economic, and achievable potential for ECDM activities on the Island Interconnected System from 2025 to 2040. The new ECDM Potential Study will conclude in 2024 and will be used by the NL Utilities to develop the next multi-year ECDM plan.

Certain jurisdictions utilize electricity rate structures to influence consumer behaviour and mitigate system demand. The effectiveness of dynamic rate programs is highly dependent on the shape of the load profile on the system. To date, these programs have not represented cost-effective, technically viable options to manage system demand[99] when compared to lower-cost alternatives in Hydro's supply stack.

Like other ECDM initiatives, programs such as TOU Rates and CPP require investment, such as the implementation of smart meters to enable real-time monitoring of electricity usage and administrative costs. In its most recent study,[100] Dunsky cited that the timeline for cost-effectiveness was within the 2024 Resource Plan study period. The new ECDM Potential Study will include an update on this analysis. Once smart metering technology is demonstrated to be least cost for customers, Hydro anticipates incorporating this technology as soon as feasible to enable future dynamic rate structures.

5.3 Transmission

The transmission system plays a crucial role in Newfoundland and Labrador's electricity infrastructure. Due to the geography of the province and the location of electrical customers, significant challenges arise when transferring power from remote generating stations to urban load centers. While over half of the peak demand is concentrated on the Avalon, most hydroelectric resources are located in central

---

[99] As per "Newfoundland and Labrador Conservation Potential Study (2020–2034)," Dunsky, filed as "Application for Approvals Required to Execute Programming Identified in the Electrification, Conservation and Demand Management Plan 2021–2025," Newfoundland and Labrador Hydro, rev. July 8, 2021 (originally filed June 16, 2021), sch. 3, sch. C, the Dunsky Study shows that dynamic rates are not expected to become cost effective until the 2030s.
http://www.pub.nl.ca/applications/2021/NLH2021Capital/NLH2021Capital_SUPP_ExecuteProgram/apps/From%20NLH%20-%20Approvals%20Required%20to%20Execute%20Programming%20Identified%20in%20the%20Electrification%20Conservation%20and%20Demand%20Management%20Plan%202021-2025%20-%20REVISION%201%20-%202021-07-08.PDF

[100] "Newfoundland and Labrador Conservation Potential Study (2020–2034)," Dunsky, filed as "Application for Approvals Required to Execute Programming Identified in the Electrification, Conservation and Demand Management Plan 2021–2025," Newfoundland and Labrador Hydro, rev. July 8, 2021 (originally filed June 16, 2021), sch. 3, sch. C.
http://www.pub.nl.ca/applications/2021/NLH2021Capital/NLH2021Capital_SUPP_ExecuteProgram/apps/From%20NLH%20-%20Approvals%20Required%20to%20Execute%20Programming%20Identified%20in%20the%20Electrification%20Conservation%20and%20Demand%20Management%20Plan%202021-2025%20-%20REVISION%201%20-%202021-07-08.PDF

areas, often hundreds of kilometres away. This disparity necessitates a robust and well-designed transmission system to ensure that generated power demand is efficiently delivered to all customers and meets a level of quality pre-defined by the utility's planning criteria.

5.3.1 Identifying and Addressing Bottlenecks

In 2023, Hydro engaged TransGrid to complete a study[101] to determine the Bay d'Espoir to Soldiers Pond transmission constraints in contingency scenarios. Hydro has identified potential bottlenecks in the transmission system between Bay d'Espoir and Soldiers Pond that could impede the flow of electricity from new generating sources to the Avalon during a LIL bipole outage. To understand and address these constraints, Hydro engaged engineering consultants who have explored various solutions. These options range from constructing new transmission lines to potentially more cost-effective approaches involving the implementation of RAS to quickly respond to system events to avoid exceeding transmission line transfer limits while minimizing customer impact.

As with supply additions, Hydro will pursue a Minimum Investment Required approach with its transmission system, as discussed in Section 7.3.3 of Appendix C. A detailed analysis has confirmed that requirements for new transmission infrastructure can be minimized by strategically installing new generation on the Avalon to the extent practical. Further, Hydro has already undertaken actions to adopt new technologies that may also serve to maximize the capacity of existing infrastructure and minimize costs for customers. Examples of this are discussed in Section 5.3.1.1.

5.3.1.1 Innovative Technologies and RAS[102]

One innovative technology under consideration is DLR, which allows for the optimized operation of transmission lines based on real-time environmental conditions as opposed to hard-coded environmental assumptions—such as ambient air temperature, which can be unnecessarily restrictive. DLR can potentially increase the capacity of existing lines without the need for comparatively costly physical upgrades.

In 2023, Hydro initiated a DLR Pilot Project on TL201, a critical line connecting the Avalon with the rest of the province. This pilot project is designed to evaluate the effectiveness of DLR in enhancing the capacity of transmission lines, which could help avoid or defer significant capital upgrades. The findings

[101] "Avalon Supply (Transmission) Study – Overview," Newfoundland and Labrador Hydro, October 31, 2023.
[102] In industry, RAS is sometimes referred to as Special Protection Scheme.

from this pilot project will be crucial in determining the viability of implementing these technologies more broadly across the network, specifically between Bay d'Espoir and Soldiers Pond.

In addition to DLR, Hydro is also investigating RAS for the Bay d'Espoir to Soldiers Pond transmission system to allow for higher power flows between Bay d'Espoir and Soldiers Pond while reducing the likelihood of transmission line overloads and abnormal voltage conditions. By implementing RAS, Hydro can effectively serve more customer loads on the Avalon during peak times, mitigate bottlenecks when the LIL is unavailable, and potentially eliminate the need for extensive physical upgrades.

Further research is needed to gain a comprehensive understanding of the available solutions for alleviating transmission constraints and the role new technologies and RAS can play. Over the upcoming months and years, Hydro will continue to assess the transmission system and plan necessary upgrades to ensure it meets future requirements. As these plans develop and the full scope of generation supply requirements and associated transmission investments becomes clearer, Hydro anticipates that transmission applications for regulatory approval will be necessary within the next few years.

5.4 Expansion Plans Analysis Outcome

Taking into consideration the system demand requirements and reliability criteria assumptions for each scenario, Hydro identified the incremental capacity and energy requirements to serve its customers. Table 3 presents the results of this analysis and reflects the requirements of the system by 2034.

Table 3: Capacity and Energy Requirements by Scenario

Scenario	Required Reserve Margin[103] (MW)	Incremental Firm Capacity Required[104] (MW, 2034)	Incremental Firm Energy Requirements (TWh, 2034 vs 2024)
1: Reference Case	500	524	1.8
2: Higher Growth than Reference Case	500	668	2.5
3: Slower Growth than Reference Case	500	452	1.4
4: Minimum Investment Required	**360**	**384**	**1.4**
5: Maximum Investment Required	550	768	2.5
6: Increased Electrification	360	518	2.5
7: Improved Reliability	635	602	1.4
8: LIL as an Energy-Only Line	675	757	1.8

[103] Calculated in the reference year 2032.
[104] Assuming the retirement of the Holyrood TGS and the Hardwoods and Stephenville GTs.

6.0 Hydro's Expansion Recommendation

As a result of the Expansion Plan analysis, Hydro is progressing with the Minimum Investment Required (Scenario 4), which is strategically aligned with its mandate to provide safe, reliable electricity in an environmentally responsible manner at the lowest possible cost.

The options required to satisfy system requirements under Scenario 4 are considered the Minimum Investment Required*,* as they represent supply additions that are required under all scenarios. These options include:

- Construction of a new 154 MW hydroelectric unit (Unit 8) in Bay d'Espoir;
- Construction of a new 150 MW CT resource with renewable fuel capabilities on the Avalon;[105] and
- Integration of 400 MW installed capacity of wind generation.

By focusing on these foundational supply options, Hydro addresses the immediate need for additional resources to meet the growing demand for electricity in Newfoundland and Labrador. However, additional resources and further actions would be necessary in all other scenarios to accommodate the evolving energy landscape.

It is important to note that for other scenarios analyzed, such as increased decarbonization activities, the first resources required in those plans are the same as the Minimum Investment Required. Therefore, by proceeding on the basis of the Minimum Investment Required scenario, Hydro is also advancing the first steps of the Reference Case Expansion Plan.

Although the scope of this energy transition continues to be evaluated, one constant remains—additional investment in the electricity system is required to ensure adequate supply in any expansion plan considered.

[105] While Hydro has assumed 150 MW of CT capacity based on the ability to fuel a CT of this size, the nominal plant rating may marginally differ depending on CT procurement.

At present, there are alternatives to satisfy the incremental load growth between the Minimum Investment Required and the Reference Case. Hydro is taking the appropriate actions to be ready to expedite additional supply should the expected case materialize.

Throughout each project's planning process, Hydro, in collaboration with relevant parties, will make incremental decisions at crucial milestones to ensure that every phase of project development is well-informed and resources are committed prudently.

As discussed in the following sections, Hydro has conducted extensive analyses of various potential outcomes, collaborated with relevant parties on phased decision-making and initiated FEED and EAs on resource additions common to all scenarios. These steps are designed to expedite the integration of new resources, facilitate the retirement of aging thermal generation, and ensure continued long-term system reliability.

6.1 Hydro's Plan: Minimum Investment Required

The electricity landscape is in transition, as efforts focus on reducing the reliance on carbon-emitting energy sources and increasing the use of electricity to power the economy and daily life. The evolving needs of the electrical system will become clearer over time. As new policies and programs take effect, customer behaviours change and the potential of new technologies becomes apparent. In the Minimum Investment Required scenario, a minimum of approximately 385 MW of capacity and 1.4 TWh of energy is required to serve customers on the Island Interconnected System by 2034.

While further supply resources are required to meet the Reference Case when compared to the Minimum Investment Required scenario, it is prudent to take action today to ensure resources that are required under all scenarios are brought online as soon as possible.

Hydro has begun planning and designing three key supply options, which will enable the retirement of Holyrood and meet supply requirements for the next decade. These options reflect the Minimum Investment Required under all scenarios regardless of the reliability criteria and pace of load growth:

- Construction of a new 154 MW hydroelectric unit (Unit 8) in Bay d'Espoir;

- Construction of a new 150 MW CT resource with renewable fuel capabilities on the Avalon;[106] and
- Integration of 400 MW installed capacity of wind generation.

These options represent the Minimum Investment Required; however, they are insufficient to meet the anticipated demand (Reference Case) and reliability criteria. Hydro has begun to mitigate the risk of supply shortage by advancing the second capacity option as part of its recommendation, which has a material benefit to the reliability of the Island Interconnected System in the event of a prolonged LIL bipole outage and is beneficial to ensure the retirement of aging thermal assets as planned. Lastly, if the Reference Case load forecast was to increase and/or the LIL bipole EqFOR is higher than 1%, both capacity options are required.

The three supply solutions included within the Minimum Investment Required scenario are consistently shown to be the least-cost solutions across a broad range of sensitivities. Further, transmission constraints demonstrate the need for generation on the Avalon to avoid cost-prohibitive transmission upgrades. Finally, fuel supply risks are such that future supply cannot solely be provided by CTs and that other least-cost capacity options, (specifically and immediately Bay d'Espoir Unit 8 as a best option) must be explored.

The planning, construction, and integration of new generating resources can take up to a decade depending on review processes and evolving supply chain scenarios, underscoring the need for immediate action to address increasing demands on the electrical system.

Immediate decisions are necessary to advance the planning, construction, and integration of these new supply resources based on current understanding, while also planning for future adjustments to accommodate a shift to a greener economy. As such, Hydro plans to issue an expression of interest for energy provision in 2025 and is currently proceeding with the planning and engineering of the selected

[106] While Hydro has assumed 150 MW of CT capacity based on the ability to fuel a CT of this size, the nominal plant rating may marginally differ depending on CT procurement.

additions to its resource supply—a new unit in Bay d'Espoir and a 150 MW CT addition on the Avalon as discussed further in Section 7.0.

6.2 Meeting Reference Case Requirements

Navigating the complexities of transitioning to a sustainable energy future has made it increasingly clear that additional supply resources above and beyond those Hydro is currently progressing will likely be necessary to meet the growing demands of the electrical system. However, before making informed decisions regarding these next required resources, a further analysis is essential with feedback from parties necessary. This analysis will not only help to understand the full scope of future needs but also ensure that investments are both prudent and effective.

Building for the Minimum Investment Required scenario will serve as the foundation to meet the Reference Case, should higher load growth scenarios materialize. Following applications to the Board for the Minimum Investment Required scenario, Hydro will update its resource planning analysis to undertake the analysis necessary for the Reference Case. The focus will be given to ECDM and the integration of new supply options (such as BESS) on the Island Interconnected System, as they are currently showing as the next promising solutions beyond the current recommended solutions.

By studying patterns in electricity usage and forecasting future trends, ECDM can provide valuable insights that will shape the needs of the system and into strategic planning, and inform the role that Hydro's customers, including Newfoundland Power, may play in meeting the future needs of the system and minimizing the investment required. Simultaneously, the integration of renewable energy sources and energy storage solutions has the potential to alter energy infrastructure, offering more resilient and less carbon-intensive solutions. Hydro will continue to explore these new technologies to understand their potential role in the system with the aim of recommending them when the analysis demonstrates it is appropriate.

Further, Hydro's engagement of third parties will help identify and understand additional capacity solutions that could readily be advanced, as needed. For example, the proponents that respond to Hydro's expression of interest for energy will provide an understanding of options and development timelines. Further, ongoing discussions with Newfoundland Power regarding regional CTs may lead to effective Off-Avalon capacity solutions. Meanwhile, Hydro will continue to advance other capacity and energy solutions, including battery storage and uprating the units at existing hydroelectric facilities.

This next analysis will lay the groundwork for future decision-making, ensuring that any additional supply resources are aligned with Hydro's long-term goals for a reliable, affordable, and environmentally responsible electricity system. Through careful planning and engagement with advancements in electricity supply, Hydro aims to fortify its energy strategy and sustainably meet the needs of Newfoundland and Labrador.

6.2.1 Alternative Technologies

As Hydro optimizes and expands the electrical system to meet future demand, understanding and evaluating alternative technologies, such as those that are relatively new on the market or those that have been established but not deployed in Newfoundland and Labrador, is critical. These technologies not only promise enhanced energy storage and generation options but also align with Hydro's sustainability and reliability goals.[107] Particular areas for further study include:

- BESS technologies;
- Renewable fuels for CTs;
- Pumped storage developments; and
- Uprating of existing assets.

6.2.1.1 BESS Technologies

BESS is likely to play a role on Hydro's system in the future as technology advancement helps to reduce the cost; however, further study is required to determine the role, sizing, and location of BESS on the system. This will involve further study to determine the ELCC of BESS on the system, particularly as the load profile and asset mix become clearer.

Current four-hour battery storage technologies, primarily based on lithium-ion batteries, have the potential to improve load levelling, frequency regulation, and peak shaving. However, as the costs of battery technologies continue to decrease, their feasibility and integration into the grid merit ongoing evaluation.

Emerging longer-duration storage solutions like iron-air and flow batteries show promise for extended energy storage capabilities—potentially storing energy for days. These technologies have the potential

[107] "We Are Hydro: Strategic Plan 2023–2025," Newfoundland and Labrador Hydro, December 12, 2023. https://nlhydro.com/wp-content/uploads/2023/12/NEW-strategic-plan-FINAL-DEC-12-WEB.pdf

to significantly enhance the capability of BESS for longer durations and improve the cost-effectiveness and suitability of BESS in light of system needs. Further studies will assess the integration of these innovative storage options with existing infrastructure and as well as the economic benefits and operational viability.

6.2.1.2 Renewable Fuels for CTs

Exploring renewable fuels (such as hydrogen) for CTs is critical for reducing carbon emissions and enhancing the sustainability of energy sources. For example, hydrogen can be generated using surplus renewable energy and stored for power generation, offering a clean alternative to fossil fuels. Studies into the adaptation of current CT technologies to utilize renewable fuels, the infrastructure required for large-scale renewable fuel production and storage, and the overall economic implications are essential. This includes detailed considerations of the technical viability, safety, storage, and transportation logistics of renewable fuels, including hydrogen.

6.2.1.3 Pumped Storage Developments

Pumped storage hydroelectricity is considered one of the most efficient methods for large-scale energy storage and is expanding in use in other jurisdictions. In 2023, Hydro studied the potential of pumped storage at its existing hydroelectric sites; the evaluation of the potential for new pumped storage projects has begun, which could significantly enhance energy management capabilities.[108] Hydro will continue to evaluate pumped storage as a supply option to meet the growing demand on the system, including its role in harnessing the potential of intermittent renewable energy sources, such as wind and solar generation.

The continued research and evaluation of these technologies are vital in effectively planning the system to meet future demand. Moving forward, and in addition to studies Hydro has recently completed, comprehensive studies will explore the technical performance, cost-efficiency, environmental impact, and integration challenges of these technologies and better consider these solutions for the supply stack. Understanding these aspects will ensure that Hydro can make informed decisions to support sustainable growth, enhance grid reliability, and efficiently meet future energy demands.

[108] "Pumped Storage at Existing Hydro Sites – Overview," Newfoundland and Labrador Hydro, October 31, 2023.

6.2.1.4 Uprating Existing Assets

Many of Hydro's hydroelectric generating assets were designed and installed over 50 years ago. Since that time, developments in engineering and technology have led to improved turbine design, which may present an opportunity to increase the generating capacity of existing assets. Through the use of modern engineering techniques and technologies, it may be possible to design modifications to existing assets to increase their capacity. Upgrades of this nature may introduce trade-offs, such as reducing unit efficiency while increasing capacity; therefore, it is important to understand these trade-offs and their impacts when considering unit uprating.

Hydro engaged a third party to study the potential to uprate Bay d'Espoir Unit 7. The study found that there is potential to increase the generating capacity of this unit; however, the consultant also found that the benefits of unit upgrading might also be achieved through the design of the future Bay d'Espoir Unit 8. Therefore, Hydro is considering the findings of this study as it plans for the addition of Bay d'Espoir Unit 8. A summary of the results of the Bay d'Espoir Unit 7 Uprate Study is provided as Attachment 2 to Appendix C.

Further study is required to understand the opportunities and trade-offs for uprating other units on Hydro's system. Future studies will take a holistic approach, understanding the system-level impacts of unit uprating, such as the impacts on system hydrology.

7.0 Next Steps

To meet growing demand, decisions must be made now to ensure Newfoundland and Labrador has adequate supply. Action must be taken immediately based on the best available information; otherwise, the safety and reliability of the electrical grid is at risk. With its Minimum Investment Required strategy, Hydro has a plan to ensure it is prepared to lead the province at this critical point in the global energy transition.

While investment is necessary to provide a clean, safe, and reliable electrical system, this investment can also have substantial socioeconomic impacts on Hydro, the province, and customers. Recognizing that significant investments can bring substantial risks and opportunities, effective and transparent governance and oversight of such projects is critical.

Hydro is utilizing lessons learned from past projects as well as reviewing industry standards, project oversight, and governance practices in other jurisdictions to ensure any large future investment by Hydro appropriately follows good utility practice.

7.1 Building Capability and Capacity

Although not Mega Projects like the Muskrat Falls Project, Major Projects, such as building an eighth unit in Bay d'Espoir, require significant investment and have unique requirements that differ from normal operations within Hydro. This was reflected in Commissioner Richard LeBlanc's recommendation from the *Muskrat Falls Inquiry* for well-defined oversight for projects with a budget of $50 million or more.[109] In response to these unique requirements, Hydro has created a Major Projects Department to:

- **Establish a Framework to Ensure the Successful Delivery of Major Projects:** Prepare Hydro for the regulatory oversight, governance, planning, and execution of Major Projects by developing the right processes, assembling a competent team, and engaging relevant parties to manage risk and maximize value.
- **Manage Individual Major Projects:** Completing Major Projects within cost, schedule, and quality targets.

Like utilities across the globe, Hydro is currently facing unique challenges as it plans the electricity system to enable government policies and changes in consumer behaviour that are driving increased electrification and load growth. Through its newly established Major Projects Department and supporting teams, Hydro will need to manage a portfolio of large projects while meeting both regulatory and public procurement requirements.

Having recently completed a Major Project—the construction of TL267—as well as the Muskrat Falls Mega Project, there are resources and processes that Hydro can use as well as many lessons learned from which Hydro and its customers would benefit. The Major Projects Department recognizes organizational readiness, proper governance, and decision-making are critical to successfully achieving a net-zero electricity grid.

[109] Honourable Richard D. LeBlanc, "Muskrat Falls: A Misguided Project," *Commission of Inquiry Respecting the Muskrat Falls Project*, March 5, 2020, vol. 1, Key Recommendations, p. 61.
https://www.muskratfallsinquiry.ca/files/Volume-1-Executive-Summary-Key-Findings-and-Recommendations-FINAL.pdf

The Major Projects Department has already taken the following actions to ensure the successful delivery of Major Projects:

- Engaged external expertise to support the development of key governance documents for Major Projects to ensure that project decisions are well-founded and well-documented. This included a review of the management of Major Projects within the electrical utility industry in Canada;
- Engaged Hydro's Internal Audit Department to create an audit plan for ongoing review of Hydro's Major Projects and processes;
- Implemented recommended actions as a result of engagement with Hydro's Internal Audit Department to review current governance of Major Projects against industry practices, such as the PMBOK Guide[110] and AACE Recommended Practices;
- Implemented recommended actions as a result of engagement with Hydro's Internal Audit Department to review early cost and schedule estimates of potential projects;
- Established an internal Executive Steering Committee and Special Board of Directors Sub-Committee specific to Major Projects initiatives;
- Developed a lessons-learned database, incorporating recommendations from the *Muskrat Falls Inquiry* as well as lessons learned from past Major Projects;
- Implemented Duty to Document processes in line with proposed amendments to the *Management of Information Act;*[111,112] and
- Initiated early engagement with major suppliers, contractors, and other utilities to understand supply issue challenges and the strategies other utilities are using to mitigate these risks.

[110] Project Management Institute, Inc. *A Guide to the Project Management Body of Knowledge (PMBOK Guide) and the Standard for Project Management,* 7th ed., Project Management Institute, Inc., Newton Square, PA, 2021.
[111] *Management of Information Act*, SNL 2005, c M-1.01.
[112] Amendments proposed under Bill 22, *An Act to amend the Management of Information Act and the House of Assembly Accountability, Integrity and Administration Act,* 2nd Session, 50th General Assembly, Newfoundland and Labrador. https://www.assembly.nl.ca/housebusiness/bills/ga50session2/bill2322.htm

The Major Projects Department has already taken the following actions to progress the new generation projects:

- Ongoing Front-End Planning, FEED, and EA activities for the Bay d'Espoir Unit 8 project, including field studies and stakeholder engagement;
- Ongoing Front-End Planning, FEED, and EA activities for the Avalon CT project, including field studies and stakeholder engagement; and
- Exploring opportunities for ECI for both the Bay d'Espoir Unit 8 and Avalon CT projects.

Initial planning is in motion, with the goal of integrating these resources swiftly. Major Projects initiatives are a corporate priority for Hydro; key deliverables have been identified per department and resources have been assigned, where required, to ensure Hydro is ready to effectively examine and present proposed investments to external relevant parties through the regulatory process and manage any approved major investment in the electrical system.

7.2 Major Projects Life Cycle

The project life cycle represents a series of stages a project passes through, from initiation to closure. Each phase represents distinct goals or milestones in the larger project life cycle. As a project moves through its life cycle, it becomes more defined; increasing levels of project definition and design development allow for more informed cost estimation, schedule development, and risk identification. Phases can overlap for different components of a project and deliverables mature as the project proceeds through the life cycle.

There are many ways to name and organize these stages construction projects typically progress through planning, execution, and closure phases. Figure 7 illustrates an example of the life cycle of a project with associated phases.

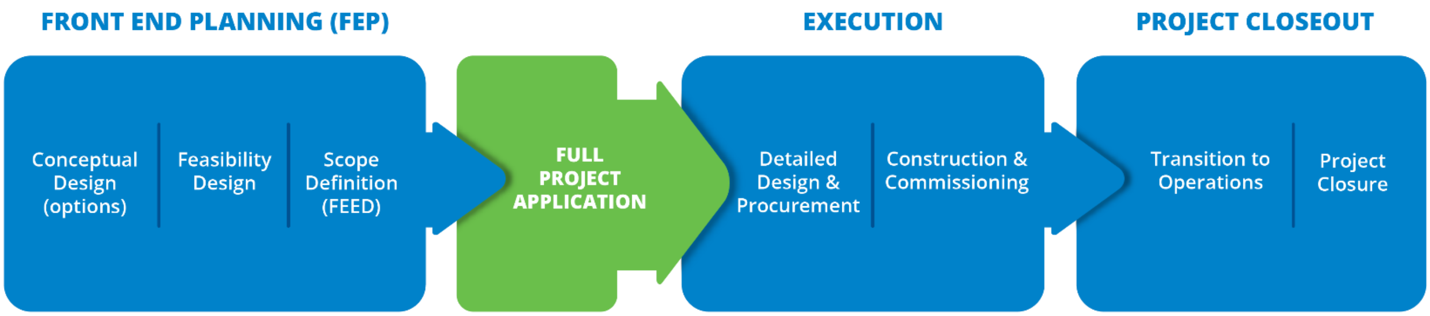


Figure 7: Project Life Cycle

A staged project life cycle approach to project delivery defines points during the life of a project when management carefully considers key information—such as project costs, schedule, scope, and risk—and assesses whether to approve proceeding to the next stage or whether to pause or terminate the project, if necessary. Hydro's current capital projects follow a similar process, with a FEED stage supporting the capital budget application followed by the execution and closeout phases for projects that proceed.

Hydro is currently reviewing processes from other Canadian utilities to develop a formal phased life cycle approach that is typical of large construction projects. The application of well-defined checkpoints, especially early in the project life cycle, provides management and relevant parties with an informed assessment of progress and issues, a validation of the project justification, and ultimately leads to better decisions on plans and investments for the future. This approach is a powerful and appropriate way to formalize project oversight.

Hydro is working with internal stakeholders to develop a draft life cycle process and is planning engagement with relevant external parties to align on the process, including key decision points and criteria for approval. Hydro's key considerations for this process are:

- External engagement, to allow informed, transparent, and efficient decision-making;
- Clearly defined criteria (cost, schedule, and project specifications) and review process for project approval;
- Consideration of decision points during the execution stage, where a commitment to build can be made or reviewed using updated cost estimates based on tender information received for major contracts; and

- Sound change management processes and decision-making during project execution, where project performance metrics, such as cost and schedule, are reviewed and communicated with relevant parties to ensure projects stay within determined risk profiles.

7.3 Current New Build Projects

Hydro's extensive and independently verified analysis has identified the immediate need for resource additions. For capacity, Hydro has identified two major build projects as the preferred solutions to meet the future needs of the Island Interconnected System—a new hydroelectric unit in Bay d'Espoir and a new CT on the Avalon. There is an immediate need to advance these projects and Hydro is making its best efforts to expedite their development while ensuring necessary, rigorous oversight.

The 2023 and 2024 federal budgets highlighted clean electricity Investment Tax Credits for eligible investment in technologies that are required for the generation and storage of clean electricity and its transmission between provinces and territories, which is available to taxable and tax-exempt entities.[113] Hydro is participating in feedback to the federal government through its EC relationship and is monitoring the rules and regulations that are being developed. These Investment Tax Credits could provide significant positive benefits to the cost of construction of Bay d'Espoir Unit 8.

7.3.1 Completion of Front-End Planning

Front-End Planning is critical to the success of a project, as the ability to influence the characteristics of the project is highest at the beginning. From a cost perspective, the lowest costs associated with development and changes occur early in the project life cycle. As such, it is important that Hydro undertake the necessary Front-End Planning.

[113] "Minister Guilbeault highlights the big five new Clean Investment Tax Credits in Budget 2023 to support sustainable made-in-Canada clean economy," Government of Canada, April 5, 2023. https://www.canada.ca/en/environment-climate-change/news/2023/04/minister-guilbeault-highlights-the-big-five-new-clean-investment-tax-credits-in-budget-2023-to-support-sustainable-made-in-canada-clean-economy.html

> ***". . . well performed Front-End Planning can reduce costs, lead to less project variability in terms of cost, schedule and operating characteristics, and increase the chance of meeting a project's environmental and social goals."[114]***
>
> **CONSTRUCTION INDUSTRY INSTITUTE**

Within the context of the project life cycle, the Expansion Plan analysis outlined in Sections 5.0 and 6.0 represents the conceptual design and options analysis that occurs early in the Front-End Planning phase of a project. While remaining Front-End Planning work would typically commence following the filing of the Expansion Plan results, time is of the essence to integrate new supply on the electrical system. Therefore, Hydro is currently executing FEED on both preferred new generation projects. This early decision to proceed was based on the urgent need for capacity solutions identified in the 2022 Update, which identified these supply solutions as the least-cost options for new capacity, further validated in the analysis provided herein.

The work currently underway during the Front-End Planning phase follows industry standards, such as the PMBOK Guide and the AACE Recommended Practices. The outputs from this phase will include:

- Key execution planning documents, including the contracting plan, project execution plan, project controls plan, risk management plan, and other plans and strategy documents that will set a project up for execution success;
- Engineering deliverables that reflect the level of project definition necessary for an AACE Class 3 estimate;[115]
- A cost estimate that meets the required industry standard,[116] the details of which will then be contained in a Basis of Estimate document;
- A cost estimate and contingency analysis that includes consideration for strategic and tactical risks, as well as escalation that includes the effects of inflation plus market conditions. The

[114] "Support for Pre-Project Planning (Best Practice): RT-213 Topic Summary," Construction Industry Institute, 2004–2006. https://www.staging.construction-institute.org/resources/knowledgebase/knowledge-areas/project-planning/topics/rt-213
[115] AACE Class 3 estimate criteria as defined in the appropriate AACE International Recommended Practice.
[116] For example, the cost estimate for the Bay d'Espoir Unit 8 Project will have a Class 3 cost estimate as defined per "AACE International Recommended Practice 69R-12: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industries," The Association for the Advancement of Cost Engineering, August 7, 2020. (AACE 69R-12).

project budget put forward for approval will have a probability value of not less than P85,[117] which is consistent with the recommendation from Justice Leblanc from the *Muskrat Falls Inquiry*.[118]

- The new cost estimates will be reviewed against the Expansion Plan analysis to confirm that the projects remain the least-cost options for ratepayers.
- The establishment of EA registration requirements early in the Front-End Planning stage will reduce uncertainty around cost and schedule impacts associated with the EA process.

These outputs will inform the evidence provided with a build applications submitted to the Board for approval.[119]

7.4 Major Projects Challenges

As stated previously, all Major Projects come with risks and opportunities for an organization. It is critical to understand these and factor them into the cost and schedule estimate. The sections that follow will touch on some of the challenges facing Hydro today.

7.4.1 Supply Chain Challenges

Multiple events, including the COVID-19 pandemic and geopolitical tensions, have caused significant, ongoing disruption to supply chains across the globe. Many industries have experienced material unavailability, project delays, inflated costs, and labour shortages. This, along with increased market demand associated with North America's aging utility infrastructure and need for new energy sources, has resulted in a significant change in procurement strategies for Major Projects.

Lead times for major equipment, such as transformers, have tripled in recent years, which have significantly impacted project schedules and, considering recent inflation, project costs. Supply chain challenges have heavily impacted the construction industry and contractors involved in Major Projects are no longer willing to accept the contract risk they once did.

---

[117] A P85 estimate is an estimate that incorporates sufficient contingency allowances such that there is an 85% likelihood that the cost estimate will not be exceeded.
[118] Honourable Richard D. LeBlanc, "Muskrat Falls: A Misguided Project," *Commission of Inquiry Respecting the Muskrat Falls Project*, March 5, 2020, vol. 1, Key Recommendations, p. 61. https://www.muskratfallsinquiry.ca/files/Volume-1-Executive-Summary-Key-Findings-and-Recommendations-FINAL.pdf
[119] Hydro intends to file applications for approval of construction of additional generation in late 2024 or early 2025.

> ***"We have seen contractors refuse to bid if the project delivery model is, in their opinion, inappropriate to the circumstances, and we have seen prices that are very high to account for what is considered to be inappropriate risk allocation."[120]***
>
> **RYAN CHALMERS, AIRD & BERLIS**

The push to decarbonize electricity grids across Canada has increased the number of planned projects all competing for the same contractors and suppliers. This abundance of work has created an environment where contractors and suppliers can be selective on what they bid. Project owners have been successful in attracting competent contractors at competitive prices by utilizing contracting strategies where risk is appropriately allocated between parties, which avoids burdening contractors with risks beyond their control. Informal feedback from both utilities and contractors has consistently noted that owners, in response to the current market trends, have evolved their contracting strategies to avoid assigning uncontrollable risks to contractors. Further, commercial strategies that attempt to align owner and contractor risks and rewards, such as target price contracting, have increased in popularity. In response to this feedback, Hydro has been working closely with external advisors to prepare an overarching contracting strategy to assess and validate these new market trends and to determine how they can be employed to support the successful execution of Major Projects. This emphasizes the requirement for a clear understanding of risk through effective FEED work.

Major equipment suppliers and large construction contractors are no longer willing to spend time on preparing budgetary pricing and the timeframe for expiry of quotations and tender pricing has decreased significantly. This has created challenges in estimating accurate pricing and delivery times for project planning. This, along with high inflation, has resulted in project cost estimates going "stale" very quickly.

[120] Ryan Chalmers, "Construction Law: Balance of Risk Takes Centre Stage as Canada Emerges from COVID-19," Lexpert, December 18, 2023. https://www.lexpert.ca/legal-insights/construction-law-balance-of-risk-takes-centre-stage-as-canada-emerges-from-covid-19/382243

> ***"The failure to allow greater risk-taking and innovation by electricity companies to adapt to these changing conditions would be a hindrance not only to industry's progress and modernization, but also detrimental to customers in terms of the rates they pay, how services are delivered, and the energy management options they have."[121]***
>
> **ELECTRICITY CANADA**

Many utilities are now exploring new procurement strategies to mitigate these risks, including ECI and strategic supplier partnerships. Directly involving the contractor early leverages industry expertise to jointly identify risks, establish risk allocation/treatment plans, confirm pricing structures, and improve project cost estimates and schedules through detailed construction planning, including construction methodology, logistics, and other considerations.

Hydro has met with several contractors, suppliers, and utilities to further understand this new environment. Hydro has also engaged external expertise to develop a commercial strategy for Major Projects that include these or similar strategies.

7.4.2 Approval Timeline Challenges

Approval timelines, both internal and external, can create challenges for Major Projects. As discussed previously, cost estimates can change rapidly and significantly when major equipment and construction contract pricing do not have a long shelf life, as is seen in today's market. Utilities across Canada are seeing direct cost increases as a result of delays in approval and permitting of projects—recently estimated a net direct cost of more than $500 million over the past five years.[122]

> ***Significant delays while awaiting approval for a Major Project can increase the risk of losing key resources. Furthermore, given current inflation levels, any timeline increase in project schedules can significantly increase overall project cost. Conversely, any efforts to improve project schedules can result in significant cost savings.***

[121] "Economic Regulatory System," Electricity Canada.
https://www.electricity.ca/knowledge-centre/the-grid/regulatory/economic-regulatory-system/

[122] Joel Forrest (Director, Regulatory Facilities in Canadian Natural Gas Pipelines for TC Energy), "Regulatory Efficiency: Initiatives that make a difference" presentation at the 2024 CAMPUT Conference – From Talk to Action: Solutions to Energize our Future, Calgary, May 7, 2024.

For Hydro, in addition to project cost savings, there is the potential for cost savings associated with the continued operation of the Holyrood TGS. Hydro is committed to working with all relevant parties to developing collaborative mechanisms to expedite approval timelines while ensuring that the required rigor of review processes remains intact.

7.4.3 Resource Challenges

To meet the needs of Canada's goal of net zero by 2050, electrical systems across the country are expanding. At the same time, Canada's aging workforce is seeing a high number of retirements and the labour market is highly competitive.[123] Workforce planning and industry-competitive compensation will be critical to the success of any Major Project. According to EHRC, employment in Atlantic Canada's electricity sector is anticipated to grow by nearly 2,500 jobs by 2028, due to expansion and retirements. An estimated 1,200 of those jobs will be in the engineering, technician, and technologist occupational group.[124] Hydro is experiencing some of these impacts with increased rates of attrition, resignations in engineering and professional roles, and challenges with engaging consultants for technical work, while also working to address compensation-related concerns. To better understand and mitigate these risks, Hydro is completing a Labour Workforce Analysis with BuildForce Canada[125] to gain an increased understanding of labour availability and long-term trends, develop a human resources strategy to support Major Projects, refresh its multi-year organizational integrated workforce plan, and complete an independent third-party compensation review.

7.4.4 Organizational Readiness

For utilities, Major Projects often require multiple years of construction and significant amounts of funding to deliver and complete these projects. Following and ramping down from more than a decade of Mega Project construction/commissioning of complex electrical infrastructure under the Muskrat Falls Project as well as Hydro's transitioning away from a Mega Project Delivery Model, Hydro is now facing a period of ramping up organizationally to tackle large builds. By learning from past successes and

[123] "Majority of people planning to retire would continue working longer if they could reduce their hours and stress," Statistics Canada, August 1, 2023. https://www150.statcan.gc.ca/n1/daily-quotidien/230801/dq230801a-eng.htm

[124] EHRC estimates based on Labour Force Survey, EHRC Model 2023, and "Canada's Energy Future Data Appendices," Canada Energy Regulator, 2016.

[125] Hydro is a Strategic Partner with BuildForce Canada, which is an organization that provides labour market information, tools, and resources to assist with the management of workforce requirements within the construction industry. Other BuildForce Canada Strategic Partners include the Newfoundland and Labrador Construction Association, BC Hydro, Ontario Power Generation, and the National Construction Labour Relations Alliance.

failures, Hydro is assembling an owner's team with the right skills, experience, and processes to ensure adequate planning, governance, and decision-making for these new builds.

7.5 A Collaborative Approach

Hydro is committed to transparency and values full and informed public discussion to plan an electrical system that meets current and future needs. A fulsome regulatory review is expected and welcomed for all Major Projects proposed by Hydro. Given the challenges outlined herein and the complexity required for Major Projects, it would be in the best interest of customers and all parties to optimize the processes required, for internal and external relevant parties, to achieve the appropriate review.

Similar challenges are happening in regulatory environments all across the country. In its 2024 State of the Electricity Industry Report, EC states,

> To achieve any of these goals we will require a huge level of collaboration from all levels of government—Federal, Provincial and Indigenous—as well as regulators. It is imperative that everyone builds consensus on the critical need to address decarbonisation through electrification and to address the targets and timelines.[126]

In the same report, EC also states,

> Provincial governments also need to establish a non-adversarial regulatory system to enhance trust and collaboration among key players with the aim of achieving government policy priorities, societal expectations, and best value for customers.[127]

Engagement with the external parties will be required to determine what process changes could look like but, conceptually, a robust governance process is required to provide:

- The ability to effectively react and adapt to changes (e.g., changes in cost estimates, policy, technology, etc.);
- An effective regulatory approach to ensure advancement through the approval process in a manner that is transparent and complete but does not significantly delay procurement, financing, or project execution; and

[126] "Getting to Yes: The State of the Canadian Electricity Industry 2024," Electricity Canada, March 22, 2024, p. 9. https://issuu.com/canadianelectricityassociation/docs/soti_2024_e
[127] "Getting to Yes: The State of the Canadian Electricity Industry 2024," Electricity Canada, March 22, 2024, p. 15. https://issuu.com/canadianelectricityassociation/docs/soti_2024_e

- Clear expectations regarding the nature of the justification and the evidence threshold required to progress decision points.

Hydro is committed to continued communication and collaboration, sharing of information, and building a shared understanding of the issues, which can be achieved through frequent and continued dialogue by way of informal meetings, information exchanges, workshops, etc. Any feedback received by Hydro through these meetings will improve the quality of the evidence provided, enhance understanding, and allow for efficient review and decision-making. As previously stated, minimizing time on today's projects remains a crucial factor for customer cost savings.

Urgent action is needed and collaboration by all parties is required to succeed at meeting these challenges—the NL Utilities cannot do it alone. The Board, the NL Utilities, policymakers, Indigenous communities, and all relevant parties must work together to ensure electricity grids support the clean energy transition while mitigating the risk of customer outages caused by insufficient supply if the commissioning of new supply solutions is delayed.

8.0 Continued Resource Planning

Utility resource planning is constant. Consistent with good utility practice, Hydro will continue to regularly assess load growth, asset performance, and demand for energy and capacity. As the utility responsible for generating the vast majority of the electricity for the province, it is critical that Hydro is continuously looking ahead. Electricity demand is rapidly growing and this iterative process will result in additional resources in the future to meet various demands, such as the conversion of oil heating and gas-powered vehicles to electric in an effort to reduce carbon emissions.

Following this process, Hydro will continue to make evidence-based decisions on future additional supply sources that are right for the province and customers. The solutions presented in this 2024 Resource Plan reflect the Minimum Investment Required in planning for the future and will result in applications for building additional generation resources to meet increased electricity demand and maintain current reliability. To meet the Reference Case for load growth, Hydro is confident that further action and expansion will be required beyond this 2024 Resource Plan and work is ongoing to determine the next steps and next best alternatives.

As highlighted throughout this report and by EC,[128,129] Hydro expects rapidly changing inputs to system planning as electrification drives demand; therefore, consistent with good utility practice,[130] Hydro continues to recommend updating its Resource Adequacy Plan every other year, with the next update planned for filing in 2026.[131] In the interim, Hydro will continue to perform analysis on the least-cost options to satisfy the Reference Case and continue to monitor load changes and resource capabilities. As the precise trajectory of load growth over the next decade is uncertain and LIL performance is still being proven, Hydro will continue preplanning of additional expansion alternatives, should they be required.

The biennial filings will allow for the development and assessment of supply adequacy under various potential future realities and each update will provide additional information on the analysis conducted throughout the interim years and incorporate revised results. This will enable Hydro to determine appropriate next steps to ensure the security and supply of the system beyond the Minimum Investment Required to address the Reference Case. At present, there are alternatives to satisfy the incremental load growth between the Minimum Investment Required and the Reference Case. Hydro is taking the appropriate actions to be ready to expedite additional supply should the expected case materialize.

9.0 Conclusion

As is true across the globe, it is a time of transition for the Newfoundland and Labrador electricity system, as it faces growing demand without current grid supply. The increasing demand for electricity in Newfoundland and Labrador is primarily driven by provincial economic forecasts, industrial growth demand, and electrification. Hydro has a legislated responsibility to ensure adequate supply and reliable service for the people of the province and is taking the necessary action to mitigate the risk of customer

---

128 "Power and Utility Industry Trends: How can Canada's energy and utility companies prepare for a net-zero future?" PwC Canada. https://www.pwc.com/ca/en/industries/energy/publications/how-can-canadas-energy-and-utility-companies-prepare-for-a-net-zero-future.html

129 "A clean electricity standard in support of a net-zero electricity sector," Environment and Climate Change Canada, March 8, 2022. https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/achieving-net-zero-emissions-electricity-generation-discussion-paper.html

130 Hydro maintains that the filing of the 2024 Resource Plan is the most appropriate opportunity to pivot to a more iterative process akin to an IRP model, such as the five-year frequency of BC Hydro. "2021 Integrated Resource Plan – 2023 Update," BC Hydro and Power Authority, December 21, 2023, sec. 2.4, p. 7. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/integrated-resource-plan-2021.pdf

131 In correspondence dated August 17, 2023, the Board deferred consideration of this proposed change in Hydro's filing requirements for the 2024 Resource Plan to be considered during the ongoing *RRA Study Review*.

outages due to insufficient supply of electricity. As outlined by the 2024 Resource Plan, Hydro has completed an extensive analysis (which has been reviewed by independent third-party consultants), assessed various scenarios and sensitivities, and thoroughly evaluated all options. In every scenario studied, additional investment for generation resources to ensure adequate supply is required.

Hydro has been actively engaging with electricity customers throughout the province, who have expressed great concern about the cost of living, including electricity rates. As a result, Hydro's Expansion Plan reflects the Minimum Investment Required scenario—what Hydro absolutely must do to support reliability and load growth requirements.

As a result of its analysis, Hydro is exploring the integration of wind power to meet future energy needs as well as progressing with FEED on two supply solutions—Bay d'Espoir Unit 8 and a new 150 MW CT resource on the Avalon. Hydro is doing so to ensure there is sufficient evidence to support and justify the required generation expansion; however, any new supply would be seven to ten years away from the date of applications for approval.[132]

There is broad recognition that the magnitude of the energy transition requires a reassessment of policy as well as regulatory and investment planning methodology. If this does not occur in an expedited timeline, net-zero targets will not be met. Further, delays will result in increased costs to customers from increased project and financing costs as well as compounding supply chain issues.

The energy landscape is constantly changing and supply chain pressures continue to increase; therefore, decisions must be made now and immediate action taken to ensure adequate supply to meet growing demand. Continued action must be taken as the system indicates necessary; otherwise, the safety and reliability of the electrical grid and the province's ability to meet net-zero requirements are at risk.

"It's actually time that is the killer for projects, not size . . . By acting fast, you can reduce your risks enormously, especially if you have been thinking slow."[133]

BENT FLYVBJERG

[132] Hydro has assumed a one-year regulatory process in which to obtain approval within this timeline.
[133] "Bent Flyvbjerg "Bent Flyvbjerg's secrets of project success," Association for Project Management, March 20, 2023. https://www.apm.org.uk/blog/bent-flyvbjerg-s-secrets-of-project-success/

Hydro recognizes that technology is rapidly evolving. New technologies, such as energy storage solutions, that can help generate or deliver electricity to customers will continue to become available and cost-efficient over time; however, the urgency required to meet demand growth requires Hydro to make decisions based on what is currently known.

Effective decisions hinge on striking a careful balance between cost, reliability, and environmental considerations. Today's decisions are guided by the best available information but the ongoing requirements for further generation remain clear moving forward.

The decisions to proceed with these projects will not be made by Hydro alone. Hydro is in the process of preparing evidence for applications for the first of these generation additions. The energy landscape is rapidly evolving and so too must the traditional utility planning process. Hydro is committed to engaging with the Board, interested parties, and other regulatory bodies to ensure that such applications are prudent, well-informed, and promote regulatory efficiency to expedite the integration of these resources.

Appendix A

Appendix A

2024 Reliability & Resource Adequacy Process Review

Daymark Energy Advisors

May 9, 2024

DAYMARK ENERGY ADVISORS

MEMORANDUM

TO: Newfoundland & Labrador Hydro

FROM: Daymark Energy Advisors

DATE: May 9, 2024

SUBJECT: 2024 Reliability & Resource Adequacy Process Review

Daymark Energy Advisors, Inc. (Daymark) was retained to support Newfoundland and Labrador Hydro (Hydro) by providing an independent review of its resource planning processes associated with the development of the 2024 Reliability & Resource Adequacy (R&RA) filing. Daymark's support also included providing PLEXOS modeling related to resource expansion. This memorandum provides a high-level overview of the advisory support provided by Daymark to Hydro in support of its resource planning process.

Building on Daymark's work in support of the interim 2022 R&RA filing, Daymark provided an independent review of Hydro's ongoing investigation into how best to meet the reliability and resource adequacy requirements of the provincial electric system considering the additions of the Labrador- Island Link (LIL), the Maritime Link (ML), and the Muskrat Falls Generating Station. Hydro seeks to ensure that it continues to provide acceptable levels of reliability while balancing the overall cost of the system.

As part of this effort, as documented in detail in a separate Daymark report and memos, Daymark has provided Hydro support with specific emphasis on the following key areas.

1. Load Forecasting Process[1] – Daymark reviewed the methodologies and assumptions associated with the development of Hydro's peak and energy forecasts and provided both guidance and considerations for further improvement.

2. Resource Alternative Cost Estimates [2] – Daymark reviewed Hydro developed estimates for consistency with industry norms.

3. Firm Energy Methodology Review [3] – Daymark reviewed Hydro's process for consistency with industry norms and provided modeling support in the development of Hydro's resource expansion plan. Such support included system operational

[1] Daymark report, "Independent Load Forecasting Process Review", dated March 22, 2024
[2] Daymark memo, "Resource Cost Comparison Memo", dated April 1, 2024
[3] Daymark memo, "Energy Analysis Memo", dated May 9, 2024

assumptions, the development of expansion alternatives and planning scenarios or energy futures for evaluation.

Daymark began working with Hydro in Spring 2023 in anticipation of a Fall 2023 R&RA filing. Daymark remained engaged through Q2 2024 and the remaining intervening period.

Daymark's emphasis during this independent review was on providing Hydro and stakeholders with a broad perspective and industry context through this and other memos. The Daymark support took many forms including meetings with the Hydro staff involved in developing the analyses required for the ultimate R&RA, reviews of methodologies, discussion of technical methodologies and data sources, and consideration of policy implications on planning. These efforts are further summarized in the following sections.

LOAD FORECASTING PROCESS

As part of our independent review of the R&RA methodologies, Daymark reviewed the load forecast methodology to assess its reference and alternative futures forecasting methodology and potential load requirements. Daymark also investigated how Hydro addresses the many uncertainties and defines the scenarios to address potential energy need to better inform planning and actions recommended.

In our review, we worked with Hydro to establish a repository of data representing the model construction, underlying data, and reference case results. Given this initial set of information, Daymark was able to review the model philosophy, variable constructions, and any potential confounding variables. Given this review, we suggested sensitivities to Hydro's model that eliminated, transformed, and added variables to account for any erroneous or confounding effects. Finally, with a set of model sensitivities, Daymark evaluated the regression summary statistics, model error, and predictive power, examining how various model constructions impacted the significance of independent variables.

Daymark concludes that Hydro's forecasting is sound and incorporates the ability to analyze multiple potential futures, while addressing the many uncertainties in the industry; Hydro's multiple future options support the evaluation of R&RA as the local economy and industry changes continue to evolve.

Although we conclude that the methodologies used by Hydro are consistent with industry practice, we also recommend Hydro address, in each planning cycle, the continuing need to enhance its ability to incorporate significant industry change into the forecast. It is standard in the industry to make continual modifications to forecasting methodologies to account for a rapidly changing industry such as policy changes to address decarbonization, adoption of additional renewable resources, and adoption of new technologies that drive industrial business increases in the region.

RESOURCE ALTERNATIVE COST ESTIMATES

The cost and production characteristics of expansion plan resources vary significantly based on resource type, site, and more. It is critical that any cost estimates used in this process are comparable to similar resources across the industry. To support expansion planning, Daymark compiled cost estimate benchmarks from multiple sources to compare against Hydro's internal estimates.

Daymark reviewed cost estimate benchmarks provided by the NREL's 2021 Annual Technology Baseline (NREL ATB), the January 2024 Capital Cost and Performance Characteristics report by the U.S. Energy Information Administration and Sargent & Lundy (S&L), and the Alberta Electric System Operator's 2018 Cost of New Entry Analysis (AESO). For conversions from $USD to $CAD, we assumed a rate of 1 USD to 1.357 CAD. Inflation was benchmarked on annual average inflation rates as reported by the U.S. Department of Labor.[4]

Based on Hydro's resource assumptions, Daymark identified comparable technologies in each report to identify appropriate cost benchmarks. These technologies are summarized in Table 1. These technologies are not perfect parallels to the resources selected by Hydro; however, they provide a valuable point of reference in verifying the validity of Hydro's estimates. Given these benchmarks, Daymark commented on whether Hydro's estimate fell within industry standards, were reasonable given site- or technology-specific conditions, or otherwise. In general, we found Hydro's estimates to be reasonable.

[4] See Table 3 in the Appendix for inflation assumptions.

Table 1: Benchmarked Technologies

Category	Hydro	NREL ATB	S&L	AESO
Thermal	GE LM6000 CT, 142 MW	Simply Cycle, 4x Aeroderivative Turbine Arrangement, 211 MW	N/A	GE LM6000-PF SPRTIN, 87 MW
Hydro	Various, 18 MW to 154 MW	Various, 1 MW to 30MW+	100 MW	N/A
Wind	Land-Based Wind, 100 MW	Land-Based Wind, 200 MW	Large Onshore Wind, 200 MW	N/A
Solar	Solar PV, 20 MW	Solar PV Single Axis Tracking, 100 MW	Solar PV, 150MW	N/A
BESS	4-Hour Battery, 20 MW & 50 MW	4-Hour Battery, 60 MW	5-Hour Battery, 160 MW	N/A

FIRM ENERGY ANALYSIS

As part of the review of the Resource Adequacy Study process and methodology, Daymark reviewed NLH's Firm Energy Analysis. The Firm Energy Analysis compares the energy generating capability of the existing fleet under a set of assumptions against the expected load for each year of the 2023-2042 horizon. The analysis also assessed the firm energy that could be relied upon to meet Island load from the Labrador Island Link. Because the flow over the LIL is dependent on Island load, three load scenarios were considered in the analysis.

Key assumptions regarding the generation capability of the system are as follows:

(1) Output from Hydro-owned, Newfoundland Power-owned, Star Lake and Exploits hydraulic generation reflects energy from worst-case historical drought sequence for the "Firm Gen" scenario and average hydrology for the "Average Gen" scenario.

(2) Holyrood TGS's generation reflects partial retirement in Spring 2030 (Units 1 and 2 retired and Unit 3 permanently converted to synchronous condensing mode).

(3) Energy contributions from combustion turbines and diesel units are not considered for either Hydro-owned or Newfoundland Power-owned resources, consistent with previous methodology.

(4) Firm energy contributions from imports over the Maritime Link are not considered.

(5) Delivery of the Nova Scotia Block contractual commitment is considered.

In all scenarios, energy shortfalls are present beginning in 2030, with the retirement of the Holyrood Thermal Generating Station, and continue to increase to the end of the forecast horizon. Overall, Hydro's approach to the analysis is sound. However as the nature of the analysis is deterministic, it presents worst case scenario conditions and results. To draw more general conclusions, a probabilistic analysis would be informative.

The Firm Energy Analysis was conducted separate from the Resource Adequacy PLEXOS model, as a spreadsheet model which then fed inputs into the PLEXOS modelling effort. Because of the usage of the Firm Energy Analysis as an input to the expansion model, Daymark recommends bringing the Firm Energy Analysis into greater alignment with the overall resource planning process using Hydro's PLEXOS model.

RELIABILITY ANALYSIS

In 2018 Daymark was engaged to assist Hydro in a review of alternative industry approaches to resource adequacy. At that time our review identified the 1 day-in-10 years (0.1 days per year) LOLE standard as the most prevalent approach. However, we also noted that while the adoption of the criteria itself prevailed in the industry, the method by which modelling, and determination of supply adequacy was conducted is subjective and varies between utilities.

Utilities, system operators, and regulators across North America have relied on variations of the 1-in-10 standard for many decades, and typically enforce the standard without evaluating its economic implications. For Hydro, the economics of resource adequacy is a critical consideration given the recent investments in Muskrat Falls and the associated transmission infrastructure.

In most U.S. and Canadian power systems, the 0.1 LOLE standard is interpreted to mean that planning reserve margins need to be high enough that involuntary load shedding due to inadequate supply would occur only once in ten years. One event in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events.

Further, the manner in which transmission interconnections, interruptible loads, voltage reductions, and load uncertainty are treated, all add to the potential variability in the level of planning reserve margin required. There is no one-size-fits-all approach to the determination of resource adequacy. The approach taken to developing a planning reserve margin is dependent on the specific circumstances and needs of a given utility. The difference between these interpretations of the 1-in-10 standard and generation planning assumptions can translate to potentially significant differences in required planning reserve margins.

Hydro is currently planning to an LOLH of 2.8. Hydro will continue to assess this potential of adopting 0.1 LOLE in consideration of the balance between cost and reliability as aging thermal assets are retired and new assets are integrated into the Island Interconnected System. .

For the 2024 R&RA assessment, Hydro's key assumptions include the continued operation of Holyrood TGS, Hardwoods GT, and Stephenville GT until 2030 (or until an adequate replacement is in place), treating Muskrat Falls as 700 MW of firm capacity at the bus, delivered to the island with a range of LIL forced outage rates (1%, 5%, and 10%).[5]

To better understand and plan for the resource adequacy implications of varying the key assumptions, Hydro has created several alternative scenarios to test the sensitivity of the resulting reserve margin to varying key assumptions. Specifically, Table 2 shows the scenarios and key assumptions of each.

Table 2: Scenarios and Key Assumptions

Scenario	LIL Capacity	LIL FOR	Island Load	Labrador Load
S1: Reference Case	700 MW	5%	Reference	Reference
S2: Accelerated Island Decarbonization	700 MW	5%	Accelerated Decarbonization	Reference
S3: Slow Island Decarbonization	700 MW	5%	Slow Decarbonization	Reference
S4: Slow Island Decarbonization; Lower LIL DAFOR	700 MW	1%	Slow Decarbonization	Reference
S5: Accelerated Island Decarbonization; Higher LIL DAFOR	700 MW	10%	Accelerated Decarbonization	Reference
S6: Accelerated Island Decarbonization; Lower LIL DAFOR	700 MW	1%	Accelerated Decarbonization	Reference
S7: Slow Island Decarbonization; 0.1 LOLE	700 MW	5%	Accelerated Decarbonization	Reference
S8: Reference Case LIL treated as Energy Only Line		100	Reference	Reference

[5] LIL capacity was modelled at 675 MW in the PLEXOS Model, as shown in **Error! Reference source not found.**. This is 25 MW less than the firm capacity of Muskrat Falls at the bus.

The use of scenario analysis is standard practice in the development resource adequacy assessments.

Beyond this scenario analysis, Hydro has also investigated the implications of the LIL not being available for a six-week period during a peak load winter period. Given the distance, rugged terrain, remoteness as well as overhead and undersea nature of the LIL, and the time required for repair response, we believe it is prudent to assess the implications of not having the LIL for an extended period. In the event of an outage, a six-week repair time was assumed based on studies that were performed by external consulting firms.

CAPACITY EXPANSION MODELING

Daymark was engaged by Hydro to assist with the execution of the PLEXOS modelling for the Resource Adequacy Study. This engagement can be characterized by three key phases: the creation of scenarios for analysis, the creation of the Resource Adequacy model and the execution/iteration of the model.

Daymark received the base Resource Adequacy Study model from Hydro and reviewed the setup of the model to fully understand modelling decisions, identify any underlying assumptions, and ensure that modelling consistent with industry practices were being used. Upon finalizing the review and discussing the results with Hydro, Daymark determined that the model was an accurate representation of the Hydro system in both the present state and forecasted future states. To further confirm this, Daymark executed benchmarking tests for the model.

Parallel to this model review, Daymark assisted Hydro in developing alternate scenarios intended to represent a range of future outcomes. Considering these scenarios as part of the expansion planning process ensures that the lowest cost build option is balanced against potential load growth, electrification, and other changing conditions on the Hydro system. Ultimately, Slow Decarbonization, Reference Case, and Accelerated Decarbonization scenarios were considered, as well as varying levels of reliability for the LIL transmission line. Developing and testing expansion plans over a variety of scenarios is part of standard industry practice for expansion planning.

Finally, the Resource Adequacy Study model was updated with the latest information from Hydro including load, hydro plant restrictions, generator characteristics, transmission system characteristics, as well as the properties of the new build generator options under consideration. After this was completed, the model was executed and Daymark then focused on optimizing model execution parameters within the PLEXOS software to ensure the mathematical solver was operating with sufficient precision to produce a reliable and reproducible solution. Once optimization parameters had been determined, the model was executed across all scenarios and model iteration began to validate model decision making with regards to new builds, build timing, and new build parameters. The model was extensively iterated with continual feedback from the Hydro and Daymark teams, and tested across all scenarios to ensure results that were accurate and reproducible, which is in line with standard industry practice for Resource Expansion planning.

OVERALL PLANNING PROCESS ASSESSMENT

Overall, Hydro's planning process as it relates to assessing resource adequacy is generally consistent with approaches used in the industry. Hydro's assumptions and rationale as they relate to transmission interconnections, interruptible loads, and load forecasting and uncertainty are all documented in the 2024 Resource Plan in support of the RRA filing and are consistent with Hydro's stated goal of providing reasonable reliability at the lowest cost. Reasonable being defined by Hydro as a) consistent with past practice and b) supportive of provincial decarbonization goals.

Future Considerations

Daymark offers the following considerations as Hydro continues to evolve its Resource Planning Process to be more consistent with industry norms.

Load Forecast

To account for growing uncertainty regarding GHG abatement policy and economic conditions, Daymark recommends that Hydro make two key updates to its forecasting methodology:

1. Developing an electricity price forecast inclusive of cost recovery for long-term expansion, and

As electrification rates continue to grow, the impact of consumer price elasticity for electricity becomes more significant. As such, if future consumers become increasingly price sensitive at higher price levels, resource expansion needs may change, particularly when considering loads like electric vehicles.

2. Continually assessing and documenting alternate scenario forecasts.

Hydro has evaluated several alternative load forecasts to account for alternative future scenarios. Hydro should continue to assess these scenarios based on growing industry trends, such as consumer price elasticity, large load growth rates, load shape impacts of distributed energy resources/demand response, and numerous other variables that might impact resource need. These multiple forecasts will allow for Hydro to react to changes in need that require modifications to the resource plan.

Aging Infrastructure and Firm Capacity

To address an immediate need to back-up the LIL on an interim basis, Hydro has extended the operation of Holyrood TGS, Hardwoods GT, and Stephenville GT, through 2030. This decision is based on the lack of readily available cost-effective options for backing up the LIL.

Continuing to rely on aging thermal facilities (i.e., Holyrood TGS, Hardwoods GT, and Stephenville GT) to reliably meet Hydro's on-Island electricity needs is a growing concern. Holyrood TGS was designed as a base load unit, and as such it is ill-equipped to reliably handle the thermal cycling and fast starting requirements to serve as a backup for the LIL, as Hydro has acknowledged.

To better position Holyrood TGS in this backup role, Hydro intends to continue to invest in capital investments to maintain the facility. In addition, operational changes in unit dispatch are being made to improve Holyrood's reliability and responsiveness. During periods of anticipated high demand Holyrood TGS will be placed online prematurely in anticipation of a potential need. Hydro will continue to look to develop operational strategies to optimize the dispatch of the units to manage startup challenges while minimizing cost. While these strategies may be effective in maintaining Holyrood TGS reliability, actual experience is needed to properly evaluate their effectiveness.

Strong consideration should be given to accelerating the replacement of Holyrood TGS, Hardwoods GT, and Stephenville GT prior to 2030. Daymark is aware and very much supportive of Hydro's ongoing efforts to study what would be required to accelerate the integration of renewable energy and new supply in general into the electrical grid.

Given the remote location of the Muskrat Falls units and the rugged and remote nature of the transmission path connecting it to the Island, combined with the potential for growing industrial load requirements in Labrador, treating Muskrat Falls as firm capacity and a direct replacement for on-Island generation merits continuing analysis.

Operational Contingencies

Operational reserve requirements (30- and 10-minute reserves) are driven by what constitutes the largest and second largest single contingency events on the Newfoundland and Labrador Interconnected System. The loss of individual units at Holyrood TGS have historically been considered the largest contingency events. Once the LIL is fully integrated, the Holyrood TGS will be replaced by the individual units at Muskrat Falls as the largest contingency events. Once fully integrated, the loss of a LIL tower technically represents the largest single contingency, double element risk to the IIS. However, during the conceptual and planning phases of the Muskrat Falls project, Hydro specified that the loss of the LIL is not considered as a single contingency given the robust nature of the tower design.

Daymark believes excluding the loss of the LIL as the largest single contingency on the Newfoundland and Labrador Interconnected System merits further review, especially considering the absence of any meaningful operational history for the LIL. Given that a tower failure alone (a software failure could also trigger the same result) would result in a complete bipole outage, Hydro may be better served to treat the LIL as energy only and not as firm capacity or the equivalent of on-Island capacity as is currently the case.

As part of the 2024 RRA, Hydro has studied the implications of treating the LIL as an energy-only line for informational purposes only. Currently, the closest Hydro comes to full alignment with the above concern is the "Shortfall Analysis" with the assumed total bipole loss of the LIL for 6-weeks during a winter peak period. Daymark recognizes the potentially significant cost implications that need to be balanced with the reliability gained from such a shift in planning philosophy.

Minimum Expansion Strategy

Consistent with Hydro's stated goal of providing reasonable reliability at the lowest cost, Hydro has elected to pursue a minimum expansion strategy. This strategy is focused on meeting the minimum expansion requirements common to all planning scenarios studied. This approach, while focused on least cost, could result in Hydro being exposed to greater risk in the event actual circumstances exceed planning assumptions (e.g., higher customer load requirements, poorer reliability performance from existing generation and transmission resources).

While prudent in the short term, in the long-term, Daymark recommends that the Minimum Expansion Strategy be supported by the timely monitoring of load changes and resource capabilities along with the preplanning of additional expansion alternatives to enable accelerated deployment in the event additional need develops. Hydro has several planning related studies either in progress or under consideration. Priority should be given to accelerating their completion. Further, Hydro should also consider issuing an All Source RFI to gauge market interest and available options.

DAYMARK ENERGY ADVISORS

APPENDIX

Table 3: Inflation Matrix[6]

Base Value	100	End Year					
Base Year	Avg. Annual Inflation	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
2018	2.40%	$100.00					
2019	1.80%	$101.80	$100.00				
2020	1.20%	$103.02	$101.20	$100.00			
2021	4.70%	$107.86	$105.96	$104.70	$100.00		
2022	8%	$116.49	$114.43	$113.08	$108.00	$100.00	
2023	4.10%	$121.27	$119.12	$117.71	$112.43	$104.10	$100.00

Cum. Inflation						
	Base Year					
End Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
2018	0.00%					
2019	1.80%	0.00%				
2020	3.02%	1.20%	0.00%			
2021	7.86%	5.96%	4.70%	0.00%		
2022	16.49%	14.43%	13.08%	8.00%	0.00%	
2023	21.27%	19.12%	17.71%	12.43%	4.10%	0.00%

[6] Based on average annual CPI inflation data provided by the U.S. Department of Labor and hosted on https://www.usinflationcalculator.com/inflation/current-inflation-rates/.

Appendix B

Appendix B

Planning Criteria and Study Methodology

Planning Criteria and Study Methodology

newfoundland labrador hydro

Contents

1.0 Introduction 1
2.0 Hydro's Mandate and Regulatory Requirements 1
3.0 Reliability Planning Criteria 3
3.1 Regional and Sub-Regional Planning 4
3.2 Probabilistic Capacity Criterion 6
3.3 Firm Energy Planning Criterion 8
3.4 LIL Shortfall Assessment 9
3.5 Operational Capacity Criterion 9
4.0 Overview of the Resource Planning Process 11
4.1 Modification Required to the Resource Planning Process 14
5.0 Resource Adequacy Study Methodology 15
5.1 Reliability Model Methodology 15
5.1.1 Load Forecast Modelling 17
5.1.1.1 Conservation and Energy Efficiency 19
5.1.1.2 Capacity Assistance and Curtailable Load 21
5.1.1.3 Load Shape Modelling 22
5.1.2 Generation Modelling by Asset Class 22
5.1.2.1 Hydroelectric Generation 23
5.1.2.1.1 Units with Larger Storage Capacities 23
5.1.2.1.2 Units with Smaller Storage/Run-of-River Units 23
5.1.2.1.3 Muskrat Falls 24
5.1.2.2 Thermal and CTs 26
5.1.2.3 Wind Generation 27
5.1.3 Capacity Transfers: Imports and Exports 29
5.1.3.1 Import Potential to the Island Interconnected System 29
5.1.3.1.1 Transmission and Market Access 29
5.1.3.1.2 Firm Capacity 30
5.1.3.2 Import Potential to the Labrador Interconnected System 31
5.1.3.3 Island Interconnected System Export Commitments 31
5.1.3.4 Export Potential via the Labrador-Hydro-Québec Transmission Path 32

5.1.4 Transmission System ... 32
5.1.4.1 The LIL ... 33
5.1.4.2 LIL Shortfall Assessment ... 35
5.1.4.3 Relationship between the LIL and the Maritime Link ... 36
5.1.5 Minimum Regulating Reserve ... 37
5.1.6 Planned Generation Retirements ... 37
5.1.7 Planning Reserve Margin Requirements ... 40
5.2 Operational Reserve Requirements ... 42
5.3 Firm Energy Model Methodology ... 43
5.3.1 Island Interconnected System ... 44
5.3.1.1 Hydro ... 44
5.3.1.2 Wind ... 45
5.3.1.3 Thermal ... 45
5.3.1.4 Transmission ... 46
5.3.1.4.1 The Maritime Link ... 46
5.3.1.4.2 The LIL ... 47
5.3.2 Labrador Interconnected System ... 49
5.4 Expansion Model Methodology ... 50
5.4.1 Transmission ... 51
5.4.1.1 On-Avalon Transmission Constraint ... 51
6.0 Conclusion ... 53

List of Attachments

Attachment 1: Forced Outage Rate Methodology

Attachment 2: “Energy Analysis Memo,” Daymark Energy Advisors, May 9, 2024

1.0 Introduction

The purpose of this document is to provide a detailed overview of Hydro's planning criteria and study methodology that was used to develop the 2024 Resource Plan.[1] The document consists of four main categories, described as follows:

- **Hydro's Mandate and Regulatory Requirements:** An overview of Hydro's mandate and provincial government legislation requirements that dictate Hydro's resource planning.
- **Reliability Planning Criteria**: An overview of the key criteria that guide reliability planning and decision-making to meet Hydro's mandate and regulatory requirements.
- **Overview of the Resource Planning Process**: An overview of the resource planning process as well as any modifications to the process that occurred.
- **Resource Adequacy Study Methodology**: A description of the models Hydro uses as part of the resource planning process, as well as the underlying methodology and key assumptions modelled, including the resulting Planning Reserve Margins used in the development of the Expansion Plan scenarios for the 2024 Resource Plan.

2.0 Hydro's Mandate and Regulatory Requirements

System planning entails the development and assessment of supply adequacy under various potential future realities. Evaluating multiple futures ensures that the 2024 Resource Plan development occurs with an understanding of the impact of the uncertainties which are inherent in electricity system planning. This process is used to ensure that both sufficient firm capacity and firm energy are available to meet customer and system requirements and determine the appropriate timing of requirements for additional resources.

[1] Hydro's 2024 Resource Plan is filed as part of the ongoing *RRA Study Review* proceeding. Hydro's filings within the *RRA Study Review* proceeding are available on the Board's website.
http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/index.php

Hydro is the primary generator of electricity in Newfoundland and Labrador. Hydro has a statutory mandate that is established in the *EPCA*[2] and how that is met is regulated by the Board. The statutory mandate is provided in the *Hydro Corporation Act, 2007* as follows:

> 5. (1) The objects of the corporation are to develop and purchase power on an economic and efficient basis, . . . and to supply power, at rates consistent with sound financial administration, for domestic, commercial, industrial or other uses in the province . . .[3]

The *EPCA* states:

> 6. (1) The public utilities board has the authority and the responsibility to ensure that adequate planning occurs for the future production, transmission and distribution of power in the province.
>
> (2) The public utilities board may direct a producer or retailer to perform such activities and provide such information as it considers necessary for such planning to the public utilities board or to any other producer or retailer on such terms and conditions as it may prescribe.
>
> (3) For the purpose of this section, the public utilities board may adopt those rules and procedures that it considers necessary or advisable to give effect to the subsection.[4]

The *EPCA* was recently modified to provide the ability for consideration of the environment. Legislation now reads:

> 3. (b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner…
>
> > (iii) that would result in power being delivered to consumers in the province at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service.[5]

The future reliability of the Island Interconnected System also formed part of Board Order No. P.U. 3(2014), Schedule "A," which ordered an evaluation of the Island Interconnected System adequacy and reliability up to and after the interconnection with Muskrat Falls. The Order referred specifically to the evaluation of the requirement for "back-up generation and/or alternative supply requirements after

[2] *Electrical Power Control Act, 1994,* SNL 1994, c E-5.1.
[3] *Hydro Corporation Act, 2007,* SNL 2007, c H-17, s 5(1).
[4] *Electrical Power Control Act, 1994,* SNL 1994, c E-5.1, s 6.
[5] *Electrical Power Control Act, 1994,* SNL 1994, c E-5.1, s 3(b) and 3(b)(iii).

interconnection" and "other system planning, capital and operational issues which may impact adequacy and reliability before and after interconnection."[6]

Consistent with Hydro's *RRA Study Review*, the analysis focuses on the ability to reliably meet customer and system requirements over a ten-year planning horizon, covering the period from 2024 through 2034.[7]

3.0 Reliability Planning Criteria

Hydro's resource planning activities are focused on satisfying loss of load criteria while ensuring sufficient resources to meet operational reserves and sufficient resources to meet energy requirements. Hydro's reliability planning criteria consists of long-standing criteria that have been used to meet system reliability for decades. In addition, more recent planning criteria have been included to reflect the interconnection to the North American Grid via the Maritime Link and the completion of the LIL that delivers power from Muskrat Falls to the Soldiers Pond TS on the Avalon.

Supply expansion decisions are based on Hydro's previously established[8] resource planning criteria, detailed as follows:

- **Probabilistic Capacity:** The Island Interconnected System should have sufficient generating capacity to satisfy a LOLH expectation target of not more than 2.8 hours per year.[9,10]
- **Energy:** The Island and Labrador Interconnected Systems should have sufficient generating capability to supply all its firm energy requirements with firm system capability.

[6] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 3(2014), Board of Commissioners of Public Utilities, February 19, 2014, sch. A, p. 2/4–6.
[7] Reporting on a ten-year planning horizon is observed in the "2023 Long-Term Reliability Assessment," North American Electric Reliability Corporation, December 2023. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf
[8] The establishment of the probabilistic capacity criteria occurred in the 1980s and the firm energy criteria in the 1990s.
[9] The previous resource adequacy target of two outage days in ten years, or an LOLE of 0.2, was chosen at the time over the alternative criteria of one day in ten years, or an LOLE of 0.1, to decrease cost of meeting target. A change in software necessitated a benchmarking process to translate the LOLE to LOLH, at which point it was determined that the LOLE of 0.2 could be approximated as an LOLH of 2.8 hours per year.
[10] Further discussion on 0.1 LOLE versus 2.8 LOLH planning criteria can be found in Section 5.1.7.

Additional capacity criteria were established by Hydro in the 2018 Filing, detailed as follows:

- **LIL Shortfall Assessment:** The Island Interconnected System should have sufficient generating capacity to limit the loss of load to a manageable level in the case of a LIL shortfall event.[11]

Additionally, Hydro has proposed to adopt the following operational criteria, as established in the 2018 Filing:

- **Operational Capacity:** The Newfoundland and Labrador Interconnected System should have sufficient generating capacity to meet its peak load while maintaining in reserve the equivalent capacity of its largest generator contingency plus 50% of the capacity of its second largest contingency.

More detail on the Island Interconnected System and the Labrador Interconnected System planning criteria are provided in Sections 3.1 through Section 3.5.

3.1 Regional and Sub-Regional Planning

In the 2018 Filing and 2019 Update, Hydro recommended planning on a regional (Newfoundland and Labrador Interconnected System) and sub-regional (Island Interconnected System) basis. At that time, planning on a Newfoundland and Labrador Interconnected System basis was appropriate given the assumed LIL bipole EqFOR of 0.0114%. This meant that future load growth on either the Labrador Interconnected System or the Island Interconnected System had approximately the same impact on Newfoundland and Labrador Interconnected System reliability. However, given the reliance on the LIL as a source of supply to the Island, it was prudent to incorporate specific consideration of the Island Interconnected System should the LIL not be available. By adopting a separate requirement for the Island Interconnected System, the planning process ensured continued reliability for both the province and on the Island.

From a capacity perspective, as the LIL bipole EqFOR has materially increased from 0.0114% to an assumed range of 1% to 10% and LIL bipole outages become the primary driver of generation shortfall

[11] The loss of the LIL bipole is considered to be a high consequence event impacting the Island Interconnected System. While it does not have specified planning criteria, planning to mitigate the consequences of a prolonged LIL outage is essential and Hydro continues to evaluate reliability implications of an extended LIL outage as part of the resource planning process.

on the Island Interconnected System, there is far less correlation between the Labrador Interconnected System demand and the Newfoundland and Labrador Interconnected System reliability.

In the 2022 Update, Hydro committed to reassessing the following planning criteria due to the decrease in expected long-term LIL bipole availability for the next Resource Adequacy Plan update:

- Planning for the Newfoundland and Labrador Interconnected System on a regional and sub-regional basis;
- Adoption of a system reserve margin that satisfies LOLE ≤ 0.1 for the Newfoundland and Labrador Interconnected System;
- Adoption of a system reserve margin that satisfies LOLE ≤ 0.1 for the Island Interconnected System; and
- Extending pre-existing Island Interconnected System energy criteria to the Newfoundland and Labrador Interconnected System.

In Hydro's analysis, Muskrat Falls generation is assumed to be fully available for the Island Interconnected System. Therefore, during the winter months, the LIL's capacity is maximized via deliveries from Muskrat Falls generation and there is little (if any) ability for additional sources of generation to be brought to the Island. Therefore, an increase in Labrador demand would not impact Island Interconnected System reliability as the LIL is already maximized by Muskrat Falls generation. Load growth requirements in Labrador would have to be met by new generation sources in Labrador. Subsequently, a theoretical decrease in Labrador demand would not make a significant amount of additional capacity available to the Island Interconnected System, as the LIL is fully utilized in the winter period via deliveries from Muskrat Falls generation. Therefore, given the material increase of the LIL bipole EqFOR assumption and consideration of the designed capacity of the LIL, it has become necessary to reassess this approach and instead adopt separate planning criteria for the Island Interconnected System and the Labrador Interconnected System as two separate regions.

From an energy perspective, it is also necessary to decouple the two interconnected systems. Further analysis has been completed to define the operational relationship between LIL flow, Island Interconnected System demand, and Maritime Link flow. Under normal system conditions, the amount of energy that can flow over the LIL to the Island is limited by the interdependencies with the Maritime Link and Island load. This interdependence exists because both HVdc links must work together using RAS that will suddenly reduce their power flows (runbacks) to transiently regulate system frequency in the event a contingency occurs on the other HVdc link. This LIL to Maritime Link relationship has less of an impact on the amount of power that can be absorbed on the Island than the amount of UFLS that is available and would be triggered following a bipole trip. The amount of available UFLS is directly proportional to the total Island load.[12] As a result, it is now confirmed that there are restrictions on the amount of energy that is able to flow from Muskrat Falls to the Island, resulting in the recommendation to consider the two regions independently when assessing firm energy requirements.

Planning for the Island and the Labrador Interconnected Systems as two separate regions remains true as the system stands today; however, Hydro recognizes that both the Island and the Labrador Interconnected Systems have unique challenges and are connected by one bipole HVdc transmission line that can only flow energy to the Island Interconnected System—the LIL. Therefore, should significant load growth, driven by industrial need, occur in the Labrador Interconnected System, there continues to be merit to plan for the Labrador Interconnected System as a separate region to ensure reliability in Labrador is met, which may require the development of Labrador-specific planning criteria in the future. This also holds true should new sources of supply materialize in Labrador. If this were to occur, any additional capacity and/or energy would not improve reliability for the Island Interconnected System region as deliveries would remain limited by the LIL's transfer capability to the Island. Therefore, any additional resources that may be constructed in Labrador would not support the Island Interconnected System as the LIL design capacity is near-maximized by the existing generation in Labrador. All analysis completed for this study has been done in consideration of the Island Interconnected System and the Labrador Interconnected System as two separate regions.

Further discussion on the adoption of a system reserve margin that satisfies LOLE ≤ 0.1 for the Island Interconnected System is included in Section 3.2. Further discussion on extending the existing firm energy criteria on a regional basis is included in Section 3.3.

3.2 Probabilistic Capacity Criterion

Loss of load metrics provide a probabilistic assessment of system reliability. This helps to quantify the likelihood that a utility will not be able to meet its load requirements at a point in time, considering

[12] Please refer to Section 5.1.4.3 for additional information on this relationship.

numerous potential operating scenarios that can occur. In other words, loss of load metrics evaluate the instances in which system load exceeds the available generating capability.[13]

In the 2018 Filing and 2019 Update, Hydro proposed that both the Newfoundland and Labrador Interconnected System (region) and the Island Interconnected System (sub-region) should each have sufficient generating capacity to meet the reliability planning criteria of LOLE of no more than one day in ten years (i.e., 0.1 LOLE) at a point in the future where the Muskrat Falls Project Assets are fully integrated and proven reliable, and the Holyrood TGS, Hardwoods GT, and Stephenville GT are retired. The adoption of the LOLE metric with the target of LOLE ≤ 0.1[14] increases planned system reliability from that planned based on the existing probabilistic criterion of LOLH ≤ 2.8. At that time, the reliability assessment analysis suggested that an increased level of reliability was economically achievable based on the LIL reliability and operability assumptions.

In the 2022 Update, Hydro committed to reassessing the recommendation to adopt the LOLE metric as the LIL reliability and operability assumptions evolved and the subsequent impacts of those assumptions on the Island Interconnected System reliability were realized.

Currently, Hydro maintains that the adoption of the LOLE metric with the target of LOLE ≤ 0.1 increases planned system reliability from that which is planned based on the existing probabilistic criterion of LOLH ≤ 2.8, as it necessitates a larger level of required reserves and a corresponding increase in reliability. However, Hydro has concluded that the adoption of a planning criteria target of LOLE ≤ 0.1 for the Island Interconnected System remains cost-prohibitive at this time and recommends maintaining the existing probabilistic criterion of LOLH ≤ 2.8. This does not preclude the potential for adopting more stringent planning criteria in the future. Hydro will continue to assess the potential of adopting LOLE ≤ 0.1 in consideration of the balance between cost and reliability as aging thermal assets are retired and new assets are integrated into the Island Interconnected System. The impact of LIL reliability on the Planning Reserve Margin requirements for each metric (LOLE and LOLH) is discussed in more detail in Section 5.1.7.

[13] There are four generally accepted types of probabilistic metrics against which system reliability is measured—LOLP, LOLE, LOLH, and EUE.

[14] Many utilities throughout Canada and across North America have adopted reliability metrics that follow guidelines established by NERC. The use of 0.1 LOLE is more in line with what is commonly used across North America.

Further, as the Island and the Labrador Interconnected Systems are being planned as two separate regions, Hydro does not recommend extending the Island Interconnected System planning criteria of 2.8 LOLH to the Labrador Interconnected System. Development in Labrador is important to Hydro and the province; there continues to be merit in planning for the Labrador Interconnected System as a separate region to ensure reliability in Labrador is maintained.

As it stands today, the Labrador Interconnected System has very low supply risk due to the nature of the existing Churchill Falls contract. A full plant outage would be required at Churchill Falls before a generation shortfall could impact on the Labrador Interconnected System. Therefore, should significant load growth driven by industrial need occur in the Labrador Interconnected System, or should the current source of supply in Labrador change due to future Churchill Falls contract negotiations, there will be a requirement to develop separate planning criteria for the Labrador Interconnected System.

As LIL reliability remains a key factor in the ability to economically achieve more stringent planning criteria, Hydro is committed to continuing to evaluate the costs associated with migrating to LOLE ≤ 0.1 as it gains a better understanding of LIL reliability through multiple years of operational experience. The cost associated with planning to LOLE ≤ 0.1 is included in the Expansion Plan.[15] For the 2024 Resource Plan, Hydro's recommended Island Interconnected System Planning Reserve Margin and Expansion Plan is based on the probabilistic criterion of LOLH ≤ 2.8.

3.3 Firm Energy Planning Criterion

The Newfoundland and Labrador Interconnected System energy criteria are such that the Island and the Labrador Interconnected Systems should have sufficient generating capability to supply all its firm energy requirements with firm system capability.[16]

The Newfoundland and Labrador Interconnected System relies primarily on energy from hydro generation to supply its energy requirements which were determined separately for the Island and the Labrador Interconnected Systems. Further discussion on the firm energy methodology can be found in Section 5.3. The results of the firm energy analysis are presented in Section 3.0 of Appendix C.

[15] Please refer to Section 6.3.1 in Appendix C.
[16] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood TGS) is based on energy capability adjusted for maintenance and forced outages.

3.4 LIL Shortfall Assessment

The LIL shortfall assessment is an extended LIL bipole outage scenario that assumes the LIL is unavailable for six weeks during the coldest period of the year (i.e., January and February) to quantify the impact on system reliability. The LIL extended outage is intended to simulate an icing situation that causes a tower collapse in a remote segment of the transmission line; however, the extended outage scenario could generally apply to any prolonged outage event. It is important to note that there is a risk that such an outage could have a duration longer than six weeks. While it does not have specified planning criteria, planning to mitigate the consequences of a prolonged LIL outage is essential and Hydro continues to evaluate reliability implications of an extended LIL outage.

3.5 Operational Capacity Criterion

Hydro continues to assess deterministic capacity planning criteria to bring reliability metrics used in the Newfoundland and Labrador Interconnected System more in line with those commonly used across North America, as it remains economically feasible to do so. The NPCC is an example of utility best practice and their requirements state that compliant utilities will ensure that:

> Each Balancing Authority shall have <u>ten-minute reserve</u> available to it that is at least equal to its <u>first contingency loss</u> . . . Each Balancing Authority shall have <u>thirty-minute reserve</u> available to it that is at least equal to one-half its <u>second contingency loss</u>. [emphasis added][17,18]

In the Newfoundland and Labrador Interconnected System, Hydro considers the first contingency loss to be the loss of a generating unit at Muskrat Falls and the second contingency loss to be the loss of a second unit at Muskrat Falls with a winter firm plant total output of 824 MW (i.e., four 206 MW units). As such, Hydro will plan for the availability of the following operational reserves for the Newfoundland and Labrador Interconnected System to align with these criteria.[19]

---

[17] The Balancing Authority is defined by NERC as "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. Please refer to "Definitions used in the Rules of Procedure," North American Electric Reliability Corporation, June 27, 2024, app. 2, p. 2.
https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix%202%20eff%2020240627_signed.pdf
[18] "Regional Reliability Reference Directory # 5 Reserve," Northeast Power Coordinating Council, rev. September 27, 2019 (originally issued December 2, 2010) sec. 5 R1–R2.
https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/regional-criteria/directories/directory-5-reserve-20200426.pdf
[19] This is based on the per unit contribution to the firm plant output of Muskrat Falls (824 MW).

- **10-Minute Reserves:** Hydro shall have a 10-minute reserve available to it at least equal to 206 MW to cover its first contingency loss, where the first contingency loss is the loss of a single unit (of the four available for operation) at Muskrat Falls.[20]
- **30-Minute Reserves:** Hydro shall have a 30-minute reserve available to it at least equal to 103 MW to cover one-half the magnitude of its second contingency loss (0.5 × 206 MW), where the second contingency loss is the loss of a second unit at Muskrat Falls.[21]

In total, Hydro will maintain a minimum operating reserve for the Island Interconnected System of 309 MW.[22] These criteria is considered independent of the probabilistic capacity criteria.

[20] The loss of the LIL bipole would be a worst-case contingency in terms of capacity impact. However, only the loss of generation is considered from an operating reserve standpoint. For a loss of generation, operating reserves are maintained to ensure that tie-line flows are rebalanced within specified timeframes. Loss of the LIL bipole would result in the curtailment of exports in accordance with contractual arrangements and outages to Island customers. Following the bipole outage, customers will be restored to the extent generation is available.

[21] The loss of the LIL bipole would be a worst-case contingency in terms of capacity impact. However, only the loss of generation is considered from an operating reserve standpoint. For a loss of generation, operating reserves are maintained to ensure that tie-line flows are rebalanced within specified timeframes. Loss of the LIL bipole would result in the curtailment of exports in accordance with contractual arrangements and outages to Island customers. Following the bipole outage, customers will be restored to the extent generation is available.

[22] The addition of the 10-minute reserve requirement (206 MW) and the 30-minute reserve requirement (103 MW) yields a minimum operating reserve requirement of 309 MW.

4.0 Overview of the Resource Planning Process

Figure 1 is a flowchart that provides a visual representation of Hydro’s resource planning process.

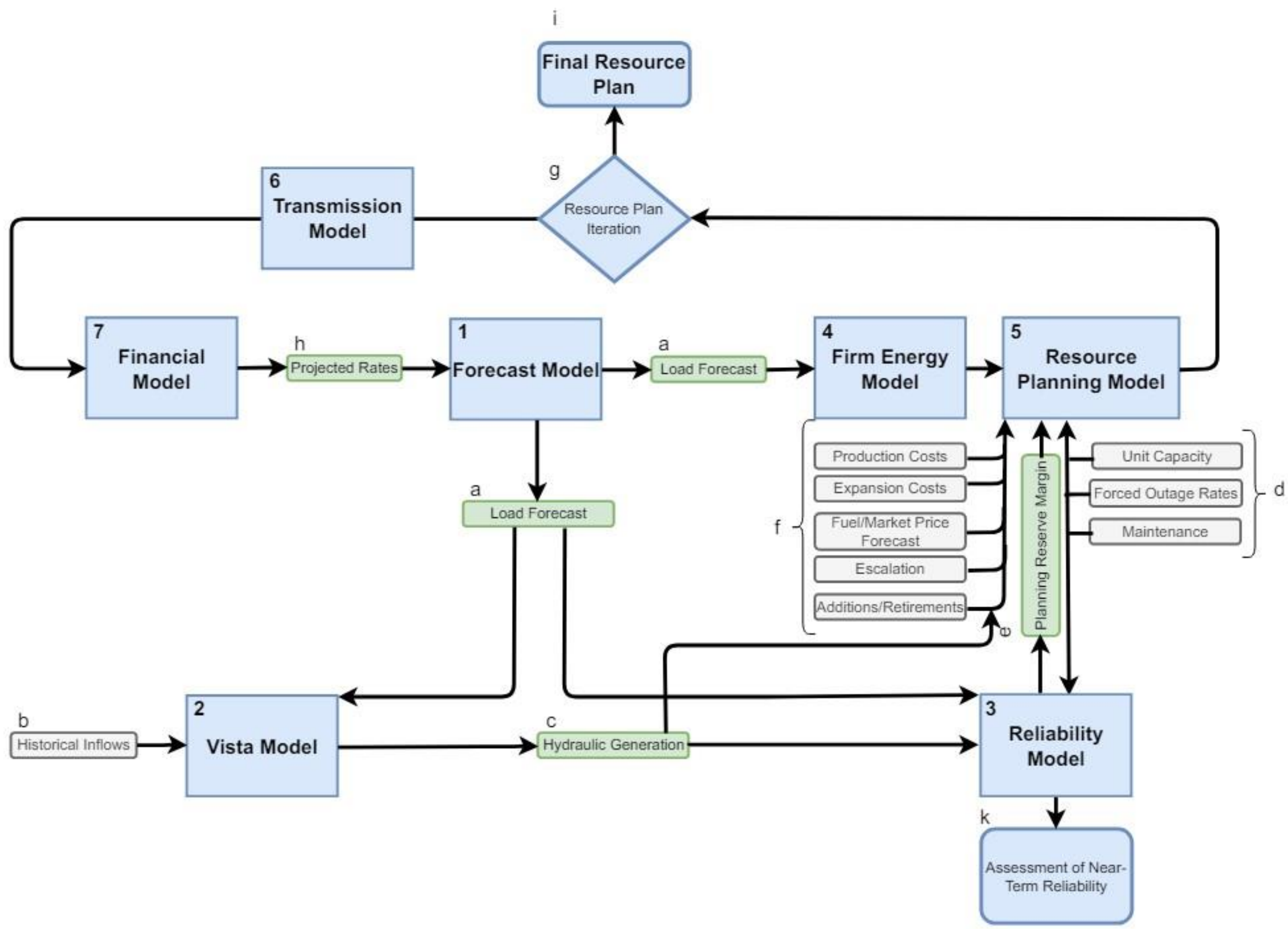


Figure 1: Resource Planning Process Flowchart

Numbered boxes in Figure 1 define the key steps in the process whereas lettered boxes define outputs and/or inputs to the key steps. In summary, the Forecast Model develops the forecast of annual energy and capacity which underly the remaining resource planning steps including:

- The Vista Model, which produces the contribution of hydraulic (also referred to as “hydroelectric”) generation;
- The Reliability Model, which performs a stochastic analysis of the systems ability to meet load and determines the reserve margins necessary to meet the probabilistic capacity criteria that are inputted into the Resource Planning Model;

- The Firm Energy Model, which provides an assessment of firm energy requirements;
- The Resource Planning Model (i.e., Expansion Model), which provides an assessment of new resource needs based on the ability of existing resources to meet the forecast need while maintaining the required reserves and firm energy requirements determined in the previous step;
- The Transmission Model, which determines the transmission upgrades required; and
- The Long-Term Financial Model, which determines the impact of the required investment on customer rates.

More detailed summaries of each resource planning tool are provided below with greater detail in the sections that follow.

The process begins with the development of the system load forecasts using Hydro's **Load Forecast Model** [1]. The load forecasts provide projections of the system's annual peak demand and annual energy requirements. Standalone load forecasts are prepared for both the Island and Labrador Interconnected Systems and these are used as input throughout the modelling process [a].

The energy requirements of the load forecasts [a] and the historical inflows on the hydraulic record [b][23] are used by the **Vista Model** [2] to generate a forecast of average hydraulic generation [c].[24] The forecast of hydraulic generation [c] is then used in the **Reliability Model** [3] and **Resource Planning Model** [5].

The **Reliability Model** [3] is used to assess anticipated system reliability during the forecast period based on numerous parameters, including unit and plant reliability. It is used to determine the target Planning Reserve Margin [e], that is, the quantity of reserve that must be held (i.e., extra capacity that must be available over and above the forecast peak load) to satisfy reliability requirements. To do so, the reliability model considers the capacity requirements developed in the load forecast [a], the hydraulic generation forecast identified by Vista [c], and several key unit parameters focused on unit and plant reliability [d]. To ensure that the reliability model results are robust, there is a measure of uncertainty applied to the modelling inputs. These uncertainties are incorporated by introducing randomness (e.g.,

[23] Hydro's modelled hydraulic record currently consists of 73 years of hydraulic inflows.
[24] Note that assessment of Hydro's ability to meet forecast customer and system energy requirements in consideration of the full hydraulic record is conducted in Vista.

timing of unit forced outages), and/or modelling a specific uncertainty profile (e.g., the weather-driven load forecast uncertainty profile). Monte Carlo Simulation techniques are then used to simulate the probable range of operating scenarios to ensure the resultant Planning Reserve Margin [e] accounts for the uncertainties inherent in the future operation of the system.

The **Firm Energy Model** [4] determines the firm energy requirements that meet Hydro's planning criteria, in consideration of the load forecasts [a].

The **Resource Planning Model** [5] considers the existing supply capability, the load forecasts [a], the Planning Reserve Margin [e], as well as firm energy requirements to determine whether and in what time frame the system may be resource deficient. Additional inputs to the Resource Planning Model include unit parameters [d] and other system costs and financial components [f], including the representation of future resource options. The Resource Planning Model determines the least-cost resource plan [g] which satisfies system reliability requirements. The resource options include renewable and non-renewable, and dispatchable and non-dispatchable resources that can be constructed. Further discussion on the resource options can be found in the 2024 Expansion Plans.[25]

The resource plan [g] is then modelled in Hydro's **Transmission Model** [6] to determine whether upgrades are required to meet load during a LIL bipole outage. Specifically, an assessment is completed to determine if upgrades are required to increase flow from off Avalon (where the majority of Hydro's existing and future resources are located) to on Avalon (a large load centre within the Island Interconnected System). The timing of the upgrades required and the cost are then considered in the development of the resource plan [g] to ensure the full cost associated with meeting future demand is captured.

The resource plan, including the transmission upgrade requirements, is then modelled in Hydro's Long-Term **Financial Model** [7] to determine the impact of the required investment on projected customer rates [h]. As a commodity, the demand for electricity is elastic, meaning that electricity customers exhibit some sensitivity to price. Projected investment costs likely increase projected electricity rates, resulting in a decrease in forecast customer load requirements. This decrease can be material enough to

[25] Please refer to Section 4.0 of Appendix C.

then defer the timing of the required investment. The project rates [h] associated with a resource plan [g] are used to determine the impact on forecasted load requirements.

As resource additions are identified as part of the 2024 Resource Plan, Hydro's Major Projects Department would begin the process to advance the recommended project(s). Hydro is currently reviewing processes from other Canadian utilities to develop a formal phased life cycle approach[26] that is typical of large construction projects. Hydro is working with internal stakeholders to develop the approach and is planning engagement with relevant external parties to align on the process, including key decision points and criteria for approval.

4.1 Modification Required to the Resource Planning Process

The process outlined in Figure 1 details Hydro's traditional approach to resource planning. However, the impact of customer rates following the in-service of the Muskrat Falls Project Assets required a modified approach to support the development of additional information pertinent to the *Reference Question*.[27]

As rate mitigation had not yet been finalized prior to the development of the 2023 load forecast and the analysis presented herein, the assumed mitigated rate that formed the basis of the rate included in the 2023 Reference Case load forecast was the target mitigated rate that was announced publicly by GNL in 2019 and 2021,[28,29] targetting 14.7¢/kWh, escalating by 2.25% per year. This rate forecast was used in both the Reference Case and Accelerated Decarbonization load forecasts.

For the Slow Decarbonization load forecast, Hydro created an assumed rate sensitivity forecast considering the underlying mitigated electricity rate forecast and added a 0.7% adjustment based on the historical rate impact of the Newfoundland Power System (reflects an increase in Newfoundland Power's costs of 2.0% per year).

[26] The application of well-defined checkpoints, especially early in the project life cycle, provides management and relevant parties with an informed assessment of progress and issues, a validation of the project justification, and ultimately leads to better decisions on plans and investments for the future.

[27] "*Reference on Rate Mitigation Options and Impacts Relating to the Muskrat Falls Project Costs*," Newfoundland and Labrador Board of Commissioners of Public Utilities, Media Release, October 16, 2018. http://pub.nl.ca/applications/2018/2018ratemitigation/notices/Media%20Release%20-%20Rate%20Mitigation%20Options%20and%20Impacts%20-%20FINAL%20-%202018-10-16.pdf

[28] "Protecting You from the Cost Impacts of Muskrat Falls," Government of Newfoundland and Labrador, April 2019. https://www.gov.nl.ca/iet/files/Framework.pdf

[29] GNL's rate mitigation target of 14.7 ¢/kWh, escalating at 2.25% per year, as referenced in the "Technical Briefing Rate Mitigation," Government of Newfoundland and Labrador, July 28, 2021 filed as part of the "Items Impacting the Delay of Hydro's Next General Rate Application – Further Update," Newfoundland and Labrador Hydro, August 27, 2021.

In addition, two rate sensitivities were applied against the recommended Expansion Plan to further test the impact of rates on the plan.

Although the rate mitigation plan does not currently provide certainty around the period post-2030, GNL has stated publicly that they are committed to keeping rates affordable for the people of the province Hydro will work with GNL in advance of 2030 to determine future rate mitigation requirements once more information on the landscape of the electricity sector in that period is known and rate impacts of required system expansion are better understood. Further discussion on rates is included in the 2024 Expansion Plans.[30]

All inputs in the resource planning process flowchart were completed with one resource plan iteration [g] for select expansion plans that flowed through the Rates Model, the Forecast Model, and the Resource Planning Model to determine the impact on the rates and the recommended Expansion Plan.

5.0 Resource Adequacy Study Methodology

The methodology and modelling approach used to assess resource adequacy for the Island and Labrador Interconnected Systems are discussed in the following sections:

- Section 5.1: Reliability Model Methodology;
- Section 5.2: Operational Reserve Requirements;
- Section 5.3: Firm Energy Model Methodology; and
- Section 5.4: Resource Planning (Expansion Model) Methodology.

5.1 Reliability Model Methodology

As in previous *RRA Study Review* filings, the analysis of system reliability was completed using Hydro's Reliability Model,[31] in accordance with the NERC guidelines for probabilistic analysis to ensure alignment with industry accepted practice. The Reliability Model is a stochastic system model created using the PLEXOS modelling platform. The model is used to determine probabilistic measures of system reliability (LOLH, LOLE, and EUE) and to probabilistically assess outage severity in the LIL Shortfall Assessment. The assessment of system reliability is the foundation of the determination of the Planning Reserve Margin,

[30] Please refer to Section 7.4.1 of Appendix C.
[31] The Reliability Model is a detailed hourly system model implemented in PLEXOS using Monte Carlo simulation to determine system reliability in terms of LOLH, LOLE, and EUE.

which is a key input into developing the recommended Expansion Plan. While long-term investment requirements are identified using the Planning Reserve Margin process, this process is complemented by the evaluation of near-term supply adequacy, which is reported in the annual Near-Term Reliability Report.[32] The granular near-term view provides insight into the impact of seasonal load and generation variations on supply events. This can be used to further inform the decision on which resource options are best suited to meet evolving system requirements.

The Reliability Model focuses on a single representative year, with the resulting Planning Reserve Margins applied to the entire study period (2024–2034). To ensure that incremental investment is made prudently, it is important to select a representative year that most closely represents anticipated long-term system conditions. As capacity additions and retirements occur, the relationship between the probabilistic capacity planning measure of LOLH ≤ 2.8 and the reserve margin changes, particularly if the attributes of the resources being added or removed from the system are materially different. For example, the Holyrood TGS (which has a planning DAUFOP of 20%) has a significantly different impact on the required Planning Reserve Margin than a hydroelectric unit (with its long-term planning DAFOR of 3.03%). The increased reliability of newer and more reliable units reduces the actual Planning Reserve Margin required. Further, the relationship is also dependent on the size of the resource being added to the resource mix. For example, the addition of multiple smaller units will improve the reliability of the system more than the addition of a single larger unit with an equivalent total capacity. In general, the more the system resource characteristics deviate from the selected representative year, the less accurate the reserve margin will be. Therefore, the representative year's calculated reserve margin would not necessarily apply to the system if the year selected was prior to the retirement of the Holyrood TGS. The year 2032 was selected as the representative year since at that time, all currently proposed capacity resource additions and planned retirements are expected to have occurred. The selection of the representative year is for the purpose of establishing the reliability criteria only.

The following sections discuss the methodology surrounding development of each of the main inputs to the Reliability Model:

- Section 5.1.1: Load Forecast Modelling;

[32] The most recent Near-Term Reliability Report was filed in November 2023. For additional information on near-term reliability, please refer to "2023 Near-Term Reliability Report," Newfoundland and Labrador Hydro, November 15, 2023.

- Section 5.1.2: Generation Modelling by Asset Class;
- Section 5.1.3: Capacity Transfers: Imports and Exports;
- Section 5.1.4: Transmission System;
- Section 5.1.5: Minimum Regulating Reserve; and
- Section 5.1.6: Planned Generation Retirements.

Ultimately resulting in the Planning Reserve Margin requirements for the Island Interconnected System, which are included in Section 5.1.7.

5.1.1 Load Forecast Modelling

The load forecast is a key input to the resource planning process that projects electric power demand and energy requirements through future periods. The Newfoundland and Labrador Interconnected System load forecast is segmented by the Island Interconnected System, Labrador Interconnected System, and rural systems as well as by utility load (i.e., domestic and general service loads of Newfoundland Power and Hydro) and industrial load.[33] The load forecast process entails translating a long-term economic and energy price forecast for the province into corresponding electric demand and energy requirements for the electric power systems. The load forecasts for the Island and Labrador Interconnected Systems were prepared during the third quarter of 2023 and cover the period from 2023 through 2034.[34] Overall, the load forecast is showing growth across the provincial system, stemming from several factors including:

- Increasing population growth when compared to prior forecasts utilizing the GNL forecasts;
- Ongoing electrification activities, primarily resulting from actions taken by the provincial and federal governments to mitigate climate change and where possible, utilizing third-party expert input, such as Dunsky for electric vehicle adoption rates; and
- Existing industrial customer’s firm requests related to expansion and decarbonization of their operations.

[33] Hydro has six industrial customers on the Island and two industrial customers in Labrador.
[34] For additional information on the development of the 2023 Load Forecast, refer to the, “Long-Term Load Forecast Report – 2023,” Newfoundland and Labrador Hydro, March 28, 2024.

Industry changes, as well as policy changes in response to concerns about climate change, have accelerated compared to what has been seen in recent years, and there remains uncertainty regarding timing and adoption rates for new technology. This uncertainty is captured by developing alternate forecast scenarios that allow for evaluation of the sensitivity of results to differing economic conditions and load growth opportunities. For this planning exercise, a range of load forecasts were developed independently for the Island and the Labrador Interconnected Systems. For the 2024 Resource Plan, three forecasts were developed to reflect the range of forecasted Island Interconnected System load requirements, as summarized in Figure 2.

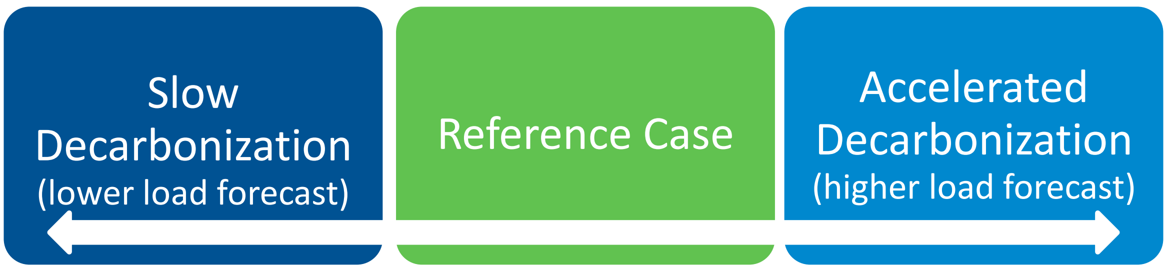


Figure 2: Island Interconnected System Forecast Scenarios

- **Slow Decarbonization:** Considers more moderate decarbonization efforts and electrification of the transportation sector, lower population and housing starts, as well as increased electricity rates, resulting in a lower load forecast as compared to the Reference Case;
- **Reference Case:** Based upon the continuation of a steady level of decarbonization, driven primarily through government policy and programs, anticipated electrification of the transportation sector, and steady increase in population and housing starts; and
- **Accelerated Decarbonization:** Assumes accelerated decarbonization and electrification of the transportation sector, electricity rate assumptions consistent with the Reference Case,[35] as well as higher population and housing starts, and an increase in industrial demand, resulting in a higher load forecast as compared to the Reference Case.

Similarly, three forecast scenarios were developed for the Labrador Interconnected System to reflect the potential range of load forecast requirements for that system. Considering the current customer service requests from existing industrial customers asking to significantly increase load in this area, Hydro has

[35] Electricity rates assumptions for the Reference Case are discussed further in Section 4.1.

chosen to develop sensitivity cases to assess how industrial growth could affect system demand and energy requirements. As a result, the Reference Case, which includes no new industrial load, reflects the low side of the potential future outcomes. The three forecasts are summarized in Figure 3.

Figure 3: Labrador Interconnected System Forecast Scenarios

- **Reference Case:** Reflective of current decarbonization efforts and industrial loads;
- **Medium Growth Scenario:** Primarily reflective of increased industrial requirements, resulting in a higher load forecast than the Reference Case; and
- **High Growth Scenario:** Reflective of accelerated decarbonization through electrification and increased industrial requirements, resulting in a higher load forecast than both the Reference Case and Medium Growth Scenario.

In consideration of determining the Island Interconnected System Planning Reserve Margins, only the Labrador Interconnected System Reference Case forecast was included in the Reliability Model in combination with the Island Interconnected System Reference Case and load forecast scenarios, due to the fact that load growth in Labrador does not impact reliability on the Island Interconnected System, as discussed previously in Section 3.1.

The calculated Island Interconnected System Planning Reserve Margins considered in the Expansion Model are discussed in more detail in Section 5.1.7. Planning Reserve Margins were not calculated for the Labrador Interconnected System, as the probabilistic planning criteria is not currently used for Labrador, as discussed previously in Section 3.2.

5.1.1.1 Conservation and Energy Efficiency

Hydro and Newfoundland Power offer a variety of information and financial support options to customers on the Island Interconnected System to help them manage their energy usage. Since 2009, both utilities have offered customer energy conservation programs on a joint and coordinated basis under takeCHARGE.

Examples of the residential programs offered include insulation and air sealing, high-performance thermostats, heat recovery ventilators, and various small technologies through the Instant Rebates Program. takeCHARGE also serves the commercial sector through the Business Efficiency Program and, in more recent years, a pilot program targeting small business customers was introduced.

For the 2023 Load Forecast update, an estimate of energy savings through utility conservation programs, as forecast by takeCHARGE, was developed. This estimate was used for all three load forecast scenarios for the Island Interconnected System.

Over the last decade, the installation of MSHPs in residential homes has grown in popularity, with Newfoundland Power's 2022 customer survey estimating that approximately 28% of their domestic customers have an MSHP installed. In homes with electricity as the primary heating source, MSHPs are primarily being installed to reduce overall energy consumption.[36] For the 2023 Load Forecast update, forecasts were developed for the number of primarily electrically heated residential homes installing an MSHP. While non-electrically heated homes also install MSHPs, for forecast purposes it was assumed all non-electrically heated homes installing an MSHP are reflected in projections associated with the Oil-to-Electric Conversion Program.

In the Reference Case and the Accelerated Decarbonization scenario, it is assumed that by the end of 2034 approximately 61% of Newfoundland Power's residential customers who use electricity as their primary heating source will have installed MSHPs in their homes.[37]

In the Slow Decarbonization scenario, it is assumed that by the end of 2034, 66% of Newfoundland Power's residential customers with electric heat will have installed MSHPs in their homes, slightly more than the Reference Case and the Accelerated Decarbonization scenario due to the increase in electricity rates underlying the load forecast driving electricity-saving measures.[38]

[36] "2021 Conservation and Demand Management Report," Newfoundland Power Inc., April 1, 2022, app. B. http://www.pub.nf.ca/indexreports/conservation/From%20NP%20-%202021%20Conservation%20and%20Demand%20Management%20Report%20-%202022-04-01.PDF
[37] Based on Newfoundland Power's 2022 residential customer count.
[38] Based on Newfoundland Power's 2022 residential customer count.

5.1.1.2 Capacity Assistance and Curtailable Load

Hydro and CBPP agreed to new terms and conditions for a long-term (15-year) CAA which was approved by the Board in Board Order No. P.U. 32(2023).[39] In addition, a new CBPP Co-Gen PPA was agreed to a ten-year term for both firm and non-firm power from the 15 MW co-gen plant at CBPP's site and/or its hydroelectric units.

Newfoundland Power curtailable load is included for 12 MW firm. To help manage system peaks, Hydro periodically makes calls for curtailment from Newfoundland Power, who in turn shed curtailable load with participating customers. Hydro did not make any calls for curtailment from Newfoundland Power in 2024; however, the 2024 curtailment test confirmed that 12.7MW were available.[40]

Vale's increased load requirements in the fourth quarter of 2025 are associated with the conversion of oil-fired boilers to electric heating. The additional electric load is included in the Island Interconnected System Accelerated Decarbonization load forecast only and is assumed 100% curtailable upon Hydro's request as a planning assumption that is relied on in Hydro's analysis. In 2023, Vale indicated that the project was not expected to proceed as previously anticipated; therefore, it was removed from all of Hydro's load forecasts with the exception of the Accelerated Decarbonization load forecast. Should this project proceed in the future, the duration and extent of the load curtailment would need to be negotiated with Vale.

For all load forecast scenarios, it is assumed that the contract for capacity assistance with Vale diesel generation is renewed for each winter season in the study period.

Table 1 summarizes the installed and firm capacity assistance and curtailable load on the Island Interconnected System. Only firm capacity was included in the Reliability Model.

---

[39] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 32(2023), Board of Commissioners of Public Utilities, December 18, 2023.
[40] "2024 Curtailable Service Option Report," Newfoundland Power Inc., April 30, 2024. http://www.pub.nf.ca/indexreports/curtailable/From%20NP%20-%202024%20Curtailable%20Service%20Option%20Report%20-%202024-04-30.PDF

Table 1: Island Interconnected System Capacity Assistance and Curtailable Load (MW)

Capacity Assistance and Curtailable Load	Installed Capacity	Firm Capacity
CBPP Capacity Assistance: Winter[41]	90	90
MUN Curtailable Load	21.7	21.7
NP Curtailable Load	12	12
Vale Curtailable Load	26.8	N/A
CBPP Co-Gen[42]	15	8
Vale Capacity Assistance: Diesel Generation	7.5	7.5
Total Capacity Assistance	**173.0**	**139.2**

There are no capacity assistance or curtailable load agreements assumed available on the Labrador Interconnected System in the representative year (2032).

5.1.1.3 Load Shape Modelling

To develop a load shape that is representative of actual system load profiles for the Island Interconnected System, Hydro uses a base hourly load profile from a year with average weather conditions. This load shape is then scaled monthly to meet the peak and energy forecast.

It is expected that the increase in EV demand will have a significant impact on the load shape, which will likely have an impact on the timing and duration of system peaks, depending on the level of penetration and demand management that can be achieved. To capture this impact, the base load profile was escalated monthly to match the forecast load, excluding the forecast EV load. Following this, the hourly EV forecasted load was layered on top of the escalated load, to produce a load shape that accurately captures the impact of EV additions. As assumptions on EV penetration and demand management evolve, and/or federal targets change, the load shape will be continually assessed and updated appropriately.

5.1.2 Generation Modelling by Asset Class

To ensure accurate modelling of its supply resources, Hydro incorporated detailed modelling of its capacity resources and power purchase agreements, using probabilistic analyses.

[41] The CBPP CAA enables capacity assistance during the winter period (November 1 to April 30).The CBPP CAA also enables capacity assistance up to 50 MW during the summer period (May 1–October 31).
[42] During the 2023–2024 winter period the co-gen firm capacity was 6 MW, it is assumed to be 8 MW for future years.

The FOR is captured in the PLEXOS model by using a random outage profile for each of the runs of the Monte Carlo analysis. The FOR for each of the units was determined based on the Forced Outage Rate Methodology, provided as Attachment 1 to this Appendix. Maintenance was not considered in the assessment of long-term system reliability. Maintenance is generally scheduled in months with very low probability of loss of loads events (i.e., non-winter period), and typically would not be scheduled if analysis indicated a risk of loss of load.

5.1.2.1 Hydroelectric Generation

Most of the generators owned by Hydro are hydroelectric and therefore have limitations on the amount of energy available. The amount of storage varies widely depending on the reservoir capacity, unit capacity and expected inflows, from units having long-term storage adequate for several months of generation to units having storage capacities adequate for only a few hours of generation.

The units have been grouped into three categories for the purposes of modelling:

- Units with larger storage capacities;
- Units with smaller storage or Run-of-River units; and
- Units at Muskrat Falls.

5.1.2.1.1 Units with Larger Storage Capacities

Hydro units with larger storage capacities (i.e., Bay d'Espoir, Cat Arm, Hinds Lake, Exploits, Star Lake), and those that operate within large overall storage systems (i.e., Granite Canal and Upper Salmon), as well as Deer Lake Power are assumed to be able to generate at the plant-rated capacities in any given hour. Seasonal restrictions, particularly winter capacity restrictions, are modelled for the Exploits system as the facility is particularly susceptible to frazil icing. Other units on the system experience icing conditions, albeit much less frequently than Exploits generation. Hydro continues to monitor frazil icing events on all of its units and will make changes to its modelling assumptions as required.

5.1.2.1.2 Units with Smaller Storage/Run-of-River Units

For the smaller units with limited storage capacities (i.e., Paradise River), as well as Newfoundland Power's hydroelectric units, the energy limitation is modelled as a daily constraint. To model appropriately, these units were given a daily energy limit that varies by month. The daily energy limit is based on the monthly energy output of the Vista Model and historical data. Newfoundland Power's sites are modelled as 23 sites, 14 on the Avalon and 9 off the Avalon, with hydrology modelled in aggregate by region.

5.1.2.1.3 Muskrat Falls

Muskrat Falls has a winter firm plant total output of 824 MW (i.e., four units, each rated to 206 MW), based on rated head conditions. During certain river operating conditions, the plant will be able to produce more or less power than 824 MW. These operating conditions affect the water elevation at the water intakes to the units and the water outlet, or the tailwater, elevation. In the *RRA Study Review*, it was indicated that the winter plant output could be limited to 790 MW by tailrace icing based on simulated plant flows and tailwater rating curves.[43] Based on Hydro's operational experience with Muskrat Falls since commissioning, the predicted tailrace icing conditions have not been observed and the winter capacity constraint was removed in the model. Hydro will continue to monitor to determine if there are conditions under which tailrace icing may affect plant output and update the model accordingly in the future.

The characteristics of Muskrat Falls provides very little storage with which to regulate inflows. Approximately 75% of Muskrat Falls inflows are from releases from the Upper Churchill and 25% are local inflows to the Churchill River between Churchill Falls and Muskrat Falls. To capture the daily variability of generation, ten hourly hydrologic sequences were evaluated to provide a daily energy profile by month. This analysis was used to develop a statistical profile of the daily variations in generation at Muskrat Falls, with one of the ten profiles chosen at random for each of the stochastic runs.

Table 2 and Table 3 provide information on the capability of the hydroelectric generating fleet for the Island and the Labrador Interconnected Systems, respectfully. Only the firm capacity was included in the Reliability Model.

[43] A projected relationship between the tailwater level and water flow through the plant is referred to as the tailwater rating curve. A component of the river operating condition that can affect the tailwater rating curve is the winter ice cover in the river downstream of the plant, which can impact the plant output. When these estimated ice cover tailwater rating curves were applied to the plant production models, pre construction, the maximum plant output during the winter assumed restricted to 790 MW.

Table 2: Capacity of Island Interconnected System Hydraulic Generating Units (MW)

Unit	Installed Capacity	Firm Capacity
Bay d'Espoir		
Unit 1	76.5	76.5
Unit 2	76.5	76.5
Unit 3	76.5	76.5
Unit 4	76.5	76.5
Unit 5	76.5	76.5
Unit 6	76.5	76.5
Unit 7	154.4	154.4
Total Bay d'Espoir	**613.4**	**613.4**
Upper Salmon	84.0	84.0
Granite Canal	40.0	40.0
Cat Arm		
Unit 1	68.5	67.0
Unit 2	68.5	67.0
Total Cat Arm	**137.0**	**134.0**
Hinds Lake	75.0	75.0
Paradise River	8	8
Total Hydro-Owned Capacity	**957.4**	**954.4**
Other Hydraulic Generation		
Deer Lake Power	104.0	104.0
Newfoundland Power	94.2	60.1
Rattle Brook	4.0	0.0
Exploits	94.2	63.0
Star Lake	18.0	18.0
Total Other Hydraulic Capacity	**314.4**	**245.1**
Total Hydraulic Generation	**1,271.8**	**1,199.5**

Table 3: Capacity of Labrador Interconnected System Hydraulic Generating Units (MW)

Unit	Installed Capacity	Firm Capacity
Muskrat Falls		
Unit 1	206	206
Unit 2	206	206
Unit 3	206	206
Unit 4	206	206
Total Muskrat Falls[44]	**824**	**824**

1 #### 5.1.2.2 Thermal and CTs

2 In the Reliability Model, thermal units and CTs are modelled as generators with appropriate minimum
3 and maximum generation. No seasonal capacity or energy restrictions were placed on the thermal units
4 or CTs in the model. An hourly capacity restriction was placed on the Holyrood Diesels based on
5 environmental restrictions. Table 4 and Table 5 provide a summary of the existing thermal generating
6 units and subsequent installed and firm capacities that were modelled for the Island and Labrador
7 Interconnected System, respectfully.

[44] Quantity reported at Muskrat Falls.

Table 4: Island Interconnected System Existing Thermal Generating Units (MW)

	2024–2030[45]		Post 2030[46]	
Unit	**Installed Capacity**	**Firm Capacity**	**Installed Capacity**	**Firm Capacity**
Holyrood TGS				
Unit 1	170	170	N/A	N/A
Unit 2	170	170	N/A	N/A
Unit 3	150	150	N/A	N/A
Total Holyrood TGS	**490**	**490**	**N/A**	**N/A**
CTs				
Holyrood	123.5	123.5	123.5	123.5
Hardwoods	50	50	N/A	N/A
Stephenville	50	50	N/A	N/A
Total CTs	**223.5**	**223.5**	**123.5**	**123.5**
Diesels				
Hawkes Bay	5	5	5	5
Holyrood	12	8	12	8
St. Anthony	9.7	9.7	9.7	9.7
Total Diesel	**26.7**	**22.7**	**26.7**	**22.7**
Thermal (NP)	44.5	44.5	16.5	16.5
Total Thermal	**784.7**	**780.7**	**166.7**	**162.7**

Table 5: Labrador Interconnected System Existing Thermal Generating Units (MW)

	2024–2030		Post 2030	
Unit	**Installed Capacity**	**Firm Capacity**	**Installed Capacity**	**Firm Capacity**
Happy Valley GT	25	25	25	25
Total Thermal	**25**	**25**	**25**	**25**

1 A further discussion on asset retirement plans can be found in Section 5.1.6.

2 #### 5.1.2.3 Wind Generation

3 Hydro currently has PPAs with two interconnected wind farms[47] on the Island Interconnected System
4 with a combined capacity of 54 MW. Wind generation is an intermittent, non-dispatchable resource,

[45] The period 2024–2030 is referred to as the Bridging Period where new generation has not yet been added to the Island Interconnected System.
[46] Post 2030 it is assumed that Holyrood TGS, Hardwoods GT, and Stephenville GT are retired and new generation is added to the Island Interconnected System.
[47] Wind farms in Fermeuse (27 MW) and St. Lawrence (27 MW).

meaning its output cannot be easily varied like a conventional thermal resource as the output is dependent on the available wind speed. Production can also be challenging in times of very low or very high wind speeds. Low wind speeds may not reach the cut in speed required for the turbines to produce energy. Conversely, if wind speeds are too high, turbines may reach cut out speed, at which the turbines will shut down to prevent damage. In its 2018 Filing, Hydro included analysis of the contribution of wind generation to the reliability of its system to consider the effective contribution of wind generation to meet peak demand from a planning perspective.[48] This preliminary work was expanded through 2019 by conducting an ELCC study, a cumulative frequency analysis, and considered the impact of external factors including:

- Correlation and coincidence of existing and potential future sites;
- Seasonality of the wind resource at existing sites;
- Hourly generation profile at existing sites; and
- Existing and potential resource penetration.

The analysis was completed on the generation data from Fermeuse and St. Lawrence from in-service to 2019. The production data from these facilities implicitly includes the impacts of maintenance, forced outages, and unavailability due to both excessive and insufficient wind. From this data a probability distribution function was developed for each plant. To accurately model seasonal variations, a separate profile was developed for the winter season (i.e., December to March) and the non-winter season (i.e., April to November). For each run of the Monte Carlo analysis an hourly profile was randomly generated using the probability function. The ELCC study determined that the capacity contribution of the wind generation was 22% or approximately 6 MW of firm capacity per wind farm, which was included in the model and represented in Table 6.[49]

Table 6: Island Interconnected System Installed and Firm Capacity of Existing Wind Resources (MW)

Wind Resource	Installed Capacity	Firm Capacity
Fermeuse Wind Farm	27	6
St. Lawrence Wind Farm	27	6
Total Wind Generation	**54**	**12**

[48] "2018 Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, att. 6.
[49] "2019 Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, November 15, 2019, vol. I, att. 1.

Hydro continues to assume the capacity contribution of existing and incremental wind generation sources at 22% of the nameplate. However, this capacity contribution is heavily dependent on the location and penetration of wind generation. The ELCC study was based on a small penetration of wind farms. Hydro remains committed to further evaluation of the capacity contribution of wind as penetrations increase and the technology continues to evolve. The relationship between wind generation and the system will be assessed as part of ongoing resource planning efforts.

5.1.3 Capacity Transfers: Imports and Exports

Only firm imports and exports are considered as part of Hydro's modelling, consistent with NERC standard practice to ensure capacity is not double counted between jurisdictions.

5.1.3.1 Import Potential to the Island Interconnected System

When considering firm import of electricity across the Maritime Link to meet the reliability of the Newfoundland and Labrador Interconnected System, there are two main components to consider—firm transmission and firm capacity.

5.1.3.1.1 Transmission and Market Access[50]

The Island Interconnected System has access to three potential markets when considering firm imports via the Maritime Link—Nova Scotia, New Brunswick, and New England. A summary of these options from a transmission perspective follows:

1) **Nova Scotia**: To acquire energy from Nova Scotia, Hydro requires only its existing Maritime Link transmission access as Nova Scotia Power has the capability to deliver energy to the Nova Scotia-Newfoundland and Labrador border, resulting in the potential for less risk of curtailments.

2) **New Brunswick**: To acquire energy from New Brunswick, two transmission paths need to be considered—New Brunswick and Nova Scotia transmission.

    - The transmission path inside New Brunswick to deliver energy to Nova Scotia shares the interface between New Brunswick and Prince Edward Island. New Brunswick has firm contracts to supply firm energy and balance the load in Prince Edward Island. The

[50] Please refer to Hydro's response to NP-NLH-093 of the *RRA Study Review*.

transmission interface limit is 300 MW and the firm transmission is contracted by New Brunswick to meet their contractual obligations to Prince Edward Island.

- The interface between the New Brunswick/Nova Scotia transmission systems is often congested. In a February 2023 Integrated Resource Plan update from NS Power, it discussed firm imports on this interface:

> Update on potential Firm Imports from New Brunswick:
> - Firm import capacity from NB Power continues to be unavailable due to transmission system limits and committed firm exports to Prince Edward Island.
> - NS Power received confirmation from NB Power that the Reliability Tie, without additional transmission investment further into New Brunswick, is not anticipated to provide additional firm import capacity to Nova Scotia.[51]

3) **New England:** To acquire energy from the New England market, the two transmission paths across New Brunswick and Nova Scotia need to be considered, with the limitations noted previously. The export path from the New England market is limited by the New Brunswick/Nova Scotia interface. Additionally, the transmission interface between New Brunswick and the New England market can become congested. New Brunswick Power has priority at that interface for imports for their native load.

It is important to note that there are also Newfoundland transmission constraints in delivering imported energy via the Maritime Link.[52] These constraints are discussed further in Section 5.4.1.1.

5.1.3.1.2 Firm Capacity

In October 2023, Hydro confirmed with both NS Power and NB Power that acquiring a firm import contract during the winter period for reliability is not feasible for either utility in the near-term. However, the potential markets and constraints will continue to be assessed annually as part of the near-term generation adequacy filing. This confirmation does not preclude opportunities on a short-term (spot market) basis for firm capacity or non-firm energy to meet capacity or energy requirements

[51] "Integrated Resource Plan Action Plan Update – February 2023," Nova Scotia Power, February 2023, p. 10. https://www.nspower.ca/docs/default-source/irp/irp-action-plan-update-february-2023.pdf?sfvrsn=9684ec6f_1

[52] Please refer to "*Reliability and Resource Adequacy Study Review* – Avalon Supply (Transmission) Study," Newfoundland and Labrador Hydro, October 31, 2023.

for the Island Interconnected System, in consideration of available transmission paths and market access discussed previously.

Currently, there are no long-term firm import contracts in place, although there is a possibility that import contracts could become available at some point in the future. Non-firm imports are not considered in the reliability analysis. This is considered a prudent assumption for assessing the adequacy of provincial supply.

5.1.3.2 Import Potential to the Labrador Interconnected System

Currently Newfoundland and Labrador Hydro is unable to import power into the Labrador Interconnected System through the Hydro-Québec transmission path. The transmission transfer capability in the Hydro-Québec system to transfer energy from Hydro-Québec to Churchill Falls is zero.

5.1.3.3 Island Interconnected System Export Commitments

In the Reliability Model, firm exports are added as a load. The contractual requirements are used to derive an hourly profile for the exports.

There are two commitments for firm exports:

- The Nova Scotia Block: A commitment for firm energy of approximately 170 MW during peak hours;[53] and
- Supplemental Energy: A commitment for firm energy of an estimated 219 MW during winter off-peak hours.[54]

Delivery of the Nova Scotia Block commenced in August 2021, with the first physical delivery occurring on August 17, 2021.[55] Delivery of Supplemental Energy[56] commenced in November 2021, with the first physical delivery occurring on November 1, 2021. As per the Energy and Capacity Agreement, in instances where the LIL is fully unavailable, Hydro is not obligated to deliver the Nova Scotia Block or

[53] Pursuant to the Energy and Capacity Agreement between Nalcor and Emera, the Nova Scotia Block is a firm annual commitment of 986 GWh, supplied from Muskrat Falls on peak.
[54] Supplemental Energy is delivered to Emera in equal annual amounts over each of the first five years of operation of Muskrat Falls during the months of January to March and November to December during off-peak hours.
[55] Pursuant to the Energy and Capacity Agreement between Nalcor and Emera, the Nova Scotia Block is a firm annual commitment of 986 GWh, supplied from Muskrat Falls on peak.
[56] Supplemental Energy is delivered to Emera in equal annual amounts over each of the first five years of operation of Muskrat Falls during the months of January to March and November to December during off-peak hours.

Supplemental Energy in the hours of unavailability. In these instances, Nova Scotia will experience a loss of deliveries on their system, which would make it difficult for them to supply their own additional needs as well as support the Island Interconnected System requirements.

5.1.3.4 Export Potential via the Labrador-Hydro-Québec Transmission Path

Hydro has the ability to export surplus (excluding the long-term sales contract with Hydro-Québec) power from the Churchill Falls Recapture Block[57] of energy through Québec. Hydro holds 265 MW of firm transmission rights with rollover rights in the Hydro-Québec Transmission System allowing Hydro to wheel 265 MW of energy year-round to the New York, New England, and Ontario wholesale energy markets and can also provide access to New Brunswick and Nova Scotia markets (by wheeling through New Brunswick). In addition to the 265 MW of firm transmission, Hydro has the ability to purchase non-firm transmission through the Hydro-Québec Transmission System to the same markets. Exports from Labrador through Hydro-Québec are currently limited to 300 MW.

Muskrat Falls and Hydro entered into a PPA for the purchase and sale of Residual Block Energy. Under this agreement, Labrador Rural and Industrial customer load, previously serviced with Recapture Energy from Churchill Falls, is now serviced with energy from Muskrat Falls. Entering into this agreement has allowed additional Recapture Energy exports to external markets helping to ensure maximum value from the organization's hydrological resources.

5.1.4 Transmission System

Hydro's Reliability Model includes a simplified representation of the transmission system to ensure the system can deliver electricity to meet customer requirements and that all relevant constraints are appropriately considered as part of the resource planning process. Hydro's Reliability Model separates the Newfoundland and Labrador Interconnected System into two regions linked by transmission—the Island Interconnected System region and the Labrador Interconnected System region—with the LIL connecting the two. These regions are further divided into sub-regions (e.g., On-Avalon, Off-Avalon, Labrador West, and Labrador East) linked by the transmission network for the purposes of calculating losses. There are also two external regions modelled, representing the two connections to external

[57] Recapture Block is 300 MW of capacity with a monthly energy capacity factor of 90%; historically, this block of energy primarily serves Hydro load in Labrador with the surplus energy being exported by Nalcor Energy Marketing.

markets via Québec and Nova Scotia. The transfer capability of each transmission line is included in the Reliability Model.

In the Labrador Interconnected System, there are transmission constraints on the radial feeds to the eastern and western regions.[58] Consideration of these transmission constraints is beyond the scope of this analysis.

Figure 4 is a representation of the Newfoundland and Labrador Interconnected System. It is a simplified display of how each region is electrically connected within the provincial zone and to the external markets in Québec and Nova Scotia, with arrows indicating the flow of energy.

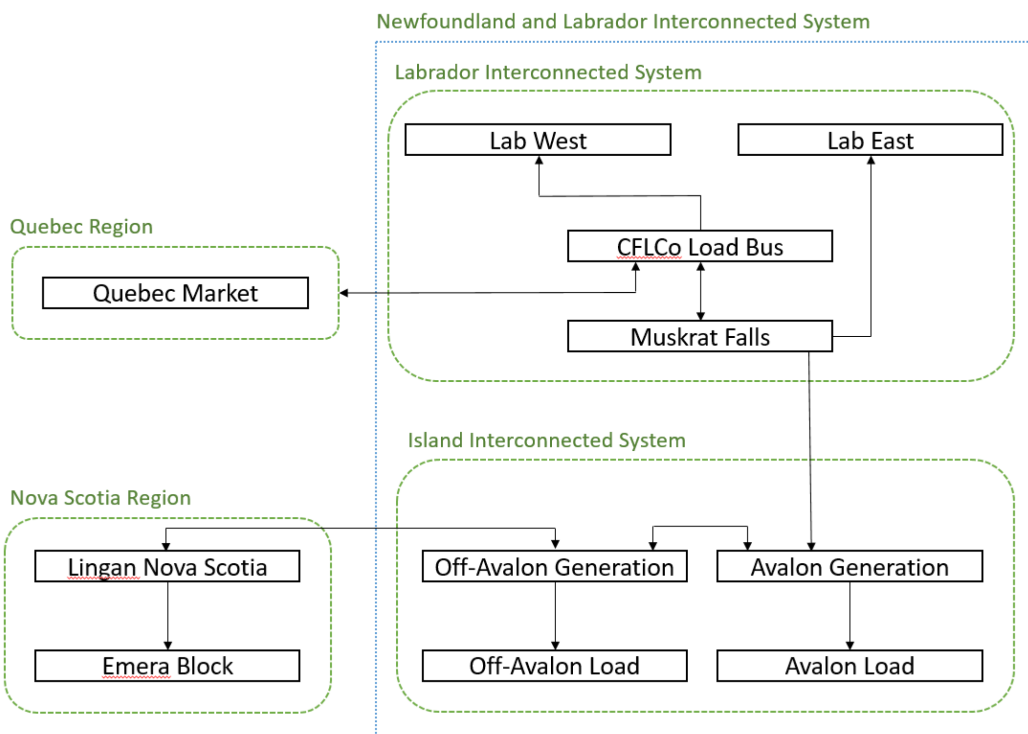


Figure 4: Newfoundland and Labrador Model Topography

5.1.4.1 The LIL

With the addition of Muskrat Falls, a large portion of the generation serving the Island load is located in Labrador. Therefore, the reliability of the LIL is a key driver of Island Interconnected System reliability.

[58] In the current transmission system, a maximum of 385 MW can be delivered to Labrador West and a maximum of 104 MW can be delivered to Labrador East.

Throughout its early operation, the LIL has had periods of unavailability due to structural, equipment, and software issues.[59] To account for this uncertainty the reliability of the LIL continues to be modelled in three ways:

- Probabilistic assessment of LIL reliability;
- LIL as an energy-only line; and
- Extended outage of the LIL (LIL Shortfall Assessment).

Until Hydro accrues multiple years of LIL post-commissioning operational experience to better inform the selection of a single representative LIL bipole EqFOR, a range of LIL bipole EqFORs have been considered. Since commissioning, LIL performance has been calculated using LIL bipole EqFOR.[60,61] A Planning Reserve Margin estimate has been developed to correspond with each LIL bipole EqFOR to assess the level of future system expansion that would be required. The LIL performance statistics are tracked so that the LIL bipole EqFOR range can be narrowed in future filings. Since commissioning, the LIL bipole EqFOR was calculated to be approximately 2.34% on the base LIL capacity of 700 MW.[62]

As the LIL has been commissioned and tested up to 700 MW, this capacity was used as the baseline throughout the analysis. Variations in LIL capacity between 700 MW and 900 MW do not have a material impact on the Planning Reserve Margin; rather, it is the LIL bipole EqFOR that remains the key driver. In the winter months, Muskrat Falls generation is limited between 600 MW and 660 MW continuous generation, therefore a LIL capacity of 700 MW allows for use of that generation with a limited ability to shape the generation to meet load requirements. The spring freshet period is typically the only time of year when generation is able to be maximized continuously at Muskrat Falls. However, because the Island Interconnected System load is typically lower in the spring compared to the winter period and due to the LIL and Maritime Link operational relationship, the benefit of additional LIL deliveries would

---

[59] Please refer to "*Reliability and Resource Adequacy Study Review* – Labrador-Island Link Update for the Quarter Ended June 30, 2024," Newfoundland and Labrador Hydro, July 4, 2024, for Hydro's most recent update.
[60] The LIL bipole EqFOR measures the percentage of time that the LIL bipole is unable to deliver its maximum continuous rating to the Island due to bipole forced outages, bipole derates, derates due to unplanned monopole outages, or derates due to overlapping monopole outages (effectively creating a bipole outage). Please refer to Section 3.1 of Attachment 1 to this Appendix for additional information on LIL bipole EqFOR.
[61] Hydro previously used "bipole forced outage rate" in reference to the LIL; this was changed in January 2024 to "LIL bipole EqFOR."
[62] From April 1, 2023 to June 1, 2024.

be related to additional exports over the Maritime Link versus additional deliveries to the Island Interconnected System. Further discussion on this relationship is included later in this section.

LIL reliability was modelled probabilistically using a LIL bipole EqFOR range of 1% to 10% (full link), as well as a scenario in which the LIL is not assumed to provide any reliability benefit (i.e., it is considered to be an energy-only line). The LIL bipole EqFOR of 5% was selected for the Reference Case, or Expected Case, Expansion Plan scenario.[63]

Table 7 summarizes the LIL capacity and equivalent LIL bipole EqFOR scenarios considered in this analysis.

Table 7: LIL Capacity and Bipole EqFORs[64]

LIL Capacity (MW)	LIL Bipole EqFOR (%)
700	1
700	5
700	10
Energy-Only Line	100[65]

Lastly, a probabilistic scenario where the LIL is unavailable for six weeks was modelled to quantify the resultant system reliability and identify the costs associated with providing incremental generation to reduce loss of load probability. The methodology behind this analysis is discussed further in the following section.

5.1.4.2 LIL Shortfall Assessment

The LIL Shortfall analysis models a deterministic scenario where the LIL is unavailable for up to six weeks in the coldest part of the winter (i.e., January 1–February 15) to quantify the resultant system reliability. The analysis was completed using the Reliability Model by removing the availability of the LIL to flow energy to the Island Interconnected System for that period, as well as removing Nova Scotia Block deliveries over the Maritime Link.

[63] Please refer to Section 6.0 of Appendix C.
[64] For reference, a LIL bipole EqFOR of 1% equates to approximately 4 days per year when the LIL is unavailable; a LIL bipole EqFOR of 5% represents approximately 18 days per year; a LIL bipole EqFOR of 10% represents approximately 37 days per year of unavailability.
[65] A LIL bipole EqFOR of 100% represents modellig the LIL as an Energy-Only line.

During the six-week period, Hydro anticipates being able to call on CBPP capacity assistance for 50 MW for an extended duration. This is a conservative approach as there may be periods where CBPP can deliver up to 90 MW when called upon.

Vale customer generation was input as a reduced capacity from 7.5 MW to 5.5 MW based on continuous rating of the units.

5.1.4.3 Relationship between the LIL and the Maritime Link

The LIL and the Maritime Link are equipped with runbacks—LIL Power Demand Override and Maritime Link Emergency Power Control—to provide frequency regulation in the event of pole and bipole contingencies on either link. Consequently, flows on the LIL and the Maritime Link must be coordinated. Therefore, under normal system conditions, the amount of energy that can flow over the LIL to the Island is limited by the interdependencies with the Maritime Link and Island load. This interdependence exists because both HVdc links must work together using RAS that will suddenly reduce their power flows (runbacks) to transiently regulate system frequency in the event a contingency occurs on the other HVdc link.

This LIL-Maritime Link relationship does have an impact on the amount of power that can be absorbed on the Island (Net dc)[66] but, is primarily dependant on the amount of UFLS that is available and would be triggered following a LIL bipole trip. The amount of available UFLS is directly proportional to the total Island load. In the event of a LIL bipole trip and a subsequent Maritime Link runback, the Island system would experience a loss of supply at a magnitude of the Net dc. The only mechanism to transiently offset this loss of supply would be UFLS. Therefore the higher the amount of armed UFLS the more energy that can be sunk on the Island Interconnected System. Hydro is currently performing power system studies to confirm the maximum allowable UFLS following a LIL bipole trip. For ease of reference, this will be referred to as the LIL-Maritime Link relationship going forward.

Due to the LIL–Maritime Link relationship, an hourly capacity profile for the LIL was developed, based on the hourly Island load profile and the firm contractual export commitments over the Maritime Link. The hourly capacity profile was incorporated into the model as an additional constraint on the LIL flow. The delivery capability of the LIL increases as island load increases and in high load hours, the LIL is generally

[66] The difference between the amount of LIL Imports delivered at Soldiers Pond and Maritime Link Exports at Bottom Brook.

available at or near its peak capacity of 700 MW. As this relationship enables LIL deliveries up to peak capacity in high load hours (i.e., the winter period), the LIL-Maritime Link relationship has minimal impact on Island Interconnected System reliability. However, this relationship does have a significant impact on the amount of firm energy that can be delivered to the Island in low load hours (i.e., non-winter period), with the highest impact in the summer months, resulting in an annual restriction on the amount of firm energy available to the Island Interconnected System. The impact is discussed further in Section 5.3.1.4.

5.1.5 Minimum Regulating Reserve

Hydro has implemented a minimum regulating reserve in its Reliability Model for the Island Interconnected System. Unlike other reserves that are used in response to contingencies (i.e., operating reserves), regulating reserves are used throughout an operating hour to maintain system frequency in response to fluctuations in loads and output from variable generation resources. It was previously determined that the amount of such regulating reserve required to be held on the system differs based on whether the LIL is in service due to the LIL's frequency control capability. When the LIL is in service, the system requires a lower minimum regulating reserve, as the LIL can provide frequency regulation. In the 2019 Update, Hydro preliminarily defined a minimum regulating reserve of 35 MW for when the LIL was in service while maintaining a minimum reserve of 70 MW within the Island Interconnected System when the LIL is on a bipole outage to provide acceptable frequency regulation. Given the continued uncertainty pertaining to LIL reliability, Hydro believes it to be prudent to maintain a minimum regulating reserve of 70 MW within the Island Interconnected System, whether or not the LIL is in service. This is subject to further review once operational experience is gained with the LIL.

5.1.6 Planned Generation Retirements

As identified in the 2022 Update, there is a need to maintain aging assets on the Island Interconnected System until the LIL is proven reliable and new generation can be approved, and constructed. This timeframe is referred to as the "Bridging Period" and was tentatively selected to be the period between 2023 and 2030. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. Hydro's current plan is to retire the Holyrood TGS and the Hardwoods GT in 2030.

The analysis completed for the 2022 Update supported the retirement of the Stephenville GT by March 31, 2024, at which point the backup supply for the area served by the Stephenville GT was planned to be addressed by the addition of a 230/66 kV, 40/53.3/66.7 MVA power transformer at the Bottom Brook Terminal Station and subsequent reconfiguration at the Stephenville Terminal Station, which commenced in 2021. This addition will provide capacity via the 66 kV network in the event of the loss of the existing 230/66 kV Transformer T3 at the Stephenville TS or the loss of 230 kV TL209.[67] In light of a combination of increased load growth, an increase in hydro generation FORs, the forced unavailability of Unit 2 at the Holyrood TGS during the 2023–2024 winter operating season and the risks of aging asset availability, Hydro is continuing operation of the Stephenville GT beyond 2024. At this time, it is assumed the facility will retire in 2030, the same year as both Holyrood TGS and Hardwoods GT; however, Hydro will continue to review near-term reliability in combination with the timeline to construct new assets and update the model accordingly. Hydro will finalize its decision in 2024 to cancel most of the remaining scope of this transmission project due to the extension of Stephenville GT. If any of the cancelled scope is deemed to be required in future years, it will be included in a future capital budget application.

There will likely be some overlap between the Bridging Period and the Future Period while the existing thermal generation is retired and new generation is brought into service; however, this overlap has not been included in the modelling methodology for this filing. As new capacity is added and deemed reliable, existing thermal generation can be retired, while closely monitoring system reliability in the interim to also ensure that Muskrat Falls and the LIL are reliable before proceeding with On-Island retirements. Going forward, the Bridging Period timeframe will be assessed in the annual Near-Term Generation Adequacy filings.

Since 2022, Newfoundland Power's corporate plan has included the retirements of both its Greenhill and Wesleyville GTs, as they are nearing the end of their planned service lives with no plans for refurbishment. The capacity of the Greenhill GT is 20 MW and the Wesleyville GT is 8 MW, totalling 28 MW of capacity that has been removed from the supply forecast and Hydro's Reliability Model beyond an assumed date of 2030. A list of unit retirements are provided in Table 8.

[67] A project to complete these modifications was included in the "2021 Capital Budget Application," Newfoundland and Labrador Hydro, rev. 2, November 2, 2020 (originally filed August 4, 2020), vol. II, tab 14.

Table 8: Planned Generation Retirements

Unit	Retirement Date	Firm Capacity (MW)
Holyrood TGS	April 1, 2030	490
Hardwoods GT	April 1, 2030	50
Stephenville GT	April 1, 2030	50
Greenhill GT (NP)	2030	20
Wesleyville GT (NP)	2030	8

As part of its Transmission Planning Annual Assessment process, Hydro has been working with Newfoundland Power to review the provincial system and identify potential violations of Transmission Planning Criteria. In recent discussions, Newfoundland Power has identified that the addition of 25 MW CTs could provide effective solutions to potentially resolve future violations. Specifically, consideration is being given to the installation of generators to replace existing thermal assets in Wesleyville, Greenhill, and the Port-aux-Basques region. While the justification of these additions based on regional transmission reliability consideration is beyond the scope of the *RRA Study Review*, Hydro is continuing to work with Newfoundland Power to explore these solutions and to understand how this potential capacity could be used to support future load growth. This is discussed further in the 2024 Expansion Plans.[68]

For generation purchased under a PPA, the generation is assumed to be available until the end of the contract period. However, this does not suggest there isn't the potential for a mutually beneficial extension of any PPA that is due to expire within the planning horizon (2024–2034). Hydro will continue to work closely with PPA counterparties to determine options going forward. A list of PPAs that are due to expire within the planning horizon is provided in Table 9.

[68] Please refer to Section 6.2.1.1 of Appendix C.

Table 9: PPA Expiration Dates

PPA	Expiry Date	Firm Capacity (MW)
New World Dairies	April 14, 2024	0
Rattle Brook	April 30, 2026	0
St. Lawrence Wind	May 31, 2029	6
Fermeuse Wind	June 30, 2029	6
CBPP Co-Gen	2034	8

There are currently no planned retirements for the Labrador Interconnected System in the study period.

5.1.7 Planning Reserve Margin Requirements

To quantify the impact of planning to a more stringent planning criteria of 0.1 LOLE versus the existing planning criteria of 2.8 LOLH, as well as the impact the LIL bipole EqFOR has on Island Interconnected System reliability, Hydro calculated multiple planning reserve margins that were input into the Expansion Model for different scenarios. Figure 4 and Table 10 depict the Planning Reserve Margin requirements in terms of megawatt and the percent of peak in the representative year (2032) for various combinations of LIL FOR and planning criteria. Note that the LIL bipole EqFOR of 100% refers to the scenario conducted that considers the LIL as an energy-only line.

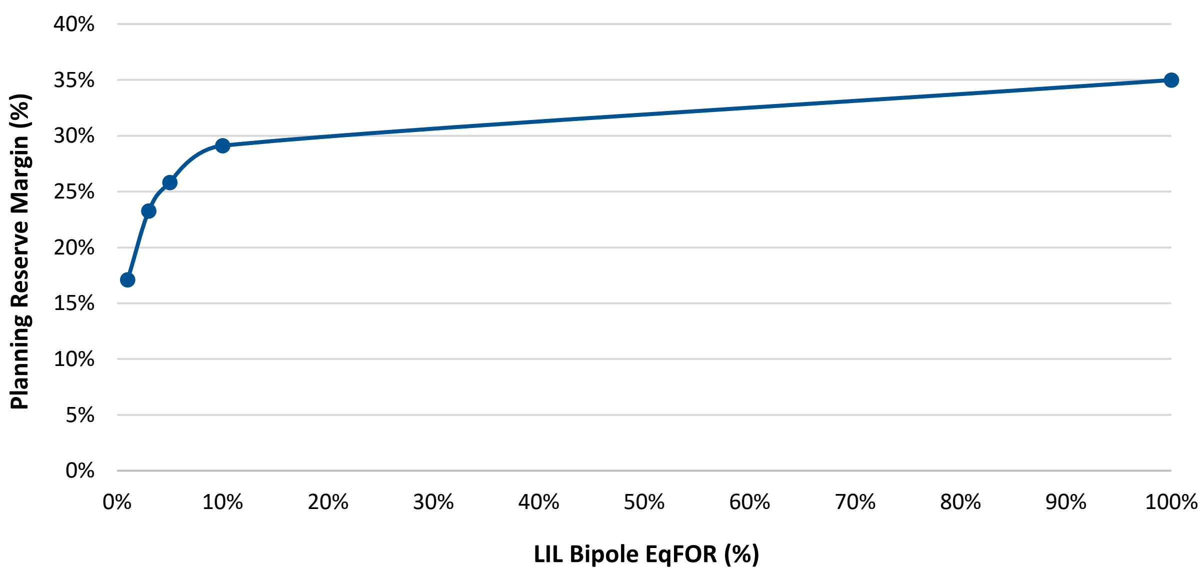


Figure 5: 2.8 LOLH Reserve Margin versus LIL Bipole EqFOR

Table 10: Planning Reserve Margin Requirements

Planning Criteria	LIL Bipole EqFOR (%)	2032 Reserve Margin (MW)	Reserve Margin (% of Peak)
2.8 LOLH	1	360	17.1
2.8 LOLH	3[69]	460	23.3
2.8 LOLH	5	500	25.8
2.8 LOLH	10	550	29.1
2.8 LOLH	Energy-Only Line	675	35.0
0.1 LOLE	5	635	35.1

Three key observations can be made from this analysis:

1) **The migration to a system reserve margin that satisfies LOLE ≤ 0.1 requires substantially higher reserves.**

As outlined in Table 11, assuming a LIL bipole EqFOR of 5%, an additional 135 MW of reserves is required to meet the more stringent planning criteria of LOLE ≤ 0.1. Further discussion on the cost associated with the increased level of reserves to meet LOLE ≤ 0.1 can be found in the 2024 Expansion Plans.[70]

Table 11: Difference between Planning Criteria versus Reserve Margin Requirements

LIL Bipole EqFOR (%)	Planning Reserve Margin Requirement (MW)		Delta (MW)
	2.8 LOLH	0.1 LOLE	
5	500	635	135

2) **The LIL Bipole EqFOR assumptions have a material impact on reserve margin requirements.**

For the range of LIL bipole EqFOR assumptions currently evaluated, the Planning Reserve Margin requirements that satisfy a 2.8 LOLH range from 360 MW (LIL bipole EqFOR of 1%) to 550 MW (LIL bipole EqFOR of 10%), for a total difference in potential requirements of approximately 200 MW, depending on LIL reliability. Should the LIL not be counted on for capacity, a Planning Reserve Margin of 675 MW is required.

3) **The relationship between LIL reliability and system reliability is not linear.**

[69] Please note that the LIL bipole EqFOR of 3% was calculated for information purposes only to inform the shape of the plot in Figure 5. The Expansion Plan analysis was not conducted using the calculated reserve margin of 23.3%.
[70] Please refer to Section 6.3.1 of Appendix C.

From a probabilistic capacity criterion perspective, it is important to note that the relationship between the LIL bipole EqFOR and the Planning Reserve Margin is not linear, which is evident in Figure 5. Observing the 2.8 LOLH probabilistic planning requirements, the difference in Planning Reserve Margin requirements between a highly reliable LIL (LIL bipole EqFOR of 1%), compared to the expected case (LIL bipole EqFOR of 5%) is approximately 145 MW. Subsequently, the difference between the Planning Reserve Margin requirements of the expected case (LIL bipole EqFOR of 5%), compared to the high case (LIL bipole EqFOR of 10%), is only 50 MW.

Because the LIL bipole EqFOR of 5% was selected for the Reference Case or Expected Case, Expansion Plan scenario, adopting a Planning Reserve Margin of 25.8%, or 500 MW, is required to meet this scenario. The proposed Planning Reserve Margin has decreased by 10% compared to the 2022 Update, primarily due to the change in planning criteria from LOLE ≤ 0.1 to 2.8 LOLH. For comparison, the Planning Reserve Margin to meet LOLE ≤ 0.1 is 35%, requiring an additional 135 MW of Planning Reserve Margin requirements. Hydro is not recommending to meet planning criteria of LOLE ≤ 0.1 at this time in consideration of the balance between cost and reliability.

5.2 Operational Reserve Requirements

As detailed in Section 3.5, Table 12 presents operational reserves required to be available.

Table 12: Island Interconnected System Operational Reserve Requirements Results (MW)

Reserve	Operational Reserve Required
10-Minute Reserves	206
30-Minute Reserves	103
Total	**309**

In the Newfoundland and Labrador Interconnected System, Hydro considers the first contingency loss to be the loss of a generating unit at Muskrat Falls and the second contingency loss to be the loss of a second unit at Muskrat Falls. As such, Hydro will plan for the availability of the following operational reserves for the Newfoundland and Labrador Interconnected System to align with these criteria.[71] These criteria are considered independent of the probabilistic capacity criteria.

[71] This is based on the per unit contribution to the firm plant output of Muskrat Falls (824 MW).

5.3 Firm Energy Model Methodology

The current energy criteria requires the Island and Labrador Interconnected Systems to have sufficient generating capability to supply all its firm energy requirements with firm system capability. In the 2022 Update, the Island and Labrador loads were combined and compared against the total provincial load[72] for the Newfoundland and Labrador Interconnected System. As introduced in Section 3.1 and discussed in detail in Section 5.1.4.3, it is now confirmed that the amount of energy that can flow over the LIL to the Island is limited by the interdependencies with the Maritime Link and Island load. This interdependence exists because both HVdc links must work together using RASs that will suddenly reduce their power flows (runbacks) to transiently regulate system frequency in the event a contingency occurs on the other HVdc link, resulting in the further requirement to consider the firm energy requirement of the two regions independently. Therefore, for this filing, the Island and Labrador Interconnected Systems have been assessed separately, with the LIL considered as a firm energy resource to the Island. The results of the firm energy analysis were used as input into the Expansion Model to produce Island Interconnected System Expansion Plans that satisfy both capacity and energy requirements and can be found in the 2024 Expansion Plans.[73]

In 2023, Hydro engaged Daymark to review the firm energy methodology, which is summarized in the memo provided as Attachment 2 to this Appendix. Daymark confirmed that Hydro's analysis was "technically sound and comports with industry-standard planning practices," and recommended that in the future Hydro begin co-optimizing the firm energy and capacity resources utilizing the PLEXOS expansion model tool.

The following sections summarize the firm energy resources available on the Island and Labrador Interconnected Systems, respectively. For this analysis, each unit on the system is assigned a firm energy. The methodology for assigning firm energy to each class of units is described in the subsequent sections. This analysis is completed in a spreadsheet and is a deterministic comparison of the available firm energy to meet the load requirements.

---

[72] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, att. 5.
[73] Please refer to Section 6.0 of Appendix C.

5.3.1 Island Interconnected System

5.3.1.1 Hydro

The firm capability of Island hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. This is considered as the critical dry sequence and it occurred between 1959 and 1962.[74] Table 13 provides a summary of the average and firm energy of the Island Interconnected System's hydraulic resources; however, only firm energy was used for modelling firm energy requirements.

Table 13: Energy Capability of Modelled Island Hydraulic Facilities (GWh)

Hydraulic Facilities	Average	Firm
Hydro-Owned		
Bay d'Espoir	2,650	2,096
Upper Salmon	556	317
Granite Canal	246	188
Hinds Lake	354	290
Cat Arm	755	678
Paradise River	35	33
Total Hydro-Owned	**4,596**	**3,602**
Other Hydraulic Generation		
Newfoundland Power	430	324
Deer Lake Power	750	750
CBPP Co-Gen	52	52
Exploits	635	547
Star Lake	144	87
Total Other Hydraulic Generation	**2,011**	**1,760**
Total Hydraulic Generation	**6,607**	**5,362**

Newfoundland Power has both hydro and thermal resources on the Island. No firm energy is assumed from Newfoundland Power's thermal assets following the same rationale for excluding Hydro's standby generation resources from the analysis.

[74] Minimum storage targets are developed for the Island Interconnected System annually to provide guidance in the reliable operation of Hydro's major reservoirs: Victoria, Meelpaeg, Long Pond, Cat Arm, and Hinds Lake. The minimum storage target is designed to show the minimum level of aggregate storage required such that if there was a repeat of Hydro's critical dry sequence, or other less severe sequence, Hydro's load can still be met through the use of the available hydraulic storage, maximum generation at the Holyrood TGS, and imports. Hydro's long-term critical dry sequence is defined as January 1959 to March 1962 (39 months). Other dry periods are also examined during the derivation to ensure that no other shorter-term historic dry sequence could result in insufficient storage.

Kruger Inc. owns the Deer Lake Power Hydroelectric Power Plant, which supplies power to CBPP. The firm energy assumption used in this analysis matches the estimated demand from CBPP which is included in the Island Interconnected load forecast. In other words, it is assumed that this facility self-supplies all its load, and Hydro does not have an obligation to provide energy to CBPP in the case of a low inflow year.

The CBPP Co-Gen PPA agreed to a ten-year term for both firm and non-firm power from the 15 MW co-gen plant at CBPP and/or hydraulic sources.

Exploits (Grand Falls, Bishop's Falls, and Star Lake) hydroelectric facilities are owned by GNL. Hydro has a contract with the province to operate and purchase all of the energy from these facilities.

5.3.1.2 Wind

The St. Lawrence and Fermeuse wind farms provide energy to Hydro through PPAs which are due to expire in 2029, corresponding to their estimated end of life. While Hydro intends to work with the owners to assess whether there would be an opportunity to extend the life of these facilities, for this study it is assumed there is no energy from these facilities beyond 2029. Hydro has used the average generation (as opposed to firm generation) from the most recent four-year period (2020–2023) for the firm energy analysis. This was deemed an appropriate assumption as it avoids layering contingencies between hydro facilities and wind facilities that are not proven to exist (i.e., pairing a critical low wind year with a critical low water year). Table 14 provides a summary of the average and firm energy of the Island Interconnected System's wind resources; however, only average energy was used for modelling firm energy requirements.

Table 14: Energy Capability of Modelled Island Wind Resources (GWh)

Wind Generation	Average	Firm
St. Lawrence	99	92
Fermeuse	80	75
Total Wind Generation	**179**	**167**

5.3.1.3 Thermal

Firm capability for the Holyrood TGS (which is operated as a baseload facility) is based on energy capability, adjusted for planned maintenance and forced outages. This generation station is assumed to be retired in 2030.

Consistent with the previous methodology, Hydro has not assumed any firm energy from other thermal resources (i.e., standby generation) on the Island since they are operated as peaking plants and their capacity to provide significant amounts of energy is limited. Table 15 provides a summary of the firm energy of the Island Interconnected System's thermal resources; however, only contributions from Holyrood TGS were included until April 1, 2030 for modelling firm energy requirements.

Table 15: Firm Energy from Thermal Resources (GWh)

Thermal Generation	Firm
Holyrood TGS	2,996
Holyrood CT	0
Hardwoods GT	0
Stephenville GT	0
Total Thermal Generation	**2,996**

5.3.1.4 Transmission

During normal operation, energy that can be brought from Muskrat Falls via the LIL is defined by the interdependencies with the Maritime Link and Island load, primarily driven by the amount of UFLS that is available to protect the system against a LIL bipole trip and by the amount the Maritime Link can runback for frequency response. As a result, how the LIL and the Maritime Link are modelled are discussed in the Sections 5.3.1.4.1.1 and 5.3.1.4.1.2.

5.3.1.4.1 The Maritime Link

The firm export requirements and potential for imports over the Maritime Link are modelled as follows.

5.3.1.4.1.1 Export Requirements

Hydro has an annual firm energy commitment to supply Nova Scotia with approximately 986 GWh annually via contractual deliveries for the Nova Scotia Block. The Supplemental Energy commitment is due to end in 2026.

5.3.1.4.1.2 Import Potential

As discussed in Section 5.3.1.1, there are currently no long-term firm contracts in place, although there is a possibility that import contracts could become available at some point in the future. A summary of the firm energy potential follows:[75]

- **Nova Scotia**: According to the 2023 Evergreen Integrated Resource Plan,[76] NS Power continues to plan to retire coal by 2030 and does not have surplus capacity in their system to export. NS Power heavily relies on coal to meet their capacity requirements in the winter and is looking to replace its coal plants with total capacity of 1,081 MW by 2030 to meet federal government regulations.
- **New Brunswick**: NB Power filed a ten-year Integrated Resource Plan in 2023,[77] at which time it outlined the requirement to build additional capacity builds to meet load growth and decarbonization plans. This past winter, New Brunswick also reached an all-time peak demand, which could further reduce near-term surplus capacity.
- **New England**: The market in New England has an annual forward capacity market auction. Each auction determines the capacity market for the fourth year out in the future. Considering the long lead time to build the required capacity in Newfoundland and Labrador, an annual auction four years in advance is insufficient to plan for the long-term reliability of the Island Interconnected System.

Non-firm imports over the Maritime Link are not included in the firm energy analysis.

5.3.1.4.2 The LIL

As discussed in detail in Section 5.1.4.3, the firm energy available to be delivered over the LIL, the LIL-Maritime Link relationship was applied for each hour of the planning horizon. Inputs included hourly Island load, minimum contracted Maritime Link exports (i.e., the Nova Scotia Block and Supplemental Energy), the minimum generation level for Island generating assets, transmission losses, and a range of

[75] Please refer to Hydro's response to NP-NLH-093 of the *RRA Study Review*.
[76] "Powering A Green Nova Scotia, Together – 2023 Evergreen Integrated Resource Plan – Updated Action Plan and Roadmap," Nova Scotia Power Inc., August 8, 2023. https://www.nspower.ca/docs/default-source/irp/2023-action-plan-and-road-map.pdf?sfvrsn=bcd3c747_1
[77] "2023 Integrated Resource Plan – Pathways to a Net-Zero Electricity System," New Brunswick Power Corporation. https://www.nbpower.com/media/1492536/2023_irp.pdf

assumed LIL bipole EqFORs. The current capacity of the LIL in bipole operation (700 MW) was used in the analysis.

Figure 6 illustrates the annual energy from the LIL available to serve load on the Island (i.e., total LIL flow minus Maritime Link contractual commitments) under the three Island Interconnected System load forecast scenarios that were outlined in Section 5.1.1. The available LIL energy to the Island Interconnected System increases each year associated with increasing Island load. The reduced slope from 2027 onward correspond to a reduction in Maritime Link exports. The Supplemental Energy contract is a commitment to deliver additional energy to Nova Scotia in the period from November to March and terminates in March 2026.

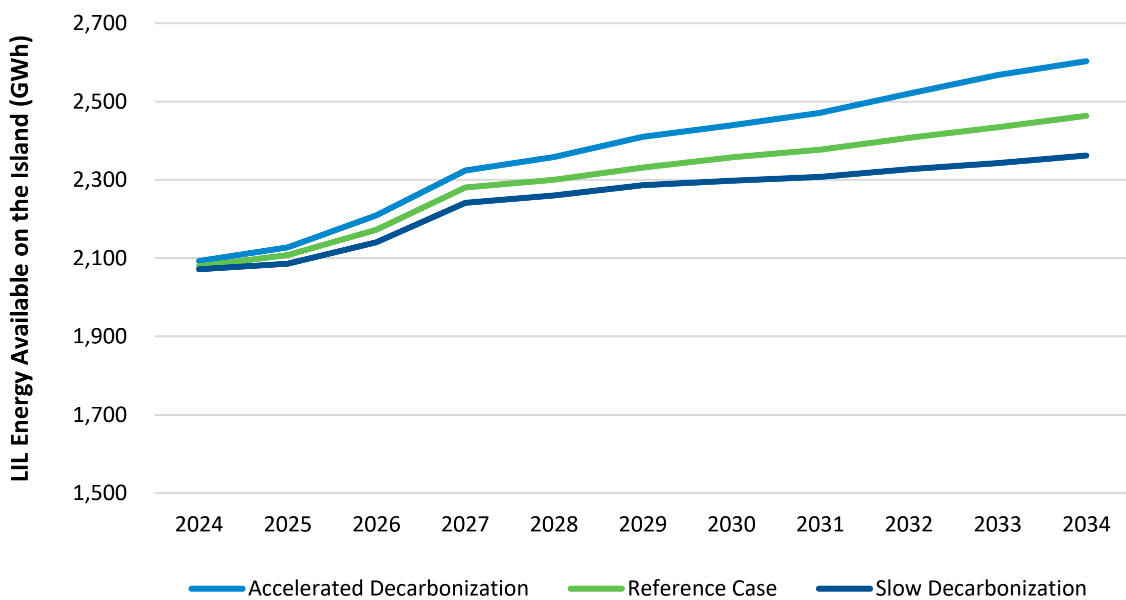


Figure 6: Annual Energy Available on the Island from the LIL

The average expected annual generation from Muskrat Falls is 4.9 TWh,[78] which varies from the firm energy estimate of 4.5 TWh. The characteristics of Muskrat Falls provides very little storage with which to regulate inflows. Approximately 75% of Muskrat Falls inflows are from releases from the Upper Churchill and 25% are local inflows to the Churchill River between Churchill Falls and Muskrat Falls. In 2013, an analysis was undertaken to assess the travel time and degree of attenuation of outflows from

[78] Results of long-term monthly modelling of the Muskrat Falls reservoir in Vista was used to derive the average annual energy expected from Muskrat Falls.

Churchill Falls to Muskrat Falls and the degree to which Muskrat Falls generation could be shaped within the day. The modelling provided some indication of how the daily generation could vary by hour. Five hourly hydrologic sequences were evaluated for a one-year period. The results of this analysis were used to determine the day-to-day variation in Muskrat Falls generation from the monthly mean. The monthly mean was calculated for each day in the five-year study period; from this, the daily variation from the mean was calculated. This was used to develop a statistical profile of the daily variations in generation at Muskrat Falls. The potential for variability across potential inflow scenarios is incorporated by modelling the energy limitation of the Muskrat Falls plant probabilistically. This approach allows the model to consider both the daily and seasonal variations in flow, including low inflow periods. However the determining factor for Muskrat Falls generation that can be delivered to the Island is the LIL-Maritime Link relationship that was previously discussed, not Muskrat Falls hydrology.

Treating the Island Interconnected System as a separate region from a firm energy perspective will help to ensure reliability. The results of the Island Interconnected System firm energy analysis can be found in the 2024 Expansions Plans.[79]

5.3.2 Labrador Interconnected System

The Labrador Interconnected System is characterized by supply at Churchill Falls, and transmission to the two major load centres in Labrador East and Labrador West. The supply at Churchill Falls is provided by two sources; the TwinCo Block and Recapture Energy. The TwinCo Block is a firm 225 MW block of power and energy, capable of supplying 1,971 GWh per year for use in Labrador West.[80] The Recapture Energy is a source of 300 MW of capacity at a 90 percent monthly load factor available at a defined point near the Québec to Labrador border.

Similar to the thermal resources on the Island, no firm energy has been assumed for the Happy Valley GT.

As mentioned previously, the LIL is considered a firm energy resource to the Island and correspondingly a firm energy export from Labrador to the Island Interconnected System. This means that Muskrat Falls

[79] Please refer to Section 3.1 of Appendix C.

[80] Muskrat Falls and Hydro entered into a PPA for the purchase and sale of Residual Block energy. Under this agreement, Labrador Rural and Industrial customer load, previously serviced with Recapture Energy from Churchill Falls, is now serviced with energy from Muskrat Falls. Entering into this agreement has allowed additional Recapture Energy exports to external markets helping to ensure maximum value from the organization's hydrological resources.

energy is not planned to be used to serve Labrador customers in the future; however, due to the LIL-Maritime Link relationship, there is the potential for trapped energy (i.e., energy that cannot be delivered to the Island) in Labrador. It also suggests there is a risk of increased requirement for banking of Muskrat Falls energy at Churchill Falls,[81] or an increase in the risk of spill at Muskrat Falls if exports over the Maritime Link are limited or Island load is low. This potential for trapped energy is not considered firm energy for use in the Labrador Interconnected System in this analysis. Hydro will continue to evaluate the opportunity to optimize energy stored on the Labrador Interconnected System, including short-term energy sales, where appropriate.[82]

Treating the Labrador Interconnected System as a separate region from a firm energy perspective will help to ensure reliability in Labrador. This remains true should significant industrial load growth occur. The full results of the Labrador Interconnected System firm energy analysis can be found in the 2024 Expansions Plans.[83]

5.4 Expansion Model Methodology

Once the Planning Reserve Margin is developed and the firm energy analysis has been completed, both are used as inputs into the Expansion Model which is developed using PLEXOS. For the purposes of the Expansion Model, the three Island Interconnected System forecasts were applied as well as the Reference Case load forecast for the Labrador Interconnected System, creating three discrete load forecast scenarios that were used for the resource adequacy analysis.

Many of the assumptions used as inputs to the Reliability Model are also used for the Expansion Model. The following sections detail the methodology and assumptions used to develop the Expansion Model where they differ from the Reliability Model only.

[81] Both Churchill Falls and Muskrat Falls are located on the Churchill River and share water resources to generate electricity. To optimize the usage of stored water resources on the Churchill River system, energy can be stored or "banked" for future usage to efficiently manage water resources.
[82] In 2023, Hydro-Québec expressed interest in purchasing energy banked on the Churchill River system, providing Hydro an opportunity to benefit from shared storage on behalf of customers. Hydro has agreed to sell 1.7 TWh of energy banked in the Churchill River Reservoir on behalf of Muskrat Falls.
[83] Please refer to Section 3.2 of Appendix C.

5.4.1 Transmission

5.4.1.1 On-Avalon Transmission Constraint

Hydro engaged TransGrid to complete a study[84,85] to determine the Bay d'Espoir to Soldiers Pond transmission constraints for contingency scenarios during a LIL bipole outage.[86] The TransGrid Study also presented a series of potential capital transmission upgrade options that could alleviate these constraints to facilitate more new off-Avalon generation. A simplified diagram of the Bay d'Espoir to Soldiers Pond 230 kV transmission system is provided in Figure 7, which includes reference to the Sunnyside, Come by Chance, Western Avalon, and Long Harbour Terminal Stations.

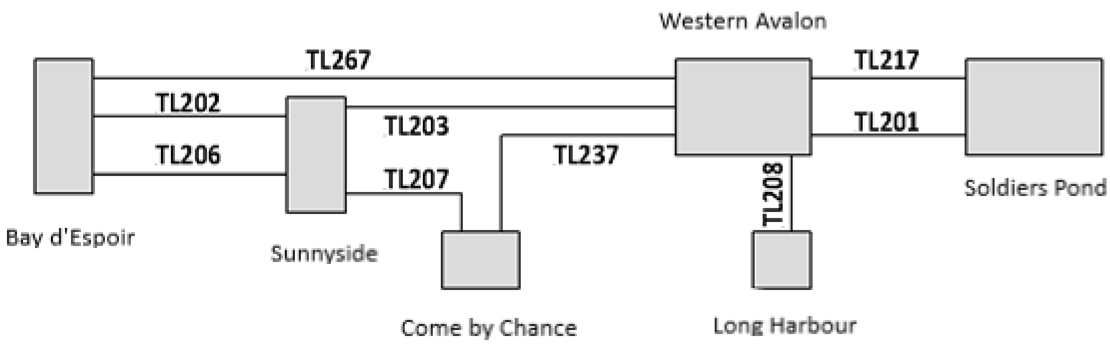


Figure 7: Bay d'Espoir to Soldiers Pond 230 kV Transmission System

Following the transition from generation to SC operations at the Holyrood TGS and the Hardwoods GT, the Bay d'Espoir to Soldiers Pond transmission system must supply the majority of the Avalon's demand during a LIL bipole outage, assuming no new generation sources are constructed on the Avalon. The existing Bay d'Espoir to Soldiers Pond transmission constraints are defined based on 230 kV line contingencies that cause thermal overloads on lines remaining in service and/or low voltage conditions that must be avoided to ensure reliable and safe operation.[87]

[84] "Avalon Supply (Transmission) Study – Overview," Newfoundland and Labrador Hydro, October 31, 2023.
[85] The TransGrid Study serves as a refresh to the "Avalon Capacity Study – Solutions to Serve Island Demand during a LIL Bipole Outage" completed in May 2019. Since the completion of the original study, the Transmission Planning Criteria has been further defined as it relates to a LIL bipole outage. The study is available on the Board website. http://www.pub.nf.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%20Avalon%20Supply%20%20(Transmission)%20Study%20-%20REDACTED%20-%202023-10-31.PDF
[86] The transmission transfer capability west of Bay d'Espoir is less of a factor for the *RRA Study Review*, given the majority of the Island load is east of Bay d'Espoir and the long-term plan is to remove large generation sources on the Avalon.
[87] For example, the sudden loss of TL217 during a LIL bipole outage when Avalon gross load exceeds 664 MW, which corresponds to Island demand of 1,285 MW will result in a thermal overload of TL201.

Understanding the limitations of the Bay d'Espoir to Soldiers Pond transmission system is an important component of the analysis required in support of a Generation Expansion Plan. The addition of new generation sources will impact the flow of electricity in the transmission network. For example, more generation on the Avalon would reduce power flow on the Bay d'Espoir to Soldiers Pond transmission system. This is of particular importance in the event of a LIL bipole outage.

The TransGrid Study had two main objectives that were divided into two phases:[88]

- **Phase 1**: Determine all the existing 230 kV transmission constraints between Bay d'Espoir and Soldiers Pond with current Avalon thermal generation sources unavailable.[89] The analysis involved assessing various 230 kV line contingencies between Bay d'Espoir and Soldiers Pond to determine transfer limits with and without the LIL online.
- **Phase 2**: Determine the increased transfer capacity to the Avalon for various transmission reinforcement options provided by Hydro. This analysis involved assessing various 230 kV line contingencies between Bay d'Espoir and Soldiers Pond for each option.

The primary objective of Phase 1 of the TransGrid Study was to determine all the 230 kV transmission "bottlenecks" between Bay d'Espoir and Soldiers Pond during a LIL bipole outage. The most limiting (N-1) contingency was determined to be the loss of TL217, which overloads TL201. An outage to TL217 during a LIL bipole outage would result in a customer impact when Avalon gross load exceeds 664 MW, which corresponds to Island demand of 1,285 MW.

The following are additional findings from Phase 1 of TransGrid's Study:

- The power flow eastward out of Bay d'Espoir must be limited to 680 MW when the LIL is online in bipole to meet transient under-voltage criteria[90] if there is a three-phase fault near the Western Avalon TS on TL267.[91]

[88] A future third phase will eventually be performed to evaluate the feasibility of a RAS to potentially reduce the scope of capital upgrades evaluated as part of Phase 2.
[89] Unit 3 at the Holyrood TGS and the Hardwoods GT will continue to operate solely as SCs.
[90] Post-fault recovery voltages on the alternating current system shall be as follows:

- Transient under voltages following fault clearing should not drop below 70%; and
- The duration of the voltage below 80% following fault clearing should not exceed 20 cycles.

[91] For this limitation to have an impact and necessitate dispatch of the Holyrood CT, the LIL bipole would have to be derated to approximately 300 MW during peak conditions.

- Avalon generation is required to be in service during peak conditions when the LIL is online in bipole to prevent system instability from occurring should the LIL bipole trip. The following are potential solutions to reduce or eliminate this requirement:
    - The implementation of an RAS to quickly trip Avalon load when the LIL experiences a bipole trip; and/or
    - Bay d'Espoir to Soldiers Pond transmission corridor upgrades, as evaluated in Phase 2.

The primary objective of Phase 2 of the TransGrid Study was to perform a technical evaluation of various options for Bay d'Espoir to Soldiers Pond transmission upgrades to determine the incremental increase in power transfer capacity to the Avalon during a LIL bipole outage following the conversation of the Holyrood TGS and the Hardwoods GT to SC operation. This would have the potential benefit of minimizing customer impact in such a scenario. Once the incremental transfer capacity increase was determined for each trasnsmission upgrade option and a high level cost was assigned to it, each Expansion Plan was paired with the most viable transmission solution to achieve the desired level of reliability. Phase 1, Phase 2, and subsequent steps are discussed in further detail in the 2024 Expansion Plans.[92]

These constraints were incorporated into the resource adequacy study methodology through Transmission Planning's PSSE model, rather than PLEXOS as outlined in Section 4.0.

6.0 Conclusion

As the migration of assumed LIL reliability and operability has evolved since the 2018 Filing, and the subsequent impacts on the Island Interconnected System reliability have been further studied, Hydro is recommending the following:

- The planning of the Island and the Labrador Interconnected Systems on a regional basis;
- Extending pre-existing Island Interconnected System firm energy criteria to the Labrador Interconnected System as a separate region;
- Continuing the evaluation of supply adequacy against the two historical criteria (Probabilistic Capacity and Energy) and the proposed criteria (LIL Shortfall Assessment);

[92] Please refer to Section 7.3 of Appendix C.

- Continuing the evaluation of operational capacity requirements;
- No longer pursuing the adoption of a system reserve margin that satisfies LOLE ≤ 0.1 for the Island Interconnected System at this time; rather, planning to the existing planning criteria of 2.8 LOLH;[93] and
- No longer pursuing the adoption of a system reserve margin that satisfies LOLE ≤ 0.1 for the Newfoundland and Labrador Interconnected System

[93] This does not preclude the potential for adopting a more stringent planning criteria in the future. Hydro will continue to assess this potential of adopting 0.1 LOLE in consideration of the balance between cost and reliability as aging thermal assets are retired and new assets are integrated into the Island Interconnected System.

Appendix B, Attachment 1

Forced Outage Rate Methodology

Forced Outage Rate Methodology

newfoundland labrador hydro

Contents

1.0 Introduction 1
2.0 Hydroelectric Units 3
3.0 Labrador-Island Link 4
3.1 Equivalent Forced Outage Rate 4
4.0 Holyrood Thermal Generating Station 5
5.0 Combustion Turbines 6
6.0 Other 6
6.1 CBPP Co-Gen 6
6.2 St. Lawrence and Fermeuse Wind Farms 7
6.3 Diesels 7
6.4 Newfoundland Power Standby Generation 7

1.0 Introduction

Hydro's asset reliability is a critical component in determining its ability to meet planning criteria for the Newfoundland and Labrador Interconnected System. As an input to the assessment of resource adequacy, unit FORs provide a measure of the expected level of availability in light of unforeseen circumstances.

The FORs used in Hydro's reliability analysis vary by asset class, ownership, and condition.[1] Appropriate FORs are determined in consideration of:

- Historical data, where available;
- Known unresolved issues;
- Industry data; and
- Scenario-based approaches.

The FORs[2] are calculated using different metrics depending on the primary operating mode of the units. For units that primarily operate on a continuous basis, specifically hydroelectric units, the FOR is based on historical DAFOR. For units that primarily operate as peaking/emergency units, specifically CT units, the FOR is based on historical DAUFOP. For the LIL, a bipole EqFOR was calculated and for diesel units, an $EFOR_d$ was used.[3]

For units not owned by Hydro, EC's G-ERIS and NERC's GADS were used to determine the unit's DAFOR or DAUFOP, depending on the unit's generating characteristics. FOR assumptions are evaluated on an annual basis to incorporate the most recent data available.

Table 1 provides a summary of values and measures used for existing generating assets.

---

[1] Hydro files a quarterly assessment on historical FOR and assumptions Hydro uses in its assessments of resource adequacy. For further information, please refer to Hydro's Rolling 12 reports. http://pub.nl.ca/indexreportspages/12MonthRollingAverage.php
[2] FORs include outages that remove a unit from service completely as well as instances when units are derated. If a unit's output is reduced by more than 2%, the unit is considered derated under EC guidelines. These guidelines require that the derated levels of a generating unit be calculated by converting the operating time at the derated level into an equivalent outage time.
[3] EC does not report outage data for diesel units. The closest available industry standard for diesel FORs is the NERC-GADS Report, which uses $EFOR_d$, a similar measure to the DAUFOP.

Table 1: FORs for Existing Generating Assets

Unit Type	Measure	Near-Term Analysis Value (%)[4]	Resource Planning Analysis Value (%)[5]
Hydro-Owned			
Hydraulic[6]	DAFOR	3.90	3.03
Muskrat Falls	DAFOR	3.88	3.03
Thermal	DAUFOP	20	20
GT			
Happy Valley	DAUFOP	4.65	4.65
Hardwoods and Stephenville	DAUFOP	30	30
Holyrood	DAUFOP	4.90	4.90
Diesel	$EFOR_d$	6.58	6.58
LIL[7,8]	EqFOR	1–10	1–10
Power Purchases			
CBPP Co-Gen	DAFOR	19.16	19.16
Rattle Brook	DAFOR	5.82	5.82
Wind	N/A	N/A	N/A
Newfoundland Power Generation			
Hydraulic	DAFOR	5.82	5.82
Standby	DAUFOP	6.19	6.19
Deer Lake Power			
Capacity Assistance	N/A	N/A	N/A
Hydraulic	DAFOR	5.82	5.82

Table 2 provides a summary of values and measures used for expansion resource options. The methodology behind the FORs for each asset class used in the 2024 Resource Plan[9] is discussed in detail in Sections 2.0 through 6.0.

[4] These values are used in Hydro's near-term reliability assessments, which focus on system reliability in years 1 through 5.
[5] These values are used in Hydro's reliability and resource adequacy assessments, which focus on system reliability in years beyond year 5.
[6] Includes units at non-regulated Exploits.
[7] The LIL bipole EqFOR for over both the near term and long term is assumed 5% as the base assumption with 1% and 10% as sensitivities.
[8] The LIL bipole EqFOR from April 1, 2023 to June 1, 2024 was 2.34% with a base capacity of 700 MW.
[9] Hydro's 2024 Resource Plan is filed as part of the ongoing *RRA Study Review*. Hydro's filings within the *RRA Study Review* are available on the Board's website.
http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/index.php

Table 2: FORs for Expansion Resource Options

Unit Type	Measure	Resource Planning Analysis Value (%)
Battery[10]	FOR	0.5
Wind	N/A	N/A[11]
Hydroelectric[12]	DAFOR	3.03
CTs[13]	DAUFOP	4.9
Solar[14]	FOR	0.5

2.0 Hydroelectric Units

For Hydro-owned hydroelectric units,[15] a three-year capacity-weighted average DAFOR was applied for the near-term analysis, while a ten-year capacity-weighted average DAFOR was applied for use in the long-term Resource Planning Model.

The rationale behind utilizing a three-year capacity weighted average for the near-term analysis was to capture near-term items of concern. Because the three-year average varies, it is not consistent enough to accurately reflect anticipated future or long-term performance. Therefore, the rationale behind utilizing a ten-year capacity weighted average for the long-term analysis enables Hydro to capture a broader range of asset health over time. As such, the DAFOR value is based on historical data reflective of Hydro's maintenance program over a long-term period. The average determined for Hydro-owned hydroelectric units was also applied to the Exploits units, as it is assumed they will be maintained to the same standards.

In addition, this report contains FORs for the non-regulated Muskrat Falls. The near-term FORs for Muskrat Falls were based on the FORs of the units to date, to reflect the possibility of increased outages early in the lifetime of the plant. In the long term, the Hydro-owned hydroelectric unit FORs were used,

[10] Please refer to "2018 Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 7.
[11] FORs for the wind generation option was inherently included in the probability distribution.
[12] Assumed DAFOR is consistent with Hydro-owned hydroelectric units used in the long term.
[13] The expected FOR of expansion CTs was calculated using the scenario-based approach described in Section 5.0. Please refer to "2020 Generation Equipment Status - Equipment Reliability Information System - Annual Report," EC, Table 6.3.2.
[14] Please refer to "2018 Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, September 6, 2019 (originally filed November 16, 2018), vol. III, att. 6.
[15] Includes Bay d'Espoir, Cat Arm, Hinds Lake, Granite Canal, Upper Salmon, and Paradise River.

as it is assumed that these assets will be maintained to the same standards as the remainder of the hydraulic fleet.

For hydroelectric units not owned by Hydro (Rattle Brook, Newfoundland Power Hydro, and Deer Lake Power) an industry average FOR was used. The EC G-ERIS Report, which collects outage statistics on an average five-year basis from utilities across Canada, was used to determine the DAFOR.[16] The DAFOR was applied across all units in both the near- and long-term modelling and analysis.

3.0 Labrador-Island Link

As noted in Hydro's 2022 Update, the LIL bipole EqFOR is a key driver for system reliability. Based on observed outage rates during the early years of LIL operation and since its commissioning,[17] Hydro recognizes that the previously anticipated LIL bipole EqFOR of 0.0114% is no longer appropriate.[18,19]

Multiple years of operational experience are required to have more confidence in the LIL bipole EqFOR. In the interim, a range of LIL bipole EqFOR will be assumed with upper and lower limits as additional scenarios in the analysis, including a scenario treating the LIL as an "Energy-Only Line," meaning it is not considered to provide firm capacity, as well as a highly reliable LIL, with an EqFOR of 1%. As LIL performance statistics become available in the coming years, the LIL bipole EqFOR range may be narrowed in future filings. For this analysis, the base-case assumption is that the LIL is available up to a capacity of 700 MW with an assigned 5% LIL bipole EqFOR. Since commissioning, LIL performance has been calculated using a LIL bipole EqFOR, which is discussed further in Section 3.1.

3.1 Equivalent Forced Outage Rate

As the LIL is not a generating unit, conventional FORs used for generating assets do not apply to this asset. Hydro has determined an appropriate metric to be an EqFOR to measure the performance of this asset as it relates to the supply of energy to the Island. The LIL bipole EqFOR measures the percentage of time that the LIL bipole is unable to deliver its Maximum Continuous Rating[20] to the Island due to bipole

[16] "2021 Generation Equipment Status - Equipment Reliability Information System - Annual Report," Electricity Canada, Table 6.1.2.
[17] The LIL was commissioned on April 14, 2023.
[18] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. I, sec. 4.2.1.
[19] The monopole EqFOR is not a significant driver for LIL reliability when assuming a bipole capacity of 700 MW, given the ability for each pole to be loaded to 1.5 times its rated capacity on a continuous basis (675 MW).
[20] Since commissioning, the LIL Maximum Continuous Rating remains at 700 MW.

forced outages, bipole derates, derates due to unplanned monopole outages, or derates due to overlapping monopole outages (effectively creating a bipole outage). The effects of bipole derates and unplanned monopole outages are converted to equivalent bipole outage time to calculate LIL bipole EqFOR. The LIL bipole EqFOR is calculated on a base LIL capacity of 700 MW at present. On the base LIL capacity of 700 MW, the LIL bipole EqFOR was calculated to be approximately 2.34%.[21] On a base capacity of 900 MW, the LIL bipole EqFOR was calculated to be approximately 3.56% during the same period. Following the completion of the 900 MW test and subsequent release for service, all calculations will be adjusted to reflect the change in the maximum continuous rating. However, to date, the calculated LIL bipole EqFOR is well within the assumed long-term range of 1% to 10%.

4.0 Holyrood Thermal Generating Station

The Holyrood TGS has been historically operated as a base-load generation facility with all three units generating during the winter operating season. In addition to operating as a generator, Unit 3 also operates as an SC during the summer months and shoulder periods.[22,23] In the 2022 Update, the reliability of the Holyrood TGS was assessed in the context of its ability to bring units online quickly as well as its ability to operate reliably and at sufficient capacity when called upon.[24] Historically, FORs for the three units at the Holyrood TGS have been reported using the DAFOR metric predominately used for units that operate in a continuous (base-load) capacity.

As presented in the 2022 Update, there are reliability concerns associated with the operation of the units at the Holyrood TGS in a standby capacity. When considering standby or peaking operations of units at the Holyrood TGS, DAFOR is no longer the most appropriate measure of FOR; rather, DAUFOP is a more appropriate measure, given the frequency of deratings historically experienced by these units.[25] Analyses performed for a range of Holyrood TGS DAUFOP assumptions indicate the sensitivity of supply adequacy to changes in Holyrood TGS availability. Therefore, when considering future operations of the Holyrood TGS as a backup generating facility, it was recommended to use an assigned DAUFOP value of

[21] Calculated for the period April 1, 2023 to June 1, 2024.
[22] Converting Unit 3 to SC capability provides reactive power support to the Island Interconnected System and helps regulate system voltage on the Avalon Peninsula.
[23] Unit 3 requires 96 hours to convert from SC mode to generate mode.
[24] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, sec. 5.3.1.
[25] The full analysis can be found in "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, att. 4.

20%.[26] In the 2024 Resource Plan, the appropriate DAUFOP for long-term reliability planning remains 20%. For near-term planning, an assigned DAUFOP of 20% is included with a sensitivity of 34%.[27]

Hydro will continue to analyze the operational data to ensure that FOR assumptions for the Holyrood TGS are appropriate.

5.0 Combustion Turbines

As the CTs (also referred to as GTs) in the existing fleet vary in age and condition, each was considered on an individual basis. For the Happy Valley GT, a three-year capacity-weighted average was applied to the unit for the near-term analysis while a ten-year capacity-weighted average was applied for use in the Resource Planning Model. The DAUFOP values were based on historical data to reflect the unit's past performance. For the Holyrood CT, the DAUFOP was calculated based on a scenario approach rather than historical data due to the unit's minimal historic operating time and resultant small data set. For the Hardwoods and Stephenville GTs, a fixed DAUFOP consistent with values considered in Hydro's previous near-term reliability report was used for the near-term and long-term analyses.[28] The assigned 30% DAUFOP formed the basis for all analyses of the Hardwoods and Stephenville GTs and is based on historical performance in consideration of the age of the assets.[29]

6.0 Other

6.1 CBPP Co-Gen

An industry average FOR is applied to both near- and long-term modelling and analysis. This value is based on the most recent EC G-ERIS Report and the five-year average DAFOR for thermal-biomass units.[30,31]

[26] For details on this recommendation please refer to "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, att. 4.
[27] Reflects actual performance during winter 2021–2022.
[28] "2023 Near-Term Reliability Report – November Report," Newfoundland and Labrador Hydro, November 15, 2023.
[29] "Near-Term Generation Adequacy Report," Newfoundland and Labrador Hydro, November 15, 2017.
[30] "2021 Generation Equipment Status - Equipment Reliability Information System - Annual Report," Electricity Canada, Table 6.2.18.
[31] EC provides values on an average five-year basis.

6.2 St. Lawrence and Fermeuse Wind Farms

Hydro models wind generation stochastically using probability distribution functions developed for summer and winter generation at the Fermeuse and St. Lawrence Wind Projects. The FOR is inherently included in the probability distribution for both near- and long-term modelling and analysis.

6.3 Diesels

The $EFOR_d$ from the most recent NERC-GADS Report is applied to all diesel units for the near- and long-term modelling and analysis.[32,33] The $EFOR_d$ is a measure used by NERC which is comparable to DAUFOP.[34]

6.4 Newfoundland Power Standby Generation

A five-year average DAUFOP obtained from the most recent EC G-ERIS Report for CT units is applied for all CT units in both near- and long-term modelling and analysis.[35,36] In addition, Hydro has assigned a DAUFOP of 30% to Newfoundland Power's Greenhill and Wesleyville GTs, as they are nearing the end of their service lives, which is in line with what is used for Hydro-owned CTs nearing end-of-life (e.g., both the Stephenville and Hardwoods GTs) to ensure Hydro is not over-relying on these units. Should Newfoundland Power's plans for these units change, Hydro will update the model accordingly.

[32] "Generating Unit Statistical Brochure 4 2017- 2021 - All Units Reporting," North American Electric Reliability Corporation, August 1, 2021.
https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx
[33] As EC does not track diesel FORs, the NERC-GADS Report was used.
[34] The Institute of Electrical and Electronics Engineers (2007). 762-2006, *Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity*.
[35] "2021 Generation Equipment Status - Equipment Reliability Information System - Annual Report," Electricity Canada, Table 6.3.2.
[36] EC provides values on an average five-year basis.

Appendix B, Attachment 2

Energy Analysis Memo

Daymark Energy Advisors

May 9, 2024

DAYMARK®
ENERGY ADVISORS

MEMORANDUM

TO: Samantha Tobin, Newfoundland and Labrador Hydro

FROM: Phil DiDomenico, Daymark Energy Advisors

DATE: May 9, 2024

SUBJECT: Energy Analysis Memo

BACKGROUND

As part of the 2024 Reliability & Resource Adequacy preparation and filing, Daymark was asked to review Hydro's Firm Energy Analysis for the Island Interconnected System. The analysis is part of Hydro's resource planning process. Performed before the system expansion model is run, the results feed into determining overall system requirements to be optimized against. Hydro has historically and continues to perform Firm Energy Analysis outside of its primary system expansion modeling tool (PLEXOS); however, the results of the analysis are integrated into the expansion planning process as inputs to the PLEXOS model. Overall the approach may benefit from closer coordination with the PLEXOS model, or integration to the PLEXOS model either wholistically or as a set of stand-alone studies. Studying a system's energy adequacy is an industry-standard planning process, especially for systems with a significant portion of hydroelectric resources and those with hydrocarbon import constraints, such as Hydro's. In Daymark's review, Hydro's Firm Energy Analysis is technically sound. We recommend that Hydro begin co-optimizing firm energy and capacity requirements using the PLEXOS expansion modelling tool in future filings.

ENERGY PLANNING IN THE UTILITY INDUSTRY

In several parts of North America, balancing areas' planning revolves around the planning reserve margin, calculated as the difference between Deliverable or Prospective Resources and Net Internal Demand, divided by Net Internal Demand.[1] For systems that are not energy-limited, ensuring a reserve margin that allows operators to deal with unforeseen increases in demand and unexpected generator outages may be sufficient for planning to meet loss-of-load targets. However, systems that are energy-limited may need to complement reserve margin analyses with deterministic and/or probabilistic analyses of energy requirements during the planning horizon.

[1] https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx

Several factors are increasing the importance of energy analysis across the industry. Electrification of both heating and transportation are expected to increase the energy burden placed on systems in addition to the peak load conditions they present. Another dynamic which is increasingly being reviewed in industry is winter energy adequacy. Planning entities are reviewing whether their systems will have the fuel on hand to deal with prolonged and widespread cold events, especially as electric heating burden increases. The transition of capacity to energy-limited resources such as batteries and the rest of fleets to an increasing portion of variable renewable resources also necessitates proper consideration of energy implications within resource adequacy. Systems which feature hydroelectric facilities, such as Hydro's, have historically reviewed their firm energy capabilities against their planning criteria. Hydro has performed this analysis as part of past Resource Adequacy reviews, although Daymark understands that energy constraints have not been binding in recent resource expansion plans.

Accordingly, Daymark finds Hydro's consideration of the energy analysis appropriate given the nature of its system and industry factors.

HYDRO'S ANALYSIS

The Firm Energy Analysis which Daymark reviewed is an external, spreadsheet-based model. The external analysis differs from the PLEXOS-based planning with regards to some of the inputs. The external analysis is a deterministic and conservative consideration of future system conditions, however this is vitally important for determining that there are sufficient firm energy resources available to meet system load, even under adverse conditions. Due to the nature of expansion planning simulation, the granularity of a single step of the problem is large, however due to some of the simplifying assumptions made for the spreadsheet based tool, it is able to evaluate energy requirements on a much more granular basis than a typical expansion planning model would use. This additional granularity brings benefits ensuring that for edge, or worse case, conditions there are adequate energy resources available on the system. As we will discuss further below, this is a useful planning tool, provided it is applied appropriately.

The Firm Energy Analysis compares the energy generating capability of the existing fleet under a set of assumptions against the expected load for each year of the 2024-2034 planning horizon. For each year, the analysis outputs the energy surplus or deficit. The analysis contains several scenarios. The scenarios look at three values of the Island load forecast: Reference, Slow Decarbonization, and Accelerated Decarbonization.

Key assumptions regarding the firm energy capability of the system are as follows:

(1) Output from Hydro-owned reflects energy from worst-case historical drought sequence for the "Firm Gen" scenario.

(2) Newfoundland Power-owned and Star Lake and Exploits hydraulic generation reflect low hydrology compared to average hydrology based on historical data.

(3) Holyrood's output reflects its retirement as a generation facility in Spring 2030 (Units 1 and 2 retired and Unit 3 permanently converted to synchronous condenser mode).

(4) Energy contributions from combustion turbines and diesel units are not considered for either Hydro-owned or Newfoundland Power-owned resources.

(5) Energy contributions from imports over the Maritime Link are not considered.

(6) Delivery of the Nova Scotia Block contractual commitment is considered.

(7) Energy delivery from Labrador to Newfoundland is constrained by LIL transmission operations dependencies, which are dependent on on-Island load, and energy exports over the Maritime Link.

In all scenarios, energy shortfalls are present beginning in 2030, following the retirement of the Holyrood Thermal Generating Station, and continue to increase to the end of the forecast horizon.

Overall, Daymark considers Hydro's approach of comparing yearly generation to yearly load within the Firm Energy Analysis technically sound. Daymark stresses the importance of being aware of the various input assumptions of the Firm Energy Analysis — specifically, the use of worst-case historical drought conditions, inability to use combustion turbines or diesel units and the inability to import energy across the Maritime Link transmission line — when interpreting the results.

CONCLUSIONS AND RECOMMENDATIONS

The Firm Energy Analysis which Hydro performed in association with the 2024 Reliability and Resource Adequacy filing is technically sound and comports with industry-standard planning practices.

Daymark notes that the Firm Energy Analysis is not co-optimized with the capacity expansion modelling (PLEXOS) but rather feeds into the capacity expansion modelling as a series of inputs. Daymark understands that the PLEXOS-based planning activities led to insufficient energy resources to meet Hydro's energy planning criteria. Hydro thus used the results of the Firm Energy Analysis to determine a profile of wind generation additions to fix in the model, around which the optimal capacity expansion plan was developed. Daymark supports this approach; however, recommends adapting the PLEXOS model to be able to co-optimize energy and capacity resources to meet both planning criteria.

The Firm Energy Analysis is a deterministic, annualized assessment of the system's energy adequacy. The analysis will not identify, for example, winter energy sufficiency taking into account individual hydraulic units' operating parameters and fuel import constraints. Hydro's PLEXOS-based planning framework, however, is better equipped to examine the system's ability to probabilistically meet energy needs in such scenarios and Hydro is using this tool to analyze winter energy adequacy, specifically during a potential extended outage of the Labrador Island Link.

Because of the usage of the Firm Energy Analysis is acting as a verification of resource sufficiency and the increasingly nuanced and situational nature of energy shortfall events, Daymark recommends bringing the Firm Energy Analysis into greater alignment with the overall resource planning process using Hydro's PLEXOS model.

Appendix C

Appendix C

2024 Expansion Plans

Development and Process Recommendation

2024 Expansion Plans

Development Process and Recommendation

Contents

1.0 Introduction 1
2.0 Capacity Requirements 7
2.1 Island Interconnected System 7
2.2 Labrador Interconnected System 10
3.0 Firm Energy Requirements 12
3.1 Island Interconnected System 12
3.2 Labrador Interconnected System 17
4.0 Expansion Resource Options Under Consideration 18
4.1 ECDM 22
4.1.1 Electrification Programming 22
4.1.2 Future ECDM Programming 24
4.2 Capacity Assistance 25
4.3 Hydroelectric Generation 25
4.3.1 Bay d'Espoir Unit 8 26
4.3.2 Cat Arm Unit 3 27
4.3.3 Island Pond Development 27
4.3.4 Round Pond Development 28
4.3.5 Portland Creek Development 28
4.3.6 Exploits River Development 29
4.3.7 Incremental Capacity/Efficiency Potential 30
4.3.7.1 Bay d'Espoir Unit 7 Uprate Study 30
4.4 CT Generation 31
4.4.1 Fuel Market Study 32
4.4.2 Supply Options in the Short-Term 33
4.4.2.1 Combustion Turbines 33
4.4.2.1.1 Fuel Type 33
4.4.2.1.2 Synchronous Condensing 34
4.4.2.1.3 Balance of Plant Equipment 35
4.4.2.1.4 Shipment, Storage, and Preservation 35
4.4.2.2 Transformers 35

4.4.2.3 Costs and Schedule 35
4.4.2.4 Potential Cost and Emissions Reduction 36
4.5 Wind Generation 38
4.6 Battery Storage Technology 39
4.6.1 Short-Duration Battery Storage Technology 39
4.6.2 Long-Duration Battery Storage Technology 40
4.7 Solar 41
4.8 Market Purchases 41
4.9 Pumped Storage 42
4.10 Renewal of Existing PPAs 44
5.0 Resource Options Not Under Consideration 44
5.1 CCCTs 44
5.2 Modular Nuclear 45
6.0 Expansion Plan Development Process 45
6.1 Development of Expansion Plan Scenarios 46
6.2 Development of Expansion Plan Sensitivities 48
6.2.1 Scenario 1: Reference Case 49
6.2.1.1 Resource Requirements 50
6.2.1.1.1 Scenario 1: Unrestricted 51
6.2.1.1.2 Scenario 1A: Fixed Wind Profile 52
6.2.1.1.3 Scenario 1AB40: Fixed Wind Profile and Battery ELCC of 40% 53
6.2.1.1.4 Scenario 1AB80: Fixed Wind Profile and Battery ELCC of 80% 54
6.2.1.1.5 Shortfall Analysis Scenario: Batteries vs CT 55
6.2.1.1.6 Scenario 1AC: Fixed Wind Profile and No Fuel Burn-Off 57
6.2.1.1.7 Scenario 1AD: Fixed Wind Profile and Hydro Capital Costs + 50% 58
6.2.1.1.8 Scenario 1AE: Fixed Wind Profile and No Batteries 59
6.2.1.1.9 Scenario 1AEC: Fixed Wind Profile, No Batteries, and No Fuel Burn-Off 60
6.2.1.1.10 Scenario 1AEF: Fixed Wind Profile, No Batteries, and Limit CT 60
6.2.1.1.11 Scenario 1AEG: Fixed Wind Profile, no Batteries, and Increase Fuel Costs 61
6.2.1.1.12 Scenario 1AEH: Fixed Wind Profile, no Batteries, and Increase CT Capital Costs 62
6.2.1.1.13 Scenario 1AEI: Fixed Wind Profile, No Batteries, and Include NP CT Additions 63

6.2.1.2 NPV Comparison 64
6.2.1.3 Annual Emissions Comparison 65
6.2.1.4 Summary of Scenario 1 (Reference Case) Expansion Plans 66
6.2.2 Scenario 4: Minimum Investment Required 68
6.2.2.1 Resource Requirements 69
6.2.2.1.1 Scenario 4: Unrestricted 69
6.2.2.1.2 Scenario 4A: Fixed Wind Profile 70
6.2.2.1.3 Scenario 4AB40: Fixed Wind Profile and Battery ELCC of 40% 71
6.2.2.1.4 Scenario 4AB80: Fixed Wind Profile and Battery ELCC of 80% 72
6.2.2.1.5 Scenario 4AC: Fixed Wind Profile and No Fuel Burn-Off 73
6.2.2.1.6 Scenario 4AD: Fixed Wind Profile and Hydro Capital Costs + 50% 73
6.2.2.1.7 Scenario 4AE: Fixed Wind Profile and no Batteries 74
6.2.2.1.8 Scenario 4AEC: Fixed Wind Profile, No Batteries, and No Fuel Burn-Off 75
6.2.2.1.9 Scenario 4AEF: Fixed Wind Profile, No Batteries, and Limit CTs 76
6.2.2.1.10 Scenario 4AEG: Fixed Wind Profile, No Batteries, and Increase Fuel Costs 76
6.2.2.1.11 Scenario 4AEH: Fixed Wind Profile, No Batteries, and Increase CT Capital Costs 77
6.2.2.1.12 Scenario 4AEI: Fixed Wind Profile, No Batteries, and Include NP CT Additions 78
6.2.2.2 NPV Comparison 79
6.2.2.3 Annual Emissions Comparison 80
6.2.2.4 Summary of Scenario 4 (Minimum Investment Required) Expansion Plans 81
6.2.3 Discussion: Sensitivities Key Learnings 82
6.2.3.1 Energy Requirements 82
6.2.3.2 Capacity Requirements 82
6.3 Expansion Plan Results for all Scenarios 84
6.3.1 Resource Requirements 84
6.3.1.1 Scenario 2AEF: Accelerated Decarbonization, LIL Bipole EqFOR 5% 84
6.3.1.2 Scenario 3AEF: Slow Decarbonization, 5% LIL Bipole EqFOR 85
6.3.1.3 Scenario 5AEF: Accelerated Decarbonization, 10% LIL Bipole EqFOR 86
6.3.1.4 Scenario 6AEF: Accelerated Decarbonization, 1% LIL Bipole EqFOR 87
6.3.1.5 Scenario 7AEF: Slow Decarbonization, 5% LIL Bipole EqFOR, 0.1 LOLE 88
6.3.1.6 Scenario 8EF: Reference Case, LIL Energy-Only 89

6.3.2 Net Present Value Comparison ... 89
6.3.3 Emission Comparison ... 91
6.3.4 Summary of Expansion Plans ... 92
6.3.5 Discussion: Expansion Plan Scenarios ... 94
6.3.5.1 Energy Requirements ... 94
6.3.5.2 Capacity Requirements ... 94
6.3.5.2.1 Resource Options ... 95
6.3.5.2.2 Planning Criteria Comparison ... 95
6.3.5.2.3 Load Forecast Comparison ... 95
6.3.5.2.4 LIL Reliability Comparison ... 95
7.0 Further Testing of the Expansion Plans ... 96
7.1 The Expansion Plan and *CER* ... 97
7.2 The Expansion Plan and the LIL Shortfall Analysis ... 100
7.2.1 Combination 1 ... 102
7.2.2 Combination 2 ... 104
7.2.3 Combination 3 ... 105
7.2.4 Combination 4 ... 107
7.2.5 Impact of Extended LIL Outage on Island Reservoir Storage ... 109
7.3 The Expansion Plan and On-Avalon Transmission Constraints ... 111
7.3.1 Summary of TransGrid Study Results ... 112
7.3.1.1 Phase 1 ... 112
7.3.1.2 Phase 2 ... 113
7.3.2 Expansion Plan Transmission Requirements ... 115
7.3.2.1 No Bay d'Espoir to Soldiers Pond Transmission Upgrades Applied ... 116
7.3.2.1.1 Scenario 1: Reference Case ... 117
7.3.2.1.2 Scenario 4: Minimum Investment Required ... 118
7.3.2.2 Transmission Capacity Increase (Option 4) ... 118
7.3.2.2.1 Scenario 1: Reference Case ... 119
7.3.2.2.2 Scenario 4: Minimum Investment Required ... 120
7.3.2.3 Transmission Capacity Increase (Option 4 or Equivalent + Reactive Power Support) ... 120
7.3.2.3.1 Scenario 1: Reference Case ... 121

7.3.2.3.2 Scenario 4: Minimum Investment Required 121
7.3.3 Recommended Transmission Upgrades 122
7.4 Expansion Plan Iterative Process 124
7.4.1 The Expansion Plan and Rate Impacts 124
7.4.2 The Expansion Plan and Load Forecast Impacts 130
7.4.3 Expansion Plan Iteration 133
7.4.4 Shortfall Analysis on Iterated Expansion Plan 135
8.0 Recommended Expansion Plan 139
8.1 Minimum Investment Required Expansion Plan 140
8.2 Meeting Hydro's Planning Criteria 146
9.0 Action Plan 147
9.1 Action Plan to Meet Energy Requirements 147
9.2 Action Plan to Meet Transmission Requirements 148
9.2.1 On-Avalon Transmission 148
9.2.2 Labrador-Island Link 148
9.3 Action Plan to Meet Capacity Requirements 149
9.3.1 Major Projects: Building Capability and Capacity 150
9.3.2 Major Projects Life Cycle 152
9.3.3 Completion of Front-End Planning 154
10.0 Ongoing Resource Planning Efforts 155
11.0 Conclusion 157

List of Attachments

Attachment 1: "Resource Cost Comparison," Daymark Energy Advisors, April 1, 2024

Attachment 2: "Uprate Report," Hatch Ltd., June 27, 2024

Attachment 3: "Accelerated Holyrood Combustion Turbine Installation Options Study—Final Report," Stantec Consulting Ltd., May 13, 2024

Attachment 4: "Long-Term Fuel Supply Study, Holyrood," Stantec Consulting Ltd., May 6, 2024

Attachment 5: "Impact of Prolonged Loss of LIL on Island Reservoir Levels," Hatch Ltd., July 2, 2024

1.0 Introduction

Hydro's resource planning activities are focused on satisfying loss of load criteria while ensuring sufficient resources to meet operational reserves and sufficient resources to meet energy requirements. Hydro's reliability planning criteria consists of long-standing criteria that have been used to meet system reliability for decades. In addition, more recent planning criteria have been included to reflect the interconnection to the North American Grid via the Maritime Link and the completion of the LIL.

Supply expansion decisions are based on Hydro's previously established[1] resource planning criteria, detailed as follows:

- **Probabilistic Capacity:** The Island Interconnected System should have sufficient generating capacity to satisfy an LOLH expectation target of not more than 2.8 hours per year.[2,3]
- **Energy:** Both the Island and Labrador Interconnected Systems should have sufficient generating capability to supply all its firm energy requirements with firm system capability.

Additional capacity criteria was established by Hydro in the 2018 Filing,[4] detailed as follows:

- **LIL Shortfall Assessment:** The Island Interconnected System should have sufficient generating capacity to limit the loss of load to a manageable level in the case of a LIL shortfall event.[5]

Additionally, Hydro has proposed to adopt the following operational planning criteria, as established in the 2018 Filing:

- **Operational Capacity:** The Newfoundland and Labrador Interconnected System should have sufficient generating capacity to meet its peak load while maintaining sufficient operational reserves.

---

[1] The establishment of the probabilistic capacity criteria occurred in the 1980s and the firm energy criteria in the 1990s.
[2] The previous resource adequacy target of two outage days in ten years, or an LOLE of 0.2, was chosen at the time over the alternative criteria of one day in ten years, or an LOLE of 0.1, to decrease cost of meeting target. A change in software necessitated a benchmarking process to translate the LOLE to LOLH, at which point it was determined that the LOLE of 0.2 could be approximated as an LOLH of 2.8 hours per year.
[3] Further discussion on 0.1 LOLE versus 2.8 LOLH planning criteria can be found in Section 5.1.7 of Appendix B.
[4] Hydro's filings within the *RRA Study Review* are available on the Board's website. http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/index.php
[5] The loss of the LIL bipole is considered a high consequence event impacting the Island Interconnected System. While it does not have specified planning criteria, planning to mitigate the consequences of a prolonged LIL outage is essential and Hydro continues to evaluate reliability implications of an extended LIL outage as part of the resource planning process.

More detail on the Island and Labrador Interconnected Systems' planning criteria can be found in Appendix B. How Hydro is planning to meet these criteria is captured herein.

In the 2018 Filing and 2019 Update, Hydro recommended planning on a regional (Newfoundland and Labrador Interconnected System) and sub-regional (Island Interconnected System) basis. At that time, planning on a Newfoundland and Labrador Interconnected System basis was appropriate given the assumed LIL bipole EqFOR of 0.0114%.[6] This meant that future load growth on either the Labrador or the Island Interconnected System had approximately the same impact on Newfoundland and Labrador Interconnected System reliability. However, given the reliance on the LIL as a source of supply to the Island, it was prudent to incorporate specific consideration of the Island Interconnected System should the LIL not be available. By adopting a separate requirement for the Island Interconnected System, the planning process ensured continued reliability for both the province as a whole and on the Island. In the 2022 Update, Hydro committed to reassessing this approach due to the decrease in expected long-term LIL bipole availability.

From a capacity perspective, as the LIL bipole EqFOR has materially increased from 0.0114% to an assumed range of 1% to 10% and LIL bipole outages become the primary driver of generation shortfall on the Island Interconnected System, there is far less correlation between the Labrador Interconnected System demand and the Newfoundland and Labrador Interconnected System reliability. In Hydro's analysis, Muskrat Falls generation is assumed fully available for the Island Interconnected System. Therefore, during the winter months, the LIL's capacity is maximized via deliveries from Muskrat Falls generation and there is little, if any, ability for additional sources of generation to be brought to the Island. Therefore, an increase in Labrador demand would not impact Island Interconnected System reliability, as the LIL is already maximized by Muskrat Falls generation. Load growth requirements in Labrador would have to be met by new generation sources in Labrador. Subsequently, a theoretical decrease in Labrador demand would not make a significant amount of additional capacity available to the Island Interconnected System, as the LIL is fully utilized in the winter period via deliveries from Muskrat Falls generation. Therefore, given the material increase of the LIL bipole EqFOR assumption, and consideration of the designed capacity of the LIL, it has become necessary to reassess this approach

[6] Hydro previously used "bipole forced outage rate" in reference to the LIL; this was changed in January 2024 to "LIL bipole EqFOR."

in this update and, instead, adopt separate planning criteria for the Island Interconnected System and the Labrador Interconnected System as two separate regions.[7]

From an energy perspective, it is also necessary to decouple the two interconnected systems. Further analysis has been completed to define the operational relationship between LIL flow, Island Interconnected System demand, and Maritime Link flow. Under normal system conditions, the amount of energy that can flow over the LIL to the Island is limited by the interdependencies with the Maritime Link and Island load. This interdependence exists because both HVdc links must work together using Special Protection Schemes that will suddenly reduce their power flows (runbacks) in order to transiently regulate system frequency in the event a contingency occurs on the other HVdc link. This LIL-Maritime Link relationship has less of an impact on the amount of power that can be absorbed on the Island than the amount of UFLS available and that would be triggered following a LIL bipole trip. The amount of available UFLS is directly proportional to the total Island load.[8] As a result, it is now confirmed that there are restrictions on the amount of energy that is able to flow from Muskrat Falls to the Island, resulting in the recommendation to consider the two regions independently when assessing firm energy requirements.[9]

Development in Labrador is important to Hydro and the province; there continues to be merit in planning for the Labrador Interconnected System as a separate region to ensure reliability in Labrador is maintained, which will require the development of Labrador-specific planning criteria in the future. Supply of large new loads in Labrador can involve both transmission and generation supply investments. Hydro meets regularly with various customers to understand and analyze customers' potential needs. Due to the potential cost for customers, this is an iterative feedback process with customers to refine opportunities for the future. Transmission analysis is progressing in accordance with the approved *NAP*,[10] with System Impact Studies underway for proponents who wish to proceed. Opportunities for generation supply are open to both customer self-supply and supply from Hydro; this mix will continue to be considered as customers' needs evolve over the coming years. Additional discussion regarding load growth and planning for the Labrador Interconnected System can be found in Sections 2.2 and 3.2.

---

[7] Additional information can be found in Section 3.1 of Appendix B.
[8] Please refer to Section 3.1 for additional information on this relationship.
[9] Additional information can be found in Section 3.1 of Appendix B.
[10] Newfoundland and Labrador Hydro (2020). *Network Additions Policy – Labrador Interconnected System*. https://nlhydro.com/wp-content/uploads/2021/03/Network-Additions-Policy.pdf

Due to the separation of planning criteria for the Island Interconnected System and the Labrador Interconnected System, Hydro's 2024 Resource Plan focuses on the expansion of the Island Interconnected System only for the study period 2024 through 2034.

Throughout the Island Interconnected System Resource Plan analysis, and in line with Hydro’s mandate, three key considerations were at the forefront of all decision-making, as shown in Figure 1—least cost, reliability, and environment.

Figure 1: Key Considerations of the Resource Plan

With these key considerations in mind, this document outlines the systematic process followed by Hydro to develop the recommended Expansion Plan for the Island Interconnected System that is presented in the 2024 Resource Plan. This document consists of eight main categories, specifically:

1) **Overview of Capacity Requirements (Section 2.0):** The capacity requirements for both the Island and Labrador Interconnected Systems are provided through capacity load resource balance plots for each of the load forecast scenarios developed and in consideration of retiring assets and required Planning Reserve Margins.

2) **Overview of Firm Energy Requirements (Section 3.0):** The firm energy requirements for both the Island and Labrador Interconnected Systems are provided through energy load resource balance plots for each of the load forecast scenarios developed and in consideration of retiring assets.

3) **Overview of the Island Interconnected System Expansion Resource Options (Section 4.0):** All expansion resource options included in the Expansion Model to meet the capacity and energy requirements are discussed in detail, including short-term supply options. Some resource options may not have been included in the 2024 Resource Plan at this time, as their suitability as a resource option is being studied or is planned to be studied in the near future.

4) **Resource Options not Under Consideration (Section 5.0):** This section provides the options and rationale for exclusion from consideration at this time.

5) **Overview of the 2024 Expansion Plan Development Process and Results (Section 6.0):** This section walks through the 8 Expansion Plan scenarios developed to test a wide range of inputs, such as load forecast scenarios, LIL reliability, and planning criteria. Following this, 11 sensitivities were developed to test select Expansion Plan scenarios to determine the drivers for change to the Expansion Plan. Following the outcome of this analysis, select sensitivities were applied to the final Expansion Plan results for all scenarios.

6) **Additional Testing of the 2024 Expansion Plans (Section 7.0):** This section describes the additional analysis conducted for specific Expansion Plans as follows:

   - Compliance with the draft *CER*;[11]
   - The LIL Shortfall Analysis: to determine the level of shortfall that remains should the LIL be offline on an extended bipole outage;
   - On-Avalon Transmission Constraints: to determine the least-cost transmission upgrade required to alleviate trapped Off-Avalon generation during a LIL bipole outage;
   - An Expansion Plan Iterative Process: to determine how the cost of the Expansion Plan could affect rates, in turn affecting the load forecast with potential impacts to the Expansion Plan.

7) **The Recommended 2024 Expansion Plans (Section 8.0):** This section details Hydro's logic in determining the recommended Expansion Plan and the reasoning behind proposing the Minimum Investment Required Expansion Plan at this time.

---

[11] "Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations," Government of Canada, August 19, 2023. https://www.gazette.gc.ca/rp-pr/p1/2023/2023-08-19/html/reg1-eng.html

8) **Hydro's Action Plan and Ongoing Resource Planning Efforts (Sections 9.0 and 10.0):** Finally, these sections detail the action plan to meet firm energy, capacity and transmission requirements during the study period. Also discussed are plans to advance the resource planning process.

Before developing the Island Interconnected System Expansion Plan, Hydro first developed the following major inputs, each of which is discussed in detail in Appendix B.

- A load forecast and scenarios for the Island Interconnected System (Reference Case, Slow Decarbonization, and Accelerated Decarbonization scenarios) and a Reference Case load forecast for the Labrador Interconnected System;[12,13]
- Reliability planning criteria;[14]
- A range of LIL bipole EqFORs; and
- A series of Planning Reserve Margins (developed using the PLEXOS Reliability Model).

All other steps in the 2024 Resource Plan are included herein. At a high level, the 2024 Resource Plan development process is outlined in Figure 2.[15]

[12] For detailed information on the 2023 load forecast and methodology, please refer to "Long-Term Load Forecast Report – 2023," Newfoundland and Labrador Hydro, March 28, 2024.
[13] Hydro also developed Labrador Interconnected System Load Forecast Scenarios for Medium Growth and High Growth that were not used for the Island Interconnected System Expansion Plan analysis.
[14] For detailed information on Hydro's study methodology, planning criteria, assumptions, and Planning Reserve Margin calculations, please refer to Appendix B.
[15] A detailed diagram and explanation of the resource plan process can be found in Section 4.0 of Appendix B.

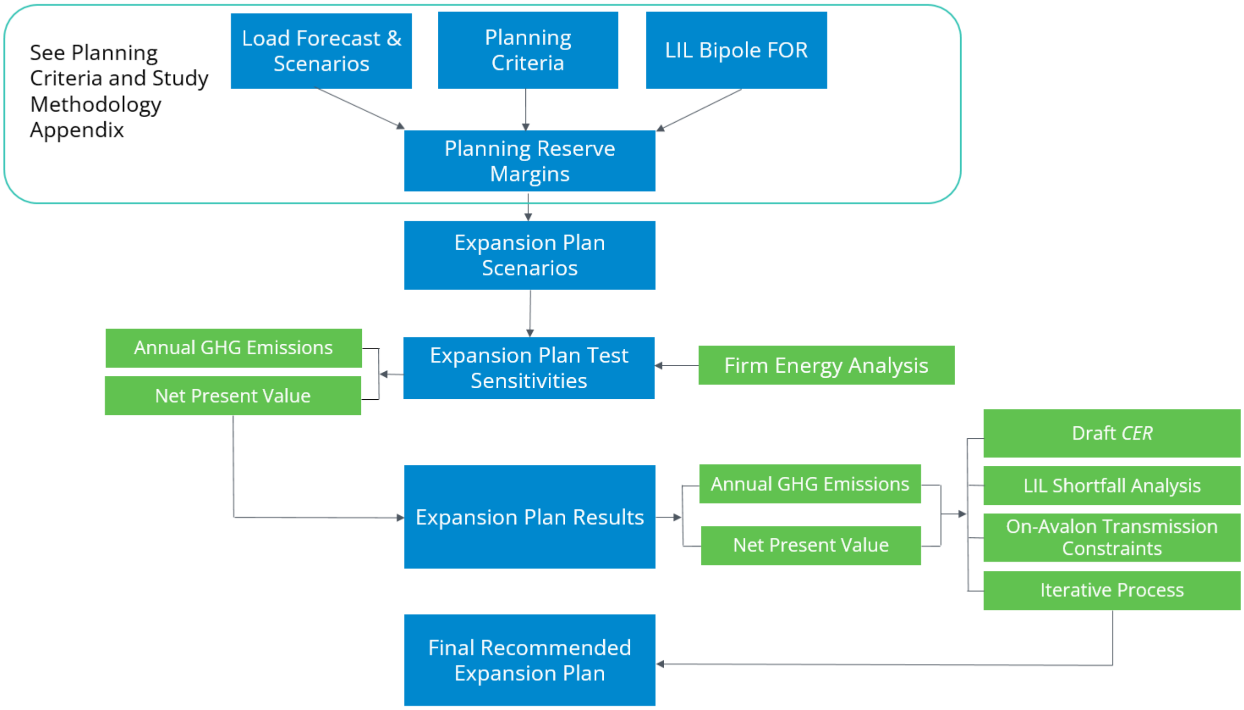


Figure 2: Expansion Plan Development Process

2.0 Capacity Requirements

As per the Reliability Model assumptions and study methodology discussed in detail in Appendix B, Sections 2.1 and 2.2 provide an overview of the capacity requirements for the Island and Labrador Interconnected Systems over the study period.

2.1 Island Interconnected System

The capacity load resource balances for each year in the planning horizon (2024 to 2034), for the three Island Interconnected System load forecast scenarios (Slow Decarbonization, Reference Case, and Accelerated Decarbonization) are provided in Chart 1 to Chart 3. In each chart, resources are identified by stacked columns, load including losses for each load forecast scenario is represented by the dotted line, and load including losses and corresponding Planning Reserve Margin requirement is represented by the dashed line.

The Planning Reserve Margin includes an expected reliability of 5% LIL bipole EqFOR,[16] resulting in a Planning Reserve Margin requirement of approximately 26%. This equates to a reserve requirement of approximately 500 MW (depending on the year and load forecast scenario) to meet a planning criteria of 2.8 LOLH.[17] Consistent amongst all load forecast scenarios (once the Holyrood TGS, Hardwoods GT, and Stephenville GT retire in 2030), the Island Interconnected System will no longer meet its reliability criteria without generation expansion.

The stacked columns are grouped into six main categories, which include the following:

1) **NLH Hydro**: Includes capacity from the following Hydro-owned hydroelectric facilities: Bay d'Espoir, Cat Arm, Granite Canal, Hinds Lake, Paradise River, and Upper Salmon.
2) **Non-NLH**: Includes capacity from Newfoundland Power's thermal and hydro resources, hydroelectric facilities at Deer Lake and Exploits, and other NUGS such as CBPP Co-Gen and the wind farms in St. Lawrence and Fermeuse.
3) **Firm Transmission**: Includes firm capacity from the LIL that is sunk on the Island. The firm contractual commitment to Nova Scotia is not included in this amount, as it is met by Muskrat Falls generation and exported via the Maritime Link.
4) **Capacity Assistance**: Includes contractual arrangements with independent entities (such as CBPP, Newfoundland Power, and Vale) to either increase generation or reduce load.
5) **NLH Standby**: Includes capacity from the following Hydro-owned thermal generating facilities (except the Holyrood TGS, which is shown separately): Hardwoods GT, Stephenville GT, Holyrood CT, and the diesel generating stations in Hawkes Bay, Holyrood, and St. Anthony.
6) **NLH Holyrood**: Includes capacity from the Holyrood TGS, which is assumed retired in 2030.[18]

[16] Since commissioning, LIL performance has been calculated using a LIL bipole EqFOR. The LIL bipole EqFOR measures the percentage of time that the LIL bipole is unable to deliver its Maximum Continuous Rating to the Island due to bipole forced outages, bipole derates, derates due to unplanned monopole outages, or derates due to overlapping monopole outages (effectively creating a bipole outage). Please refer to Section 3.1 of Attachment 1 to Appendix B for additional information on LIL bipole EqFOR.
[17] Please refer to Section 5.1.7 of Appendix B.
[18] As discussed in the Resource Plan Overview, the units at the Holyrood TGS, Hardwoods GT, and Stephenville GT shall remain available through the Bridging Period until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.

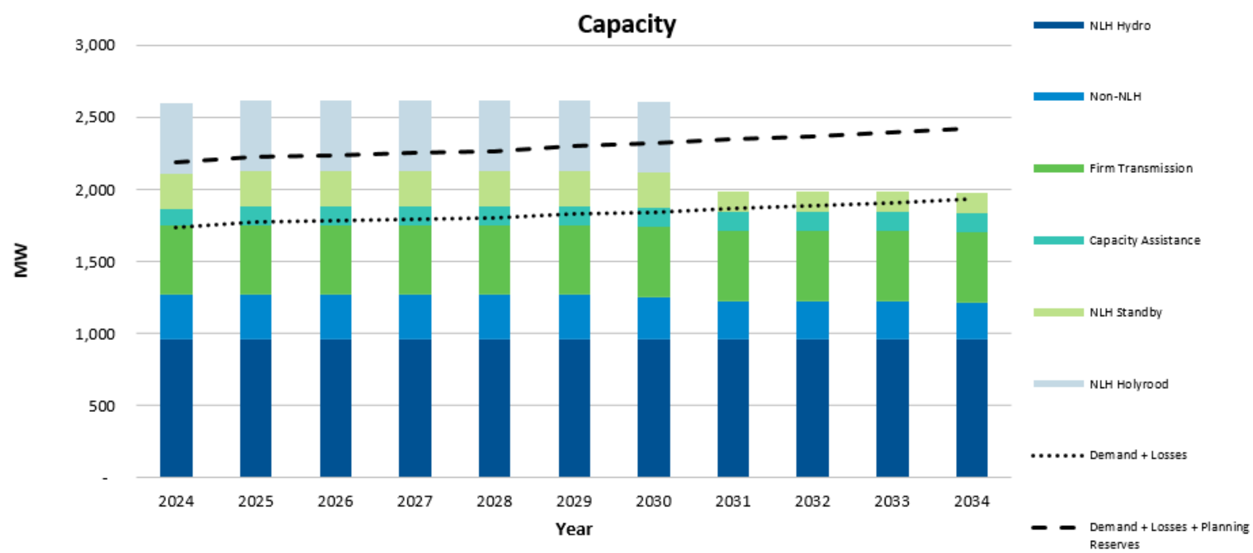


Chart 1: Island Capacity – Slow Decarbonization Load Forecast[19]

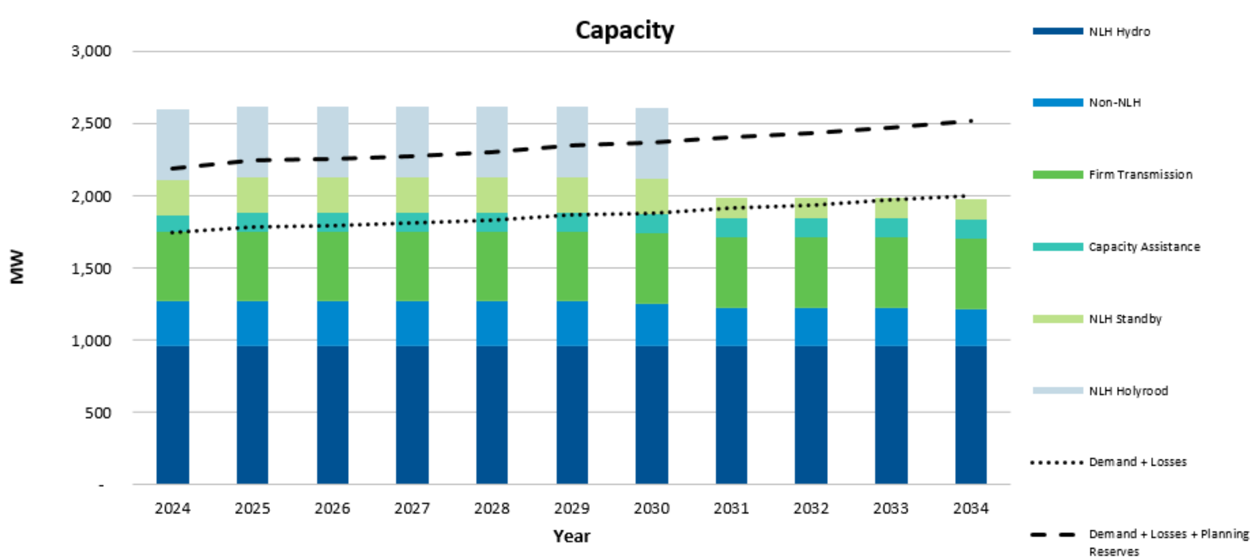


Chart 2: Island Capacity – Reference Case Load Forecast[20]

[19] A LIL bipole EqFOR of 5% was assumed to determine the planning reserve amount shown in this figure. This is further discussed in Attachment 1 to Appendix B.
[20] A LIL bipole EqFOR of 5% was assumed to determine the planning reserve amount shown in this figure. This is further discussed in Attachment 1 to Appendix B.

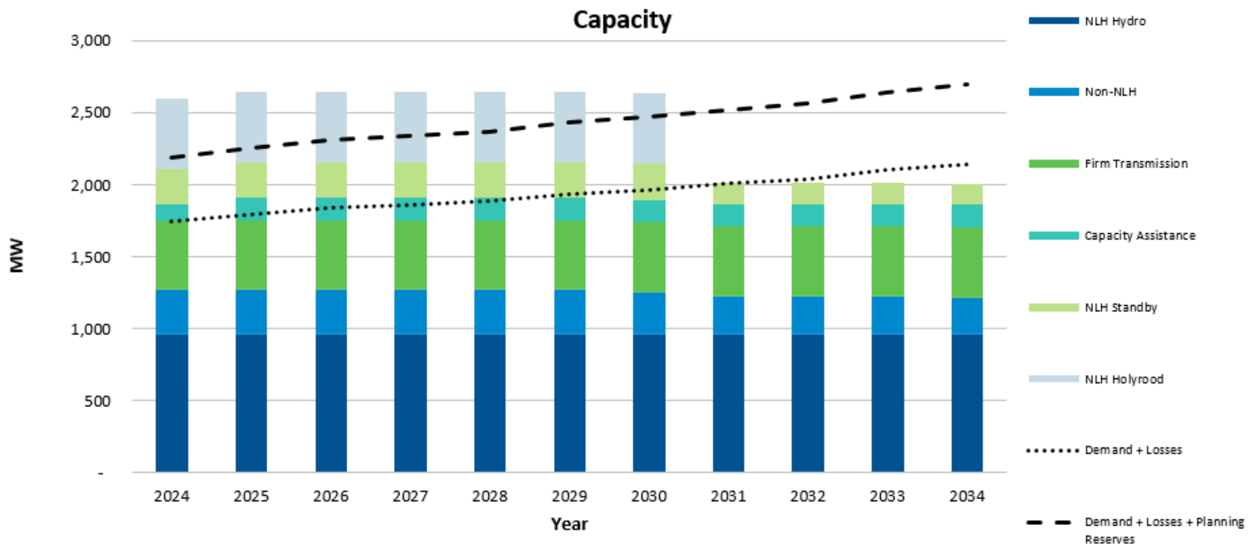


Chart 3: Island Capacity – Accelerated Decarbonization Load Forecast[21]

2.2 Labrador Interconnected System

The capacity load resource balances for each year in the planning horizon for the three Labrador Interconnected System load forecast scenarios (Reference Case, Medium Growth, and High Growth) are provided in Chart 4. In each chart, resources are identified by stacked columns and load (including losses) for each of the load forecast scenarios is represented by dotted lines.

As demonstrated in Chart 4, existing resources that supply the Labrador Interconnected System capacity requirements are sufficient to meet the Reference Case requirements; however, additional capacity resources would be required to meet the industrial Medium and High Growth requirements that have been identified through the *NAP* process.

[21] A LIL bipole EqFOR of 5% was assumed to determine the planning reserve amount shown in this figure. This is further discussed in Attachment 1 to Appendix B.

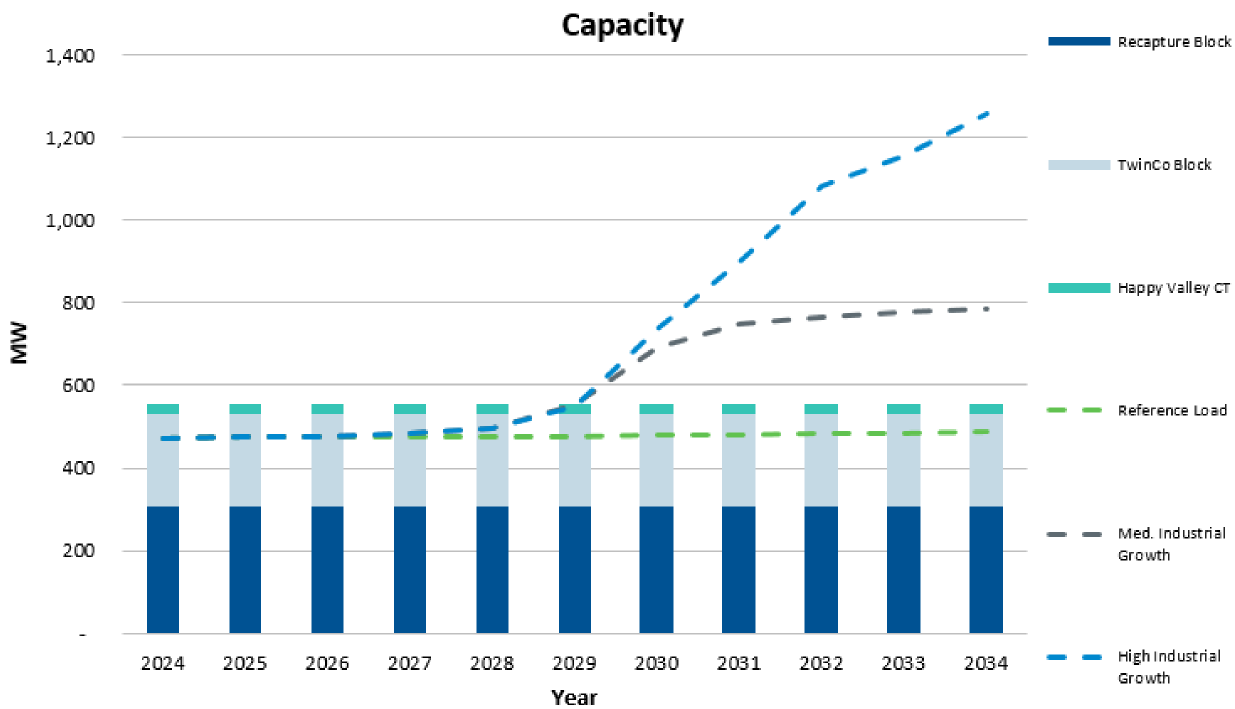


Chart 4: Labrador Capacity – All Load Forecast Scenarios[22]

For the Labrador Interconnected System, reserves are not required since generation is deemed highly reliable. The load in Labrador is served by Churchill Falls through the Recapture and TwinCo Blocks, totalling 525 MW of the 5,400 MW plant capacity. These contracts hold the highest priority of loads to be served from Churchill Falls; as such, multiple contingency events would have to occur resulting in almost total loss of all units before Hydro's Labrador load is affected. Therefore, from a planning perspective, the Recapture and TwinCo Blocks are considered a highly reliable source of supply for the Labrador Interconnected System and reserves are not needed as long as the demand remains below the capacity and energy provided by the Recapture and TwinCo Blocks. The transmission system in Labrador does have limitations, particularly during transmission equipment outages, which can have an impact on Hydro's ability to serve customers despite the reliability of generation. Transmission requirements for the Labrador Interconnected System are outside the scope of this study.

If the Labrador load materializes, it could result in the use of Muskrat Falls to serve local load requirements, reducing the ability to serve the Island, which will in turn drive a need for additional incremental additions on the Island. This possibility was not considered in this analysis, as it would drive

[22] Load is inclusive of losses.

the need for incremental additions on the Island well beyond the requirement identified in Section 2.1. Therefore, for this analysis, it is assumed that industrial load growth requirements in Labrador would have to be met by new generation sources in Labrador, as the demand exceeds the supply from the existing Recapture and TwinCo Blocks and Muskrat Falls is assumed to be delivering to only the Island Interconnected System. Should significant load growth driven by industrial need occur on the Labrador Interconnected System, there may be a requirement to develop Labrador-specific planning criteria in the future.

3.0 Firm Energy Requirements

As per the firm energy methodology discussed in Appendix B, Sections 3.1 and 3.2 provide an overview of the Island and Labrador Interconnected Systems firm energy requirements over the study period.

3.1 Island Interconnected System

The firm energy load resource balances for each year in the planning horizon for the three Island Interconnected System load scenarios—Slow Decarbonization, Reference Case, and Accelerated Decarbonization are provided in Chart 5 to Chart 7.

In each chart, the existing resources are identified by stacked columns and load (including losses) for each load forecast scenario is represented by the dashed line. The stacked columns are grouped into four main categories, which include the following:

1) **NLH Hydro**: Includes energy from the following Hydro-owned hydroelectric facilities: Bay d'Espoir, Cat Arm, Granite Canal, Hinds Lake, Paradise River, Upper Salmon, and additional small-hydro facilities.

2) **Non-NLH**: Includes energy from Newfoundland Power hydro resources, hydroelectric facilities at Deer Lake and Exploits, and other NUGS such as CBPP Co-Gen and the wind farms in St. Lawrence and Fermeuse.

3) **Firm Transmission**: Includes firm energy from the LIL that is sunk on the Island. The firm contractual commitment to Nova Scotia is not included in this amount as it is met by Muskrat Falls generation and exported via the Maritime Link.

4) **NLH Holyrood**: Includes energy from the Holyrood TGS, which is assumed retired in 2030.[23]

Consistent amongst all load forecast scenarios, once the Holyrood TGS retires in 2030, the Island Interconnected System will no longer meet its firm energy criteria without expansion.

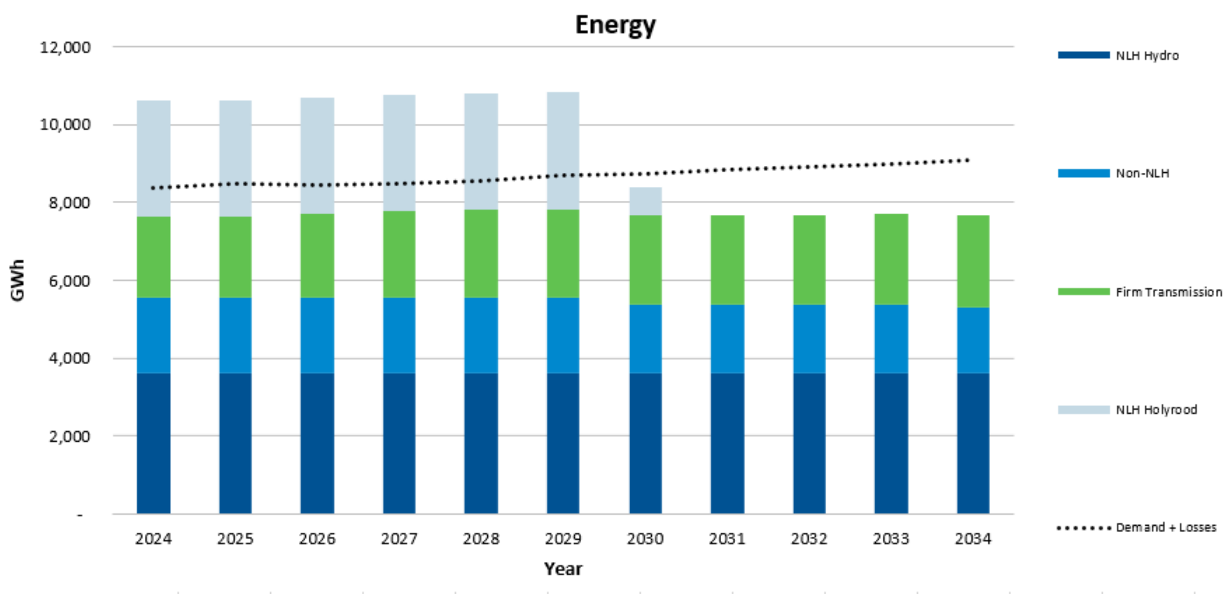


Chart 5: Island Firm Energy – Slow Decarbonization Load Forecast

[23] As discussed in the Resource Plan Overview, the units at the Holyrood TGS, Hardwoods GT, and Stephenville GT shall remain available through the Bridging Period until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.

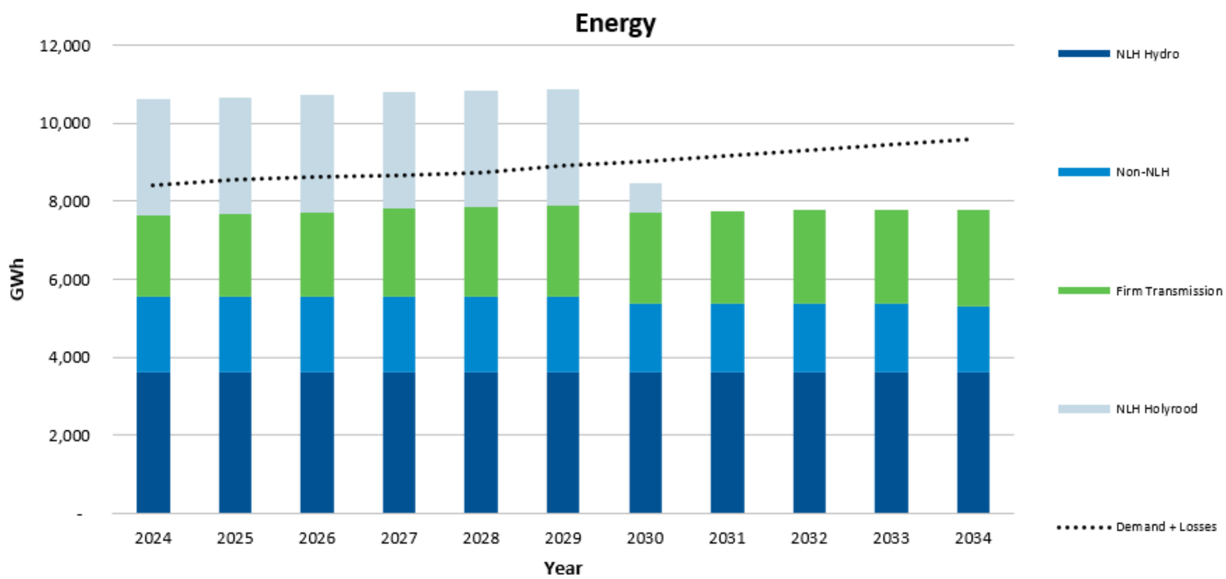


Chart 6: Island Firm Energy – Reference Case Load Forecast

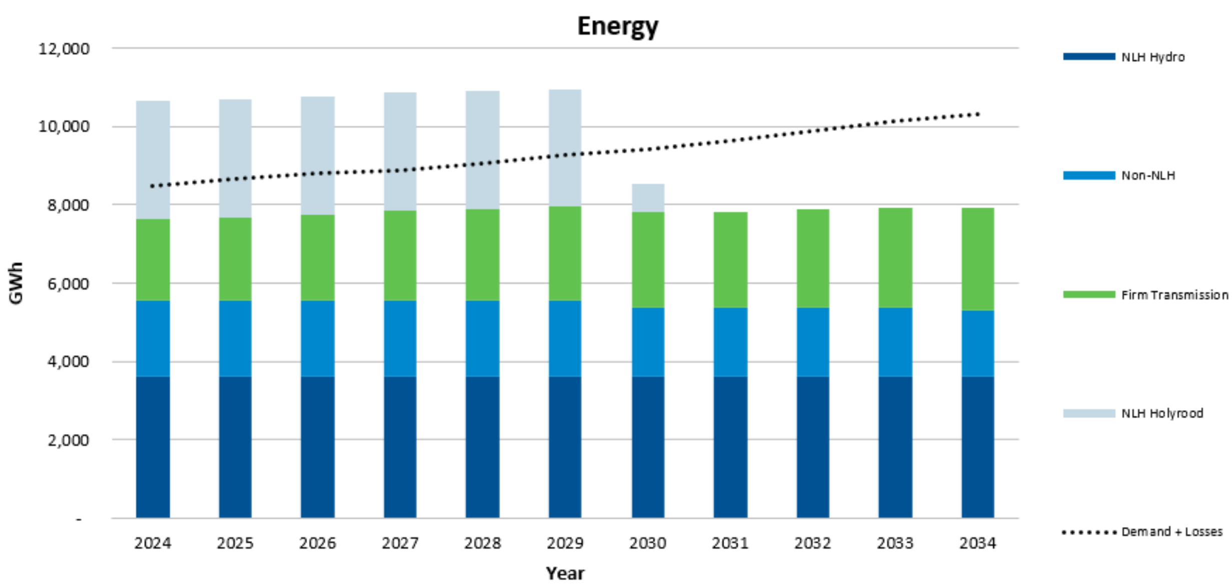


Chart 7: Island Firm Energy – Accelerated Decarbonization Load Forecast

The LIL firm energy deliveries differ depending on the load forecast scenario. This is because as Island load increases, the amount of firm energy that the LIL can supply to the Island increases slightly. Under normal system conditions, the operational relationship between LIL flow, Island Interconnected System demand, and Maritime Link flow to protect against UFLS has an impact on the amount of energy that is able to flow from Muskrat Falls to the Island Interconnected System, which is the main driver contributing to the firm energy requirement by 2030. Under normal system conditions, the amount of energy that can flow over the LIL to the Island is limited by the interdependencies with the Maritime Link and Island load. This interdependence exists because both HVdc links must work together using Special Protection Schemes that will suddenly reduce their power flows (runbacks) in order to transiently regulate system frequency in the event a contingency occurs on the other HVdc link. This LIL-Maritime Link relationship has less of an impact on the amount of power that can be absorbed on the Island than the amount of UFLS available and would be triggered following a bipole trip. The amount of available UFLS is directly proportional to the total Island load. Chart 8 illustrates the amount of LIL energy available to serve load on the Island for the three Island Interconnected System load forecast scenarios.

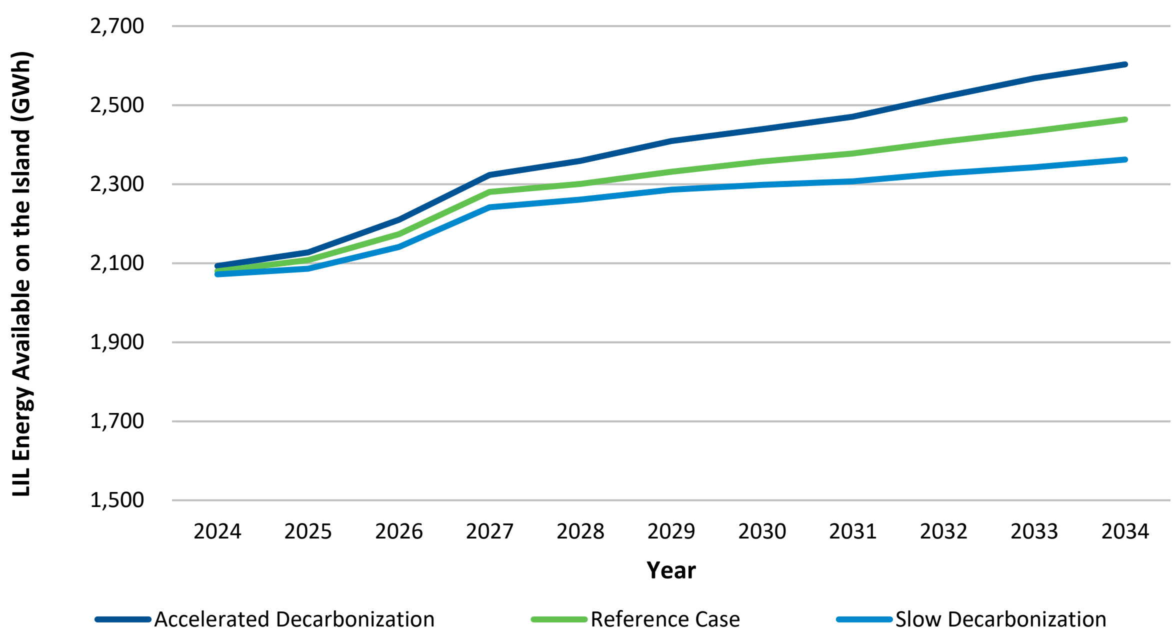


Chart 8: Annual Energy Available on the Island from the LIL

Because the operational relationship between LIL flow, Island Interconnected System demand, and Maritime Link flow to protect against UFLS restricts the amount of energy that is able to flow from Muskrat Falls to the Island Interconnected System, not all available energy can be utilized on the Island Interconnected System and therefore is expected to be exported.[24] If energy generated at Muskrat Falls

[24] The LIL energy can be exported over the Maritime Link or can potentially serve Labrador load, thus enabling more Recapture Energy for export.

is unable to be exported in the hour, it will either be banked[25] at Churchill Falls or spilled at Muskrat Falls. This risk would be highest in periods where exports over the Maritime Link are limited or Island load is low. In 2023, Hydro-Québec expressed interest in purchasing energy banked on the Churchill River system, providing Hydro an opportunity to benefit from stored energy on behalf of customers. Hydro has agreed to sell 1.7 TWh of energy banked in the Churchill River reservoir on behalf of Muskrat Falls. Hydro will continue to evaluate opportunities to optimize energy stored on the Labrador System, including short-term energy sales, where appropriate.

Thermal generation from the Holyrood TGS has historically allowed Hydro to compensate for low hydrology inflow years by increasing thermal generation as required. The Holyrood TGS will enable Hydro to ensure the firm energy requirement is met until it is planned to retire at the end of the first quarter of 2030. However, an additional firm energy source is required immediately following the retirement of the Holyrood TGS in all load forecast scenarios. While it appears that there is excess energy from 2024–2029, this is highly dependent on the number of units at the Holyrood TGS that are online each winter. Hydro continues to utilize LIL deliveries to minimize Holyrood TGS generation to the extent possible.

Additionally, the Holyrood TGS has historically provided flexibility in terms of the timing of the injection of energy into the system, such as during the winter period when additional energy is required compared to the non-winter period when the units are typically offline and less energy is required. Non-dispatchable, renewable energy options (such as wind) provide less flexibility. Should additional wind generation be integrated into the Island Interconnected System to meet firm energy needs, Hydro may have excess renewable generation in the non-winter period as energy is added to the Island Interconnected System to meet winter firm energy needs. This could lead to the potential for increased spill from hydraulic resources on the Island Interconnected System during the non-winter period and/or limit the amount of LIL energy that is brought to the Island. Storage options would increase the ability to shape generation provided by wind, and may prevent spill and/or generation curtailment; however, wind generation cannot be increased in the same way as thermal historically was.

While Hydro does not include energy produced by existing standby generation in its firm energy analysis, by 2035, thermal generation will not be able to make a significant contribution to firm energy

[25] To optimize the usage of stored water resources on the Churchill River system, energy can be stored or "banked" for future usage to efficiently manage water resources.

requirements due to environmental regulations as per the draft *CER*, which limit thermal generation to meet system energy needs in favour of renewable energy options, such as wind. Considering the life span of thermal resource options (20 years or more), this needs to be taken into consideration when making expansion decisions today. Further discussion on the draft *CER* can be found in Section 7.1.

3.2 Labrador Interconnected System

The firm energy load resource balances for each year in the planning horizon for the three Labrador Interconnected System load scenarios (Reference Case, Medium Growth, and High Growth) are provided in Chart 9.

In the chart, the existing resources are identified by stacked columns and load (including losses) for each of the load forecast scenarios is represented by dashed lines.

As demonstrated in Chart 9, existing resources that supply the Labrador Interconnected System firm energy requirements are sufficient to meet the Reference Case requirements; however, additional firm energy resources would be required to meet the industrial Medium and High Growth requirements that have been identified through the *NAP* process.

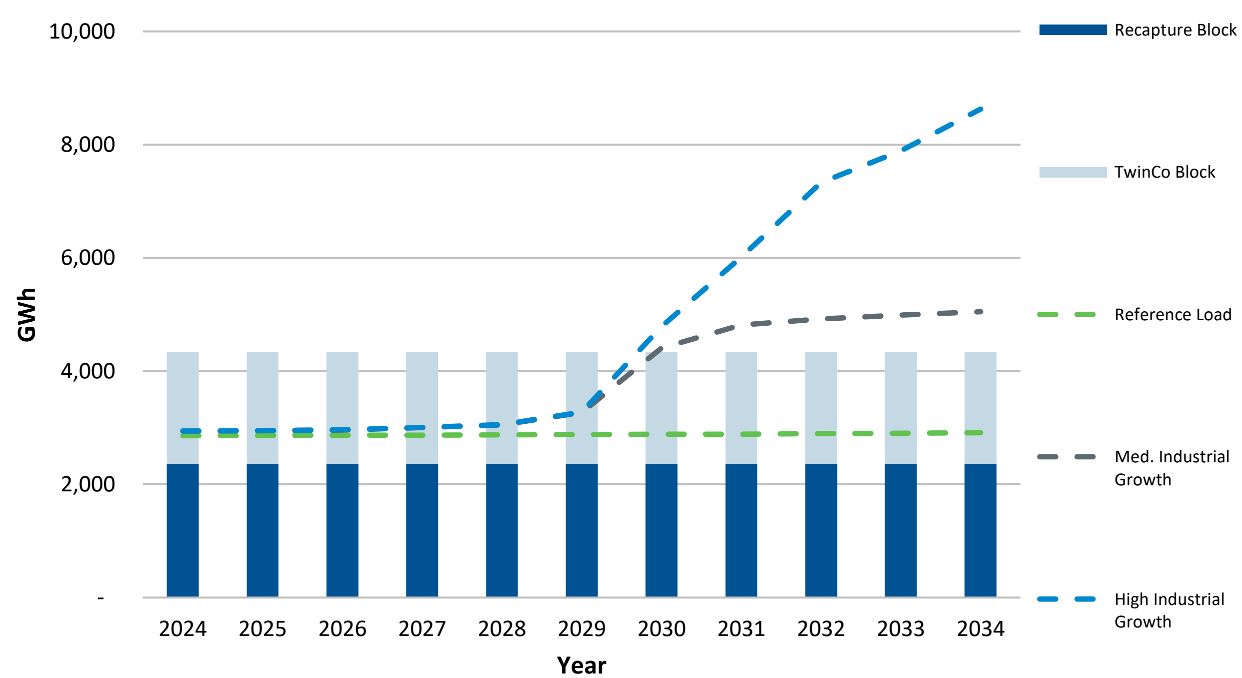


Chart 9: Labrador Firm Energy – All Load Forecast Scenarios

It is assumed in the analysis that the significant industrial load growth requirements in Labrador would have to be met by new energy sources in Labrador, as Muskrat Falls is assumed to be delivering energy to the Island Interconnected System and exporting over the Maritime Link. Due to the dynamic nature of the relationship between LIL flow, Island load, Maritime Link flow, and the evolving understanding of LIL reliability, no energy from Muskrat Falls is assumed available to meet potential Labrador industrial load growth at this time. In addition, there is potential for the industrial customers (or applicants if not already a customer), to choose to self-supply all or a portion of their energy requirements, which will have to be addressed between the industrial customer and Hydro as part of studying their interconnection requirements. The industrial applicant will also have to ensure any provincial or legislative requirements are met when considering the addition of generation.

4.0 Expansion Resource Options Under Consideration

The resource planning process identifies when incremental resources are required and which resource options fulfill Hydro's mandate of providing reliable electricity in an environmentally responsible manner at the lowest possible cost, by selecting the optimum resource mix from the portfolio of available resource options. This section provides a project description, project-specific potential issues and risks, and an AACE Class 5[26] estimate for the alternatives considered to fulfill resource requirements. All project costs included in the Expansion Model have been escalated to 2023 dollars.

As announced in the 2024 federal budget, some projects may qualify for Investment Tax Credits, which are available to provincial Crown utilities. The Government of Canada announced its continued commitment to over $160 billion in investments, including a suite of major economic Investment Tax Credits aimed to attract investment through $93 billion in incentives by 2034–2035 (e.g., a 15% refundable tax credit rate for eligible investments in new equipment or refurbishment) as well as at least $20 billion from the Canada Infrastructure Bank to build major clean electricity and clean growth infrastructure projects.[27]

[26] AACE Class 5 cost estimate is an estimate based on conceptual documentation. The accuracy of the cost estimate is estimated to be between 50% less to 100% more of the estimated cost.
[27] "Budget 2024: Fairness for Every Generation," Government of Canada, April 16, 2024. https://budget.canada.ca/2024/report-rapport/budget-2024.pdf

The following resource types are currently being considered or are being closely monitored by Hydro as potential future alternatives.[28] Specific resource options included in the current Expansion Plan modelling process are indicated in parentheses:

- Demand-side measures were incorporated into the development of the 2023 load forecast, prior to assessing supply-side options:
  - ECDM; and
  - Capacity Assistance; and
- Hydroelectric generation:
  - Additional units at existing facilities (Bay d'Espoir Unit 8 and Cat Arm Unit 3);
  - New facilities (Island Pond, Round Pond, Portland Creek); and
  - Incremental capacity/efficiency potential from existing units; and
- Thermal generation:
  - SCCTs (three CTs);[29] and
- Wind generation (generic 100 MW wind farm);[30] and
- Battery storage technology:[31]
  - Short-Duration BESS (50 MW batteries); and
  - Long-Duration BESS; and
- Solar generation (20 MW solar farm);[32]
- Market purchases;

[28] In line with legislation and Hydro's internal governance process, capital projects would be subject to the approval of the Board and Hydro's Board of Directors, as required.
[29] This analysis was conducted based on the characteristics of an LM6000 unit.
[30] Specific locations for the wind generation was not included in the model.
[31] Specific locations for battery storage was not included in the model.
[32] Specific locations for solar generation was not included in the model.

- Pumped storage:
  - Potential for upgrades to existing hydro facilities; and
  - New facilities at greenfield sites; and
- Renewal of existing PPAs.

As some of these resource options are undergoing further study, and/or the technology has not yet matured, Table 1 summarizes the resource options that were included in the Expansion Model, including the costs associated with each resource option per unit of firm or dependable capacity and the levelized cost of energy. As information continues to be gathered on potential resource options, it will be included in the Expansion Model for future analysis.

Table 1: Summary of Resource Options and Cost Estimates[33]

Resource Type	Resource	Rated Capacity (MW)	Cost of (Rated) Capacity ($/kW)	Firm Capacity (MW)	Cost of (Firm) Capacity ($/kW)	Average Energy (GWh)	Levelized Cost of Energy ($/MWh)	Fixed O&M ($/kW/yr.)	Variable O&M ($/MWh)
Hydro	BDE Unit 8	154.4	3,345	154.4	3,345	0	N/A	16	8
	CAT Unit 3	68.2	4,662	68.2	4,662	0	N/A	24	8
	Island Pond	36	15,570	36	15,570	186	213	121	8
	Round Pond	18	19,055	18	19,055	139	176	144	8
	Portland Creek	23	15,746	23	15,746	142	182	119	8
Thermal	3 CTs	141.6	3,204	141.6	3,204	35[34]	N/A	20	6
Wind[35]	100 MW	100	2,082	22	9,464	350	65	48	-
Battery[36]	20 MW[37]	20	2,740	12	4,566	0	N/A	110	-
	50 MW	50	2,221	30[38]	3,701	0	N/A	89	-
Solar[39]	20 MW	20	1,659	0	N/A	35	87	26	-
Proxy Capacity[40]	50 MW	50	10,000	50	10,000	0	N/A	20	6

33 All costs are in 2023 CDN. Presentation of cost estimates may vary as a result of the differences in software assumptions used by PLEXOS and Hydro's capital budgeting software.
34 Determined based on the efficiency of the LM6000 units and burning 10 days of fuel in storage.
35 Installed wind capacity represents the capacity for the largest single installation (100 MW) included in the model.
36 Installed battery capacities represent the capacity for each single installation option (50 MW) included in the model.
37 The 20 MW BESS option was ultimately removed from the Expansion Model to simplify the analysis.
38 As a base assumption, batteries were assumed to have an ELCC of 60%; however, sensitivities of 40% and 80% were tested.
39 Installed solar capacity represents the capacity for the largest single installation (20 MW) included in the model.
40 A proxy capacity resource option representing 50 MW of CT generation was used as a placeholder capacity option.

As Table 1 demonstrates, the capacity costs of the three small hydro resource options (Island Pond, Round Pond, and Portland Creek) are significantly higher than other capacity resources. Hydro believes that there could be other resource options (such as another CT) available for a much lower cost; however, additional study is required to define these resource options. A 50 MW proxy capacity resource option was defined in the model as a placeholder with a somewhat arbitrary cost that would ensure it was selected by the model ahead of the aforementioned costly hydro options. This resource was defined as a thermal resource in the model with associated emissions; however, further study is required to identify all possible resource options.

In 2023, Hydro engaged Daymark to compare the costs that Hydro used for each resource option included in the Expansion Model against three industry benchmarks to determine whether the capital cost and operating cost assumptions are generally consistent. Daymark concluded that the capital cost, fixed O&M costs, and variable O&M costs that Hydro uses as a basis for its expansion planning activities are reasonable in comparison to industry benchmarks. Daymark included the following recommendations to ensure that technologies are compared to one another as accurately as possible:

- The capital costs for the two larger hydroelectric options were low in comparison to both benchmarks. While Daymark acknowledges that there is a high degree of site-specificity, especially given that these are existing projects, Daymark urges Hydro to consider substantially higher estimate for this parameter to better understand the sensitivity of the Expansion Plan to these cost estimates.[41]
- The capital cost for the CT was high in comparison to industry benchmarks. Daymark recommends that Hydro consider ensuring all cost estimates carry the same level of design estimates. Overly burdening one supply resource may tend to skew results leading to a sub-optimal Expansion Plan. Hydro has confirmed that the capital costs will be refined for any future build applications.[42]

Daymark's review of Hydro's cost estimates, including benchmarking exercises and recommendations, is provided as Attachment 1 to this Appendix.

[41] This recommendation was addressed within this filing by applying a sensitivity to select expansion plan scenarios that increased the hydroelectric generation capital costs by an additional 50%.
[42] AACE Class 3 cost estimates are being conducted to support build applications.

A description of the expansion resource options under consideration are included in Sections 4.1 to 4.10.

4.1 ECDM

ECDM is crucial for optimizing Newfoundland and Labrador's electrical system, particularly as the region faces increasing energy and capacity requirements. Cost-effective ECDM programs directly benefit customers by reducing energy consumption (resulting in cost savings for customers) while also reducing the demand for energy and capacity on the system, thereby reducing the investment required to meet customer electricity requirements. By managing and reducing energy consumption and customer demand, ECDM programming serves to enhance system efficiency and mitigate the need for new supply resources; therefore, it is a priority for Hydro as it plans for the future of the electrical system.

The NL Utilities jointly deliver ECDM programming on the Island Interconnected System under the takeCHARGE partnership. In 2023, takeCHARGE programming achieved combined savings of more than 13 MW and 32 GWh on the Island Interconnected System.[43] Programming offered to customers under takeCHARGE must be shown to be cost effective.[44] An ECDM program (or portfolio of programs) is determined to be cost effective if the benefits from that program are greater than the costs of delivering that programming. Benefits from ECDM include avoided system costs (the marginal value of energy and capacity), which must be greater than the cost of implementing that same program.[45] In this regard, cost-effective ECDM programming represents a source of supply for Hydro that is less costly than its next supply option.

4.1.1 Electrification Programming

Hydro ensures the energy and capacity benefits from utility and customer ECDM activities, such as forecast impacts of takeCHARGE programming, utility demand response programming for EVs,[46] and customer conversions to heat pumps for space heating are all reflected in its load forecast. For the 2023

[43] Combined results from the "2023 Conservation, Demand Management and Electrification Report," Newfoundland Power Inc., April 17, 2024, sec. 2.2, Table 1, p. 3 and Hydro's 2023 results for the Island Interconnected System only.
[44] In *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 18(2016), Board of Commissioners of Public Utilities, June 8, 2016, the Board approved the use of the TRC Test and the PAC Test to demonstrate cost effectiveness.
[45] In the case of the PAC Test specifically. The TRC Test also considers supply side benefits in addition to participant costs and program costs.
[46] Hydro has assumed that it will be able to achieve 50% demand management for new light-duty EV charging demand on the system, shifting 50% of EV charging outside of the peak demand period. Newfoundland Power's ongoing EV Load Management Pilot Program, which studies various methods to encourage consumers to manage their demand during peak periods, will help inform how this target is achieved.

Load Forecast update, an estimate of energy savings through utility conservation programs, as forecast by takeCHARGE, was developed. This estimate was used for all three load forecast scenarios and equates to cumulative residential and commercial energy savings of approximately 140 GWh by 2034.

Hydro is actively monitoring electrification trends in the province and taking steps to manage the resulting electrical system impacts. Monitoring these programs helps refine demand management strategies and informs ongoing customer education to help mitigate the cost impacts from electrification. The data gathered also supports Hydro's load forecasting, which is crucial for planning and aligning future energy supplies with demand.

As government policy and customer trends continue to advance electrification in Newfoundland and Labrador, Hydro is seeking opportunities for beneficial electrification, where benefits associated with new energy sales are maximized and customer behaviours are influenced to minimize system costs. For example, changes were made within GNL's Oil to Electric Incentive Program, which encourages participants to select more efficient heat pumps rather than resistance heat technologies, thereby lowering the system impact of the transition away from oil space heating. Hydro also supports Newfoundland Power's Electric Vehicle Load Management Pilot Project, [47] as shifting EV charging load to off-peak hours is critical to limiting system impacts from the electrification of the transportation sector. The results of this pilot will help inform ECDM strategies and future programming as it relates to EVs.

For this analysis, Hydro has assumed that it will be able to achieve 50% demand management for new EV charging demand on the system, shifting 50% of EV charging outside of the peak demand period. Newfoundland Power's ongoing Electric Vehicle Load Management Pilot Project, which studies various methods to encourage consumers to manage their demand during peak periods, will help inform how to best achieve this target.

[47] "Electric Vehicle Load Management Pilot Project," takeCHARGE. https://takechargenl.ca/evs/electric-vehicle-load-management-pilot-program/

4.1.2 Future ECDM Programming

Every five years, the NL Utilities jointly commission a study to evaluate the potential for ECDM in the province, with the most recent study completed by Dunsky in 2019.[48] In 2023, the NL Utilities contracted Posterity to undertake a new CDM Potential Study to assess the technical, economic, and achievable potential for ECDM activities on the Island Interconnected System from 2025 to 2040. The study will conclude in 2024 and will be used by the NL Utilities to develop the next multi-year ECDM plan.

Certain jurisdictions utilize electricity rate structures to influence consumer behaviour and mitigate system demand. TOU Rates utilize varying electricity rates at different times of the day to encourage customers to shift energy usage to off-peak times, whereas programs such as CPP provide similar incentives to manage demand during critical peak periods. These dynamic rate programs aim to influence the "shape" (i.e., the timing of the highest demand each day) of the demand on the system by spreading electricity usage over multiple hours and reducing the size of the peak demand on the system. The effectiveness of such programs is highly dependent on the shape of the load profile on the system.

As new loads, such as EV charging, become more prevalent on the system, Hydro expects the shape of demand during peak days will change, potentially resulting in a larger evening peak. By studying the impacts that these loads have on the system, Hydro will be able to evaluate whether dynamic rate structures present a cost-effective way to manage demand and energy usage and shift loads into the overnight period.

Like other ECDM initiatives, programs such as TOU Rates and CPP require investment, such as the implementation of smart meters to enable real-time monitoring of electricity usage and administrative costs. To date, these programs have not represented cost-effective, technically viable options to manage system demand[49] when compared to lower-cost alternatives in Hydro's supply stack. In its most recent study, Dunsky cited that timeline for cost-effectiveness was within the 2024 Resource Plan study period.

---

[48] "Newfoundland and Labrador Conservation Potential Study (2020–2034)," Dunsky, filed as "Application for Approvals Required to Execute Programming Identified in the Electrification, Conservation and Demand Management Plan 2021–2025," Newfoundland and Labrador Hydro, rev. July 8, 2021 (originally filed June 16, 2021), sch. 3, sch. C. http://www.pub.nl.ca/applications/2021/NLH2021Capital/NLH2021Capital_SUPP_ExecuteProgram/apps/From%20NLH%20-%20Approvals%20Required%20to%20Execute%20Programming%20Identified%20in%20the%20Electrification%20Conservation%20and%20Demand%20Management%20Plan%202021-2025%20-%20REVISION%201%20-%202021-07-08.PDF

[49] As per "Newfoundland and Labrador Conservation Potential Study (2020–2034)," Dunsky, filed as "Application for Approvals Required to Execute Programming Identified in the Electrification, Conservation and Demand Management Plan 2021–2025," Newfoundland and Labrador Hydro, rev. July 8, 2021 (originally filed June 16, 2021), sch. 3, sch. C, the Dunsky Study shows that dynamic rates are not expected to become cost effective until the 2030s.

The new ECDM Potential Study will include an update on this analysis. Once smart metering technology is demonstrated to be least-cost for customers, Hydro anticipates incorporating this technology as soon as feasible to enable future dynamic rate structures.

Hydro will continue to evaluate rate design programs like TOU Rates and CPP against the next options in the supply stack to determine when and if these programs represent a cost-effective solution to meet growing demand on the system.

4.2 Capacity Assistance

Hydro continues to support system requirements by partnering with large industrial and commercial customers through CAAs to curtail electricity usage during peak times. These agreements allow the utilization of customer-owned generation, such as generation from CBPP, to support the system when required. Through strategic partnerships with other large electricity customers, Hydro has accounted for over 130 MW of capacity assistance in its modelling, which represents approximately 7.5% of Island Interconnected System coincident system peak in 2025. This level of capacity assistance provides an equivalent system benefit to that of a large supply addition, such as a CT. Cost-effective capacity assistance has enabled Hydro to delay the implementation of new supply and will continue to play an active role in minimizing the investment required to meet demand on the system. In addition, Hydro is committed to seeking third-party support for additional capacity options.

4.3 Hydroelectric Generation

In 2022, Hydro engaged AtkinsRéalis[50] to evaluate island hydroelectric generation expansion alternatives.[51] This study builds on 2018 work presented in previous *RRA Study Review* filings by screening and ranking generation alternatives according to a pre-established set of criteria. The primary objective was to determine the gap in project planning maturity for a suite of prospects by comparing existing documentation against the requirements for completion of Front-End Planning. A secondary objective was the identification of technical deficiencies and optimization opportunities through a review of existing documentation by the engineering disciplines (e.g., civil, electrical, mechanical, etc.).

[50] Formally known as SNC-Lavalin Group Inc.
[51] For additional information, please refer to "Evaluation of Island Hydroelectric Generation Expansion Alternatives," SNC-Lavalin Group Inc., October 21, 2022, filed as Attachment 4 to Hydro's response to PUB-NLH-288, filed as part of the *RRA Study Review*.

A key assumption in this study was that project planning, screening and ranking methods must be consistent with industry practice for large capital projects (>$50 million). Such industry practice includes key decision point process for large capital projects, AACE Recommended Practices, Heavy Civil Project Execution Standard, and other internal AtkinsRéalis experience and best practices. It was also assumed that the study should be conducted in keeping with the recommendations from Justice Leblanc from the *Muskrat Falls Inquiry*.[52]

After a data and documentation review, including the assessment of previous costs and schedules and escalation of costs to year-end 2022, the hydraulic generation alternatives were screened and ranked against criteria such as capacity, cost, environmental impacts, market conditions, etc. The resulting ranking in order of preference of prospective hydroelectric generation expansion alternatives is:

1) Addition of a new unit (Unit 8) in Bay d'Espoir (154 MW)
2) Addition of a new unit (Unit 3) in Cat Arm (68.4 MW)
3) Island Pond Development (36 MW)
4) Round Pond Development (18 MW)
5) Portland Creek Development (23 MW)

The Exploits River Development was not included in the recommendation due to environmental and public acceptance concerns. This is discussed in more detail in Section 4.3.6.

A brief project description of each hydraulic option follows.

4.3.1 Bay d'Espoir Unit 8[53]

The existing development at Bay d'Espoir consists of six 76.5 MW units in Powerhouse 1 and one 154.4 MW unit in Powerhouse 2. Bay d'Espoir Unit 8 is a proposed 154.4 MW unit located in Powerhouse 2 next to the existing Unit 7. This project would provide capacity to the system. The rock excavation for the second unit and downstream portion of the draft tube was constructed in 1977 when

---

[52] Honourable Richard D. LeBlanc, "Muskrat Falls: A Misguided Project," *Commission of Inquiry Respecting the Muskrat Falls Project*, March 5, 2020, vol. 1, Key Recommendations, p. 61. https://www.muskratfallsinquiry.ca/files/Volume-1-Executive-Summary-Key-Findings-and-Recommendations-FINAL.pdf
[53] For additional information, please refer to "Evaluation of Island Hydroelectric Generation Expansion Alternatives," SNC-Lavalin Group Inc., October 21, 2022, filed as Attachment 4 to Hydro's response to PUB-NLH-288, filed as part of the *RRA Study Review*.

Powerhouse 1 was commissioned. As this project would share the existing annual water supply from the existing watershed, there is no direct increased energy production associated with this project. However, there is a potential benefit of the additional unit being able to turbine water that would otherwise be spilled.[54] Additionally, this unit would likely be more efficient and would therefore be used preferentially over older units, which has associated energy benefits. Further study would be required to define these potential energy benefits.

Bay d'Espoir Unit 8 would interconnect to the system via the construction of a 1.5 km 230 kV line from the Unit 8 step-up transformer to Bay d'Espoir Terminal Station 2. The cost of this transmission upgrade is included in the cost estimate.

4.3.2 Cat Arm Unit 3[55]

The existing development at Cat Arm consists of two 68.5 MW units. Cat Arm Unit 3 would increase the generating capacity of the existing Cat Arm facility by installing an additional 68.5 MW generating unit. While there is no direct increased energy production associated with this project, there could likely be incremental energy production associated with minimizing spill energy.[56] In addition, this unit would likely be more efficient and would be used preferentially over the two older units, which has associated energy benefits. Further study is required to define these potential energy benefits. The project would consist of a newly constructed extension to the south side of the existing powerhouse; a permanent access road including a bridge across the tailrace to maintain access to the transformer yard; construction of a penstock; and new generating unit.

Hydro does not anticipate any major transmission upgrades associated with the addition of this unit.

4.3.3 Island Pond Development[57]

The prospective Island Pond Development is located in South Central Newfoundland within the existing watershed of the Bay d'Espoir development (on the North Salmon River) would provide a firm capacity

[54] While there is an average benefit due to the reduction in spill, there is no firm energy benefit associated with the eighth unit. This is because in a dry sequence, the reservoir would not be in a spill situation.
[55] For additional information, please refer to "Evaluation of Island Hydroelectric Generation Expansion Alternatives," SNC-Lavalin Group Inc., October 21, 2022, filed as Attachment 4 to Hydro's response to PUB-NLH-288, filed as part of the *RRA Study Review*.
[56] While there is an average benefit due to the reduction in spill, there is no firm energy benefit associated with the third unit. This is because in a dry sequence, the reservoir would not be in a spill situation.
[57] For additional information, please refer to "Evaluation of Island Hydroelectric Generation Expansion Alternatives," SNC-Lavalin, October 21, 2022, filed as Attachment 4 to Hydro's response to PUB-NLH-288, filed as part of the *RRA Study Review*.

of 36 MW. The project would utilize approximately 25 m of net head between the existing Meelpaeg Reservoir and Crooked Lake to produce an annual firm and average energy capability of 172 GWh and 186 GWh, respectively. Electricity would be produced by one 36 MW turbine and generator assembly.

To complete the interconnection with the existing system, a 18 km long, 69 kV class transmission line and a new terminal station would be required.

4.3.4 Round Pond Development[58]

The prospective Round Pond Development is located in South Central Newfoundland within the existing watershed of the Bay d'Espoir development (between Godaleich Pond and Long Pond Reservoir) and would provide a firm capacity of 18 MW. The project would utilize the available net head between the existing Godaleich Pond and Long Pond Reservoir to produce an annual firm and average energy capability of 108 GWh and 139 GWh, respectively. Electricity would be produced by a single, 18 MW generating unit.

To complete the interconnection with the existing system, a 44 km long, 69 kV transmission line would be required to connect the existing Bay d'Espoir Terminal Station 2.

4.3.5 Portland Creek Development[59]

The prospective Portland Creek Hydroelectric Development is located on Main Port Brook (near Daniel's Harbour on the west side of the Great Northern Peninsula) and would provide a firm capacity of 23 MW. The project would produce an annual firm and average energy capability of 99 GWh and 142 GWh, respectively.

To complete the interconnection with the existing system, the construction of a 25.5 km 66 kV class transmission line is required to connect to the existing Peter's Barren Terminal Station.

[58] For additional information, see "Evaluation of Island Hydroelectric Generation Expansion Alternatives," SNC-Lavalin, October 21, 2022, filed as Attachment 4 to Hydro's response to PUB-NLH-288, filed as part of the *RRA Study Review*.
[59] For additional information, see "Evaluation of Island Hydroelectric Generation Expansion Alternatives," SNC-Lavalin, October 21, 2022, filed as Attachment 4 to Hydro's response to PUB-NLH-288, filed as part of the *RRA Study Review*.

4.3.6 Exploits River Development[60]

The prospective Exploits River Development consists of the construction of two subprojects on the Exploits River:

1) Red Indian Falls: Construction of a 42 MW hydroelectric generating facility 20 km upstream of the Town of Badger; and
2) Badger Chute: Construction of a 24 MW hydroelectric generating facility 7 km downstream of the Town of Badger.

It was noted in the 2018 Filing that the development of Badger Chute has the potential to increase ice formation and elevate the risk of flooding for the Town of Badger. However, the construction of Red Indian Falls would, conversely, reduce (if not eliminate) the flooding problem. For this reason, Badger Chute would need to be completed in conjunction with (or closely following on the completion of) Red Indian Falls. This condition would likely further complicate public acceptance of these developments.

Both subprojects have been studied at a high level and suggest that both projects are “reasonably viable”, but with the following caveat:

> There are significant concerns surrounding the potential environmental, socioeconomic and archeological impacts associated with these developments. The full extent of these impacts and their associated mitigation costs will need to be understood prior to the completion of an accurate assessment. It is uncertain at this time as to whether or not either of these alternatives would receive approval as part of the Environmental Assessment Process.[61]

While it is likely that many of the issues can be mitigated, it is more likely that other alternatives on the Island present viable alternatives with considerably less environmental impact and an improved probability of public acceptance. However, future development of these resources could be acceptable as part of a renewable energy strategy or as other generation options are built or economic analysis deems them unviable to develop.

[60] For additional information, see “Evaluation of Island Hydroelectric Generation Expansion Alternatives,” SNC-Lavalin, October 21, 2022, p. C-83, filed as Attachment 4 to Hydro’s response to PUB-NLH-288, filed as part of the *RRA Study Review*.
[61] “Evaluation of Island Hydroelectric Generation Expansion Alternatives,” SNC-Lavalin, October 21, 2022, filed as Attachment 4 to Hydro’s response to PUB-NLH-288, filed as part of the *RRA Study Review*.

4.3.7 Incremental Capacity/Efficiency Potential

Hydro intends to identify any opportunities to uprate units in Hydro's fleet on the Island Interconnected System to assess the feasibility of incremental capacity and/or efficiency. The detailed scope of work of this study in it's entirety is still under development; however Bay d'Espoir Unit 7, was selected first to coincide with the Unit 7 Condition Assessment (2023) – Bay d'Espoir project.[62] The outcome of this study is discussed in Section 4.3.7.1.

4.3.7.1 Bay d'Espoir Unit 7 Uprate Study

This study assessed the possibility of uprating Bay d'Espoir Unit 7 as part of identifying opportunities to uprate units in Hydro's existing fleet on the Island Interconnected System. This unit will require an overhaul in the near future due to its age and condition and the objective of this study was to provide additional insight into the feasibility of a future capacity increase for Bay d'Espoir Unit 7 based on a review of previous uprate studies. The Bay d'Espoir Unit 7 Uprate Study assumed that the existing water flow at the headrace level at rated output is maintained, major embedded components are not replaced, and new equipment requires no modifications to concrete or powerhouse structures, including the overhead crane.

Three scenarios were considered:

1) Efficiency Improvements Only: a runner efficiency increase of 2% was assumed across the operating range;
2) Efficiency Improvements and Capacity Increase: utilizing additional hydraulic capacity available in the system to achieve more significant increases in generating capacity than would be possible through efficiency improvements alone; and
3) Replace-in-Place: minor interventions, rehabilitation, or like-for-like replacement.

It was determined that upgrading Bay d'Espoir Unit 7 from 154 MW to 174 MW is feasible with an investment of approximately $18 to $28 million. Additionally, there is potential to upgrade to up to 180 MW with the existing water passage and embedded components; however, further study is required. Ultimately, the uprate analysis for Bay d'Espoir Unit 7 should be made in combination with the

[62] "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022, vol. II, proj. 23. http://pub.nl.ca/applications/NLH2023Capital/apps/From%20NLH%20-%202023%20Capital%20Budget%20Application%20-%20Volume%20II%20-%202022-07-13.PDF

addition of Bay d'Espoir Unit 8, where both units should be considered concurrently for the determination of their respective optimal capacity and design. Additional recommendations and the full Bay d'Espoir Unit 7 Uprate Study can be found in Attachment 2 to this Appendix.

4.4 CT Generation

In 2023, Hydro engaged Hatch to examine the feasibility of installing a CT as a source of fuel-fired backup generation on the Avalon.[63] The CT Options Report examined three plant sizes (150 MW, 300 MW, and 450 MW) and six potential sites located on the Northeast Avalon (Holyrood, Paddy's Pond, Sugarloaf Pond, Soldiers Pond, Bremigens Pond, and Petty Harbour Long Pond). A location on the Northeast Avalon is preferred, due to the appreciable transmission constraints that limit power flow to the Avalon. The requirement for future transmission reinforcements would be reduced if future generation supply were to be located closer to the Northeast Avalon as the main load centre. After performing a site assessment, Hatch determined Holyrood to be the recommended site. Hatch also recommended a plant capacity of 150 MW based on the current availability of fuel supply on the Island.

A SCCT was selected as the preferred option for thermal expansion on the Island Interconnected System. It is capable of fast start, has SC capabilities, and can transition to renewable fuel sources, should such fuels become widely available in the future. These units have a rated capacity of 47.2 MW; therefore, three units would be required to supply the 141.6 MW that has been defined as the resource option in the CT Options Report. Smaller units such as these are considered to be more appropriate for Hydro's system than larger units (i.e., one 150 MW unit) and would result in increased reliability benefits and operational flexibility.

The proposed *CER* are currently under development. Based on the February 2024 Public Update published by ECCC, an increase to the emissions intensity of 30 t/GWh proposed in the draft regulations is under consideration.[64] Hydro has assessed the ability of any new thermal generation resources to

[63] For additional information, refer to, "Combustion Turbine Feasibility Study," Newfoundland and Labrador Hydro, October 13, 2023.
http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/reports/From%20NLH%20-%20Combustion%20Turbine%20Feasibility%20Study%20-%202023-10-13.PDF

[64] "Clean Electricity Regulations Public Update: 'What We Heard' during consultations and directions being considered for the final regulations," Environment and Climate Change Canada, February 16, 2024, sec. 2, p. 7.
https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/clean-fuel/electricity/clean-electricity-regulations-public-update-16022024.pdf

comply with the draft *CER* and will continue to monitor the *CER* as it evolves. Further discussion on the *CER* can be found Section 7.1.

Further study of CTs as a resource option included a Fuel Market Study and the potential for a short-term CT option. Both are discussed further in Sections 4.4.1 and 4.4.2, respectively.

4.4.1 Fuel Market Study

In late 2023, Hydro contracted a Fuel Market Study, which assessed the market forecast and availability for diesel fuel, reviewed existing supply chain processes to identify risks and potential improvements, outlined critical assets along the total supply chain, and provided an outlook of alternative fuel sources. The Fuel Market Study concluded that the Canadian refining sector is facing structural and regulatory pressures that may reduce the availability of No. 2 Diesel fuel, contrasting with a more stable forecast for the U.S. refining sector. Regulatory initiatives in Canada aimed at reducing emissions will likely influence refinery operations, potentially leading to decreased production capacities by 2040, whereas U.S. refineries are expected to maintain production levels due to economic, strategic importance, and national security considerations.

The Fuel Market Study also highlights significant risks in the existing supply chain processes, including limited supplier responses to requests for proposals as well as logistical challenges in emergency fuel supply. The Fuel Market Study recommends the development of a more diverse supplier pool, enhancements in storage and inventory management, and strategic placement of fuel reserves. It also evaluated alternative fuels, noting practical limitations for hydrogen, the unsuitability of biodiesel, and logistical challenges for renewable diesel fuels, suggesting that, while some of these alternative fuels have potential, pricing, sourcing, and storage of large volumes of alternative fuels remains a challenge.

Overall, the Fuel Market Study emphasizes the need for strategic planning and adaptation to ensure a reliable fuel supply amidst evolving market and regulatory landscapes. Further assessment is needed to ensure a stable and secure supply of fuel for electricity generation and to assess the viability of CT operations beyond approximately 150 MW as feasible, cost-effective resource options. The Fuel Market Study is provided as Attachment 4 to this Appendix.

4.4.2 Supply Options in the Short-Term

In 2024, Hydro engaged Stantec to identify CT options of one or more units to provide up to 150 MW that may be readily available for an accelerated installation schedule. The availability and suitability of grey market units for use on the Island Interconnected System was the focus of this study. The CT Options Report confirmed that there are currently no suitable CTs available to enable an earlier replacement of the Holyrood TGS, the Hardwoods GT, or the Stephenville GT. The outcome of the CT Options Report is summarized in Sections 4.4.2.1 through 4.4.2.3 and provided as Attachment 3 to this Appendix.

4.4.2.1 Combustion Turbines

The CT Options Report focused on identifying available CT options of a nominal 150 MW that would be readily available for purchase and installed on an accelerated schedule. The following unit configuration was issued to vendors, as stipulated by Hydro:

- Nominal 150 MW capacity;
- Use No. 2 Diesel fuel with the ability to run on, or be converted to using, alternate fuels;
- Synchronous condensing capability;
- Fast start, with rated generation in no more than ten minutes;
- Required Balance of Plant equipment;
- BACT for emission control; and
- Units that are currently available due to cancelled/delayed projects or existing/refurbished units with low running hours/starts.

After issuing an RFI, vendors were able to locate six units. When comparing the requested configuration to the vendor offering, the units do not meet Hydro requirements for the reasons noted in Sections 4.4.2.1.1 to 4.4.2.1.4.

4.4.2.1.1 <u>Fuel Type</u>

The current units are configured to run on natural gas, which is not available in the province at this time. A conversion to run on No. 2 Diesel fuel would be required for the initial operation of the unit(s). At this time, conversion costs are unknown. As part of FEED, Hydro is investigating multiple fuel sources that could be used in the future; natural gas will be one such fuel to be investigated further.

4.4.2.1.2 Synchronous Condensing

The unit generators are not configured for synchronous condensing. Hydro has determined synchronous condensing will be required for the new facility and is based on the following requirements:

- **Increases SCLs:** there are SCL requirements to operate the LIL at specific power levels. New CTs will allow Hydro to increase the SCLs on the system without utilizing fuel during lighter load conditions. If the required SCLs are not available, there is a potential need to limit LIL imports to the Island to avoid jeopardizing performance.
- **Improved Steady State Voltage Regulation:** in the event none or one Soldiers Pond SCs is online, Hydro has limited ability to regulate voltages on the Avalon during light load conditions, which could also affect operation of the LIL. Operation of the units as SCs, to regulate voltage, will reduce the requirement to burn fuel in generation mode.
- **Improved Transient Stability:** operation of the SCs will help improve system stability by providing a better recovery from transient events, with the benefit of not having to burn fuel. In the event of an extended LIL outage, SCs could potentially allow Hydro to deliver more (cleaner) power to the Avalon from Hydro generation off the Avalon. Even with the LIL in-service, there is a requirement to dispatch Avalon generation to make the system more stable for the sudden loss of the LIL, which would require burning fuel; having new SCs would reduce this requirement.
- **Improved Frequency Regulation:** operation of the SCs will provide more inertia to the system and improve frequency stability in the event of a LIL bipole trip, without having to burn fuel. This could potentially help facilitate additional LIL imports with less reliance on the Maritime Link.
- **More Flexibility for Planning Maintenance at Soldiers Pond:** there would be less reliance on the existing Soldiers Pond SCs if the new CTs could act as a substitute and operate as SCs to strengthen the system (increase SCLs) without consuming fuel. This would provide more operational flexibility for planned or unplanned outages to the existing Soldiers Pond SCs.[65]

[65] The performance of the Soldiers Pond SCs is discussed in Hydro's Rolling 12 reports. http://pub.nl.ca/indexreportspages/12MonthRollingAverage.php

4.4.2.1.3 Balance of Plant Equipment

The identified units were not built for the Canadian market. There are potential components that do not meet CSA standards and would require review and registration. As an example, pressure vessels and fittings require a CRN.

The units are currently configured with DLE technology when burning natural gas. Generally, CTs burning No. 2 Diesel fuel, utilize water injection technology. From an environmental regulation perspective, any CT must be equipped with the BACT. Further investigation would be required to confirm whether DLE can be utilized with diesel fuel or if an upgrade to water injection is required.

Additionally, Hydro would be required to buy an exhaust stack package as the units were configured with HRSG systems for a combined cycle facility, also known as a CCCT facility.

4.4.2.1.4 Shipment, Storage, and Preservation

The available units are located outside of the province. Although the units are currently available, Hydro is not in a position to purchase at this time, due to required advance approvals. Additionally, engineering design and site civil work could take upwards of two years before the unit is installed. With a potential two-year schedule lag, the unit would need to be shipped to the Island, stored, and properly preserved until installation.

4.4.2.2 Transformers

In addition to grey market CTs, Hydro also requires a GSU transformer for the CTs. The OEM reached out to transformer vendors separately for the availability of either a single 175 MVA or three 75 MVA units. The responses did not produce any grey market GSU transformers currently available; however, quotes were obtained for various new unit solutions. Depending on location, delivery lead times varied greatly with manufacturers ranging from 12 months to 48 months.

4.4.2.3 Costs and Schedule

The CT Options Report provides costing for both the grey market units and new units with a variance of approximately $33,000,000 (USD). As noted in Section 7.1 of Attachment 4 to this Appendix, there are various reasons why the OEM's offering will not meet Hydro's requirements and there are added costs to make the units compliant. Specifically, the units will need to be converted to operate on diesel fuel, upgraded to SC generators, purchase an exhaust package, potential BACT upgrades, shipping, storage, and preservation. The requirements to bring the grey market units to Hydro's required configuration will add additional costs thereby reducing the potential savings. Additionally, Hydro needs to complete FEED to validate the requirements from an operational and long-term service perspective. A substantial portion of FEED will need to be finished to conclusively determine what engine package will be required; therefore, purchasing a grey market unit at this time would be premature and could potentially lead to significant costs for retrofit.

Although the additional costs are not quantified within the CT Options Report, they reflect a portion of the initial capital cost for the unit package only and not the overall project cost; O&M costs are not included in the estimated costs and require further investigation in the FEED study.

4.4.2.4 Potential Cost and Emissions Reduction

Should a suitable 150 MW CT become available on the grey market and Hydro is in the position to purchase (from a reliability perspective), it would allow for the early retirement of one unit at the Holyrood TGS. Whether that would be Unit 1, Unit 2, or Unit 3,[66] would have to be taken into consideration at that time and would be dependant on the estimated capital work required for each Holyrood TGS unit. In consideration of costs, it is likely the unit with the highest capital cost requirement would be placed into retirement first.

By replacing the capacity of a base-loaded generating unit with a new 150 MW CT that is only required for peaking, it is expected that there will be fuel cost savings. However, by operating a Holyrood TGS unit as base-load generation through the winter (as is currently the case), it frees up energy for export if it is not required on the Island Interconnected System. Therefore, this analysis considered the net savings associated with the early installation of a 150 MW CT by considering the potential fuel savings, less the loss of export market revenue from the associated generation from a Holyrood TGS unit.

This analysis was conducted based on the characteristics of an LM6000 unit[67] and was assessed against the three Island Interconnected System load forecasts—Slow Decarbonization, Reference Case, and Accelerated Decarbonization.

[66] Unit 3 would be permanently converted to a SC.
[67] Should a suitable grey market CT become available, this analysis will need to be re-ran in consideration of that unit's characteristics.

The analysis did not consider O&M savings from retiring a Holyrood TGS unit or the O&M cost of a new 150 MW CT. Table 2 summarizes the potential net savings per year for each of the Island Interconnected System load forecast scenarios.

Table 2: Potential Net Savings per Year ($000)[68]

Year	Slow Decarbonization	Reference Case	Accelerated Decarbonization
2027	13,938	12,737	12,203
2028	15,027	14,411	13,807
2029	10,093	9,152	9,233
Total	**39,058**	**36,300**	**35,243**

Overall, the total benefit of installing a CT as early as 2027 is between $35 million and $39 million, or $9 million to $15 million per year, depending on system conditions. The total benefit reduces beyond 2027. The benefits of an early CT installation decreased by a modest amount as the load forecast increased from the Slow Decarbonization load forecast to the Accelerated Decarbonization load forecast, because an increase in demand would drive an increase in peak, leading to an increase in thermal generation. The benefit also decreased in 2029, due to the retirement of the existing wind farms in that year, which would lead to a similar increase in thermal generation.[69]

In addition, the potential reduction in emissions was assessed. Table 3 summarizes the potential reduction in emissions per year for each of the Island Interconnected System load forecast scenarios should one Holyrood TGS unit be replaced with a 150 MW CT from the grey market.[70]

Table 3: Potential Emission Reduction per Year (tonnes CO_2e)

Year	Slow Decarbonization	Reference Case	Accelerated Decarbonization
2027	153,099	154,870	154,544
2028	157,831	159,635	158,830
2029	151,510	152,094	155,153
Total	**462,440**	**466,599**	**468,527**

[68] Represented in CDN.
[69] As identified in Section 4.10, Hydro is committed to work closely with existing power purchase providers to determine options beyond the current retirement dates.
[70] Should a suitable grey market CT become available, this analysis will need to be re-ran in consideration of that unit's characteristics.

Overall, there is potential to reduce annual emissions from 151,510 tonnes CO_2e to 159,635 tonnes CO_2e on an annual basis. Should a CT be installed as early as 2027, there is a potential to reduce emissions by a total of 462,440 tonnes CO_2e to 468,527 tonnes CO_2e, depending on system conditions.

4.5 Wind Generation[71]

Newfoundland and Labrador is noted to have strong wind regimes, leading to the potential development of wind generation projects. Such projects could feasibly be executed by interconnecting a relatively large farm at transmission voltage level, such as a single 100 MW installation. The 100 MW project consists of 24, 4.26 MW turbines. It is estimated that this would provide an annual average energy of approximately 350 GWh per year with a firm capacity of 22 MW, the same ELCC as Hydro's existing wind farms.[72] To better determine the firm capacity contribution of future wind farms, an ELCC and wind saturation analysis for the Island Interconnected System is required.

As there are many sites that could be geographically suitable for wind project development in the province, no specific location has been identified. However, for transmission modelling purposes, it was assumed that 25% of the total wind requirement was constructed On-Avalon and 75% of the total wind requirement was constructed Off-Avalon. The more generation that can be constructed On-Avalon, the better from a transmission perspective; however, the more wind generation that is in the same area, the potential for a lower ELCC increases. This is because the wind generation would be correlated in the same area; thus, adding more wind generating capacity in that area would do little to increase reliability. If the wind developments were located in different areas with diverse wind regimes, it is more likely that not all of the projects would experience low wind at the same time.

A 100 MW wind farm would require interconnection via a 138 kV transmission line or higher.

[71] For additional information, please refer to "Wind Integration Study," Hatch Ltd., July 14, 2022," filed as Attachment 1 to Hydro's response to PUB-NLH-288, filed as part of the *RRA Study Review*.
[72] For additional information regarding wind ELCC, please refer to Appendix B.

4.6 Battery Storage Technology

4.6.1 Short-Duration Battery Storage Technology[73]

In 2023, Hydro engaged Wood to complete a study that includes updated information on the feasibility of BESS technology, including updated cost information for modelling purposes.

The BESS Study provided an update of the 2022 battery study,[74] which focused on the development of a battery storage project on the Avalon, including an update to the AACE Class 5 cost estimates, for the following two options:

- **Option 1**: 20 MW, 4-hour (80 MWh) battery;[75] and
- **Option 2**: 50 MW, 4-hour (200 MWh) battery.

These options were selected to be representative of a small and a large battery project and could be scaled to represent larger battery projects. The cost for larger storage capacities increases proportionately to the increase in MWh capacity, on average. The BESS Study also provided a cost estimate approximation for an 8-hour BESS system and a 12-hour BESS system.

BESS technology can be used to store surplus energy generated from wind, solar, and hydro, which can then be used to provide short-duration backup as well as firm up intermittent renewable sources, such as wind generation.

The delivery lead times for the BESS units have not increased compared to past estimates; however, the lead times for the major electrical equipment have increased considerably, resulting in a project duration of five years from the start of FEED[76] analysis to the completion of construction for both options. Currently, the lead times for power transformers and circuit breakers (43 months and 23 months, respectively) are exceptionally long. The indicative project schedule considers these long lead times.

---

[73] For additional information, refer to, "Battery Energy Storage System Report – Overview," Newfoundland and Labrador Hydro, September 29, 2023.
[74] The 2022 battery study—"BESS Project Preliminary Cost Estimate 254388-000-DF00-STY-002," Wood Canada Limited, rev. August 22, 2022 (originally issued July 12, 2022)—was filed as Attachment 3 to Hydro's response to PUB-NLH-288, filed as part of the *RRA Study Review*.
[75] The 20 MW battery storage option was ultimately removed from the Expansion Model to simplify the analysis.
[76] Front-end engineering design.

For the purposes of the BESS Study, Hydro chose to model battery ELCC based on a range of 40% to 80%. An ELCC of 60% was assumed as the base case for batteries, with sensitivities of 40% and 80% applied. See Sections 6.2.1and 6.2.2 for the Expansion Plan results. Hydro understands that determining battery ELCC is a matter that requires further study and has committed to doing so as stated in Section 10.0.

4.6.2 Long-Duration Battery Storage Technology

In 2023, engaged Wood to investigate batteries with larger storage capacities, likely from newer battery technologies (e.g., iron-air, flow, etc.) with potential storage capacities of up to 50 hours to 100 hours and with capacities of 20 MW to 50 MW.[77] The consultant was asked to provide guidance on storage capacities for any identified options, as well as a jurisdictional scan to see if there are other utilities using the identified technologies and assess the maturity of the technology.

The BESS Report includes an investigation of long-duration battery storage technologies that are available in the market with 50 to 100 hours of storage capability for 20 MW and 50 MW capacities. LDES can be used to store surplus energy generated from wind, solar, and hydro, which can then be used to provide multi-day power backup as well as firming-up intermittent renewable sources, such as wind generation.

Manufacturers are investigating various types of technologies for LDES and a review of the market was completed to identify manufacturers with new technologies, such as iron-air and flow batteries. As part of the BESS Study, 17 major energy storage manufacturers were contacted to assess technical and commercial details of their products, such as battery chemistry, power capacity, storage capacity, module sizes, land requirements, operating temperature range, existing installations, current phase of development, planned future projects, and product life. The key advantages of the technologies, the system components, cost, and current production facilities were also evaluated, where available. Limited information is available at this time, as most of the products are in the demonstration or early adoption stage and most manufacturers require non-disclosure agreements prior to sharing any significant technical or commercial information; therefore, Hydro would not be able to include the information within the Expansion Plan analysis.

[77] For additional information, refer to, “Battery Energy Storage System Report – Overview,” Newfoundland and Labrador Hydro, September 29, 2023.

Due to limited information shared by manufacturers, AACE Class 5 cost estimates for LDES project development could not be determined; rather, costs were determined based on publicly available information. At this time, Form Energy's iron-air battery is the only potentially cost-effective,[78] LDES solution that is expected to be available within the next ten years; however, its first pilot project is not planned to commence until this year (2024).

At this time, there are no proven installations for long-duration storage batteries and, while promising, uncertainties remain with this technology. Hydro will continue to seek updates on any emerging technology trends for long-term battery storage technologies.

4.7 Solar

A 20 MW ac photovoltaic solar system was considered, providing an annual energy contribution of 35 GWh. Solar energy projects, similar to wind energy projects, can help to diversify the generation mix.[79] Specific locations of the solar power systems were not determined; however, the site is expected to be near Gander, connecting to an existing terminal station on a 69 kV bus.

The solar power industry is maturing in Canada and is relatively new in Newfoundland and Labrador. This alternative does present risk in the province, due to adequacy of the solar resource (particularly given reduced daylight hours experienced during winter peak), access to injection points on the grid that can accommodate generation with modest system upgrades and that are also close to strong solar resource project locations, and design and resource constraints imposed by heavy snow load regimes.

4.8 Market Purchases

To date, Hydro has not secured any capacity support from external markets for a duration longer than one month and does not have a basis to assume that such solutions would be available to meet long-term planning requirements. On this basis, market purchases were not included as a resource option in the analysis. Hydro will continue to work with neighbouring utilities to explore the availability of firm supply solutions that could support Island Interconnected System reliability, which will continue to be included in the Near-Term Reliability Reports.

---

[78] Form Energy did not provide any cost estimate for their batteries; however, they indicated they are targeting less than \$20 (USD)/kWh (\$2,000 (USD)/kW for a 100-hour project) by 2030.
[79] For additional information, see "Solar Project Preliminary Cost Estimate, "Wood Canada Limited, August 22, 2022,"filed as Attachment 2 to Hydro's response to PUB-NLH-288, filed as part of the *RRA Study Review*.

4.9 Pumped Storage

In 2023, Hydro engaged Hatch to assess the feasibility of utilizing the infrastructure associated with the existing hydroelectric generating facilities to develop new pumped storage projects on the Island Interconnected System.[80]

Pumped storage facilities operate by pumping water from one reservoir to another at a higher elevation during periods of energy surplus (or periods when energy value is low) and returning the same water to the lower reservoir during periods of energy demand (when energy value is higher), generating electricity in the process. Hatch's assessment is divided into two tasks, as follows:

- **Task 1: Screening Study**: the screening study assessed nine hydroelectric generating stations on the Island that were identified by Hydro as potential candidates for pumped storage development. The nine locations were screened using a Pugh Analysis, which incorporates both the suitability of the topography and site location as well as consideration of social and environmental factors. Each factor was individually assessed based on the information available before weighting factors were applied; the results were then summated to create a ranking of the sites. The preferred sites were deemed those that had the highest ranking.
- **Task 2: Detailed Analysis and Costing**: The scope of this task was to undertake a high-level evaluation of the top two preferred sites, which were selected due to their higher head and possible potential for pumped storage suitability, and develop AACE Class 5 cost estimates for each.

Task 1 of the Pumped Storage Study screened the nine locations identified by Hydro for further assessment, using a Pugh analysis to rank the sites based on the aforementioned criteria.

The results of the ranking found that the majority of these locations were not economical, due to the outflow of these generating facilities directly to the ocean.[81] River reservoirs were ruled out due to the limitations that would be put on the capacity of the facility without the addition of a dam.

[80] For additional information, please refer to refer to, "Pumped Storage at Existing Hydro Sites – Overview," Newfoundland and Labrador Hydro, October 31, 2023.
[81] Pumped hydro facilities that use the ocean as a lower reservoir must be adapted for use in saltwater. This is often expensive, as it requires special equipment and may result in unacceptable environmental impacts associated with pumping seawater into the upper freshwater reservoir.

The screening process then ranked Hinds Lake, Star Lake, and Granite Lake sites the most promising, based on the adopted weighting used in the Pugh Analysis.[82,83] It was determined that Hinds Lake and Star Lake would be evaluated further, due to their higher head and possible potential for pumped storage suitability. The Granite Lake site was not pursued further due to its low head.

Task 2 of the Pumped Storage Study undertook a high-level evaluation of the two selected sites (Hinds Lake and Star Lake) and developed AACE Class 5 cost estimates for each. Given that the main objective of the Pumped Storage Study was to utilize the existing infrastructure and equipment, the evaluation of these sites was approached in two ways:

- **Layout 1**: The addition of new pump stations utilizes existing equipment only,[84] thus limiting the capacity of the pump station to 46 MW at Hinds Lake and 11 MW at Star Lake.
- **Layout 2**: Recognizing the capacities of Layout 1 do not utilize the full storage potential in the reservoirs, the limitation of utilizing existing equipment only was removed and a new standalone 200 MW pumped storage facility was proposed at each location. A facility of this size would have the capacity to store energy from new intermittent energy sources (e.g., wind farms) in the future.

The primary conclusions and recommendations of the Pumped Storage Study are as follows:

- The Layout 1 options provide no increase to Hydro's generating capacity and would not utilize the full storage potential of the two sites, thus providing minimal support for additional renewable generation as may be required in future. In Hatch's opinion, the options associated with Layout 1 should not be pursued further.
- The Layout 2 options increase Hydro's generating capacity, provide the ability to store excess energy (such as that from wind in times of high production and low demand), and generate energy when supply is low and demand is high. During generation, the existing facilities would also be used, thus providing 200 MW in addition to the current generating facility capacities.

---

[82] The generating assets at Star Lake are currently owned by GNL and are non-regulated assets. Star Lake has been included for fulsome analysis of options.
[83] The screening process undertaken in Task 1 is summarized in "Pumped Storage at Existing Hydro Sites – Overview," Newfoundland and Labrador Hydro, October 31, 2023, app. A.
[84] The assumption to utilize existing equipment only assumes the addition of new pump stations connected to the existing water conveyance.

- Hinds Lake appears more attractive than Star Lake on a cost-per-MW basis due to a higher head and a shorter penstock, which makes Hinds Lake more efficient in terms of producing the same energy when compared to Star Lake.
- The 200 MW installed capacity assumed for both Layout 2 options would need to be optimized to align with the grid demands if this resource option was pursued further.

At this time, further investigation into the feasibility of the Layout 2 option is required in consideration of environmental and transmission requirements. Hydro's next step is to assess pumped storage options at Greenfield sites on the Island Interconnected System. Pending the outcome of this study, Hydro will evaluate pumped storage options in the context of system requirements and generation expansion in future Resource Adequacy Plan filings.

4.10 Renewal of Existing PPAs

While the current methodology is to assume all PPAs retire in the Reliability Model and Expansion Model as per their respective end date, Hydro recognizes that there could be a benefit to renewing existing PPAs should they continue to contribute towards least-cost supply requirements. Hydro will continue to work closely with PPA counterparties to determine options going forward.[85]

5.0 Resource Options Not Under Consideration

This section highlights the resource options that Hydro has screened out as potential resource options at this time. Hydro remains committed to continuing to assess the technology and viability of these resources in the future, should circumstances change.

5.1 CCCTs

A CCCT facility consists of a CT fired on light oil, an HRSG, and a steam turbine generator; this resource option was traditionally considered in Hydro's resource mix. Most recently, Hydro assessed a 170 MW (net) facility capable of providing an estimated annual firm energy of 1,330 GWh.[86] However, with the advancement of the draft *CER*, it has become clear that base-loaded, fossil fuel-fired facilities that

[85] For PPA expiration dates, please refer to Section 5.1.6, Table 9 of Appendix B.
[86] "Reliability and Resource Adequacy Study – 2019 Update," Newfoundland and Labrador Hydro, November 15, 2019.

provide a significant source of energy no longer have a long-term place in Canada's electricity network and therefore no longer have a place within the Island or Labrador Interconnected Systems.

5.2 Modular Nuclear

Modular nuclear consists of steam turbine generation that utilizes nuclear fission as a heat source. Modular nuclear is a technology that meets the current and emerging electricity system technologies needed to meet net-zero GHG emissions, as identified in the draft *CER*. The power policy of Newfoundland and Labrador does not currently allow for the power supply from nuclear power;[87] however, Hydro will better understand the cost and viability of nuclear options through work currently being undertaken in other provinces.

6.0 Expansion Plan Development Process

The electricity landscape is in transition as efforts focus on reducing the reliance on carbon-emitting energy sources and increasing the use of electricity to power the economy and daily life. The evolving needs of the electrical system will become clearer over time as new policies and programs take effect, customer behaviours change, LIL reliability is better understood, and the potential of new technologies becomes apparent. However, immediate decisions are necessary to advance the planning, construction, and integration of new supply resources to ensure the retirement of aging thermal assets and to maintain reliability of the Island Interconnected System. With this in mind, the development process for the Expansion Plan was segmented into the following three steps:

- **Step 1: Development of Key Scenarios (Section 6.1):** There were 8 Expansion Plan scenarios developed, including variations of Island load forecast, LIL bipole EqFOR, and planning criteria;
- **Step 2: Development of Sensitivities (Section 6.2):** There were 11 sensitivities identified to further test Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required) Expansion Plan scenarios. The sensitivities considered parameters such as capital costs, fuel costs, limitations on certain resource options, variations in battery ELCC, etc.; and
- **Step 3: Further Analysis of Expansion Plans (Section 7.0):** Further analysis of the Expansion Plan was performed with respect to the draft CER, the LIL shortfall analysis, On-Avalon transmission constraints, and an iteration between the rate, load forecast, and expansion plan requirements.

[87] *Electrical Power Control Act, 1994*, SNL 1994, c E-5.1, s 3(f).

6.1 Development of Expansion Plan Scenarios

Hydro established eight main scenarios as the basis for the Expansion Plan analysis. The variables that were altered between scenarios include the capacity planning criteria, the LIL bipole EqFOR, the corresponding Planning Reserve Margins (calculated in Appendix B), and the Island Interconnected System load forecast. Table 4 provides a summary of the underlying major inputs for each scenario. The Labrador Interconnected System load forecast was held at the Reference Case for all scenarios; it is included in Table 4 for reference. This is because, overall, the need for additional on-Island resources is far more sensitive to the LIL bipole EqFOR and Island load forecast than Labrador load assumptions. New generation additions on the Island decreases reliance on the capacity of the LIL, which could potentially allow the existing generation in Labrador to serve the Labrador Interconnected System; however, for the purpose of this analysis, it was assumed that the energy generated at Muskrat Falls served the Island Interconnected System and was exported via the Maritime Link.

Table 4: Summary of Expansion Plan Scenarios

Scenario	Capacity Planning Criteria (LOLH)	LIL Bipole EqFOR (%)	Planning Reserve Margin[88,89] (%)	IIS Load Forecast	LIS Load Forecast
1	2.8	5	25.8	Reference	Reference
2	2.8	5	25.8	Accelerated Decarbonization	Reference
3	2.8	5	25.8	Slow Decarbonization	Reference
4	2.8	1	17.1	Slow Decarbonization	Reference
5	2.8	10	29.1	Accelerated Decarbonization	Reference
6	2.8	1	17.1	Accelerated Decarbonization	Reference
7	0.1 LOLE	5	35.1	Slow Decarbonization	Reference
8	2.8	100[90]	35.0	Reference	Reference

A description of each scenario, including rationale follows:

- **Scenario 1 (Reference Case):** Represents the expected case, or the scenario that incorporates assumptions that are considered most reasonable at this time by combining the Reference Case load forecast for the Island Interconnected System and the expected LIL bipole EqFOR of 5%. The expected case has historically formed the foundation of the recommended Expansion Plan.

[88] The Planning Reserve Margins presented here are inclusive of losses.
[89] Additional information on how the Planning Reserve Margins were calculated can be found in Section 5.1.7 of Appendix B.
[90] A LIL bipole EqFOR of 100% represents modelling the LIL as an Energy-Only Line.

- **Scenario 2:** Varies from Scenario 1 by incorporating Accelerated Decarbonization. This scenario is used to capture resource requirements if load growth on the Island accelerates more rapidly than anticipated in the Reference Case; however, LIL reliability remains as anticipated with a LIL bipole EqFOR of 5%.
- **Scenario 3:** Varies from Scenario 1 by incorporating Slow Decarbonization. This scenario is used to capture resource requirements if load growth on the Island increases more slowly than anticipated in the Reference Case; however, LIL reliability remains as anticipated with a LIL bipole EqFOR of 5%.
- **Scenario 4 (Minimum Investment Required):** Represents the scenario requiring the minimum investment (least amount of resource additions) based on a high level of LIL reliability (1% LIL bipole EqFOR) that can reasonably be expected in the long term and the lowest load growth (Slow Decarbonization) that can be reasonably anticipated on the Island Interconnected System. This scenario is intended to bookend the Expansion Plan scenarios by identifying the Minimum Investment Required on the Island Interconnected System.
- **Scenario 5 (Maximum Investment Required):** Represents the scenario requiring the maximum investment based on a low level of LIL reliability (10% LIL bipole EqFOR) and the highest load growth (Accelerated Decarbonization) reasonably anticipated on the Island Interconnected System. This scenario is intended to bookend the Expansion Plan scenarios by identifying the Maximum Investment Required on the Island Interconnected System.
- **Scenario 6:** Represents the resource requirements resulting from Island load growth consistent with Accelerated Decarbonization. The reliability of the LIL is assumed the best that can be reasonably achieved (1% LIL bipole EqFOR). This scenario helps to identify what resource options are required mainly due to policy-driven load growth (e.g., electrification) by assuming high Island growth and a reliable LIL.
- **Scenario 7:** Varies from Scenario 4 by increasing the stringency of the planning criteria from 2.8 LOLH to 0.1 LOLE. This scenario was used to understand the resources required to meet more stringent planning criteria.
- **Scenario 8:** Varies from Scenario 1 by assuming the LIL does not provide any capacity benefit to the Island Interconnected System (i.e., an Energy-Only line).

At this point in the development process, the Expansion Plan analysis bookends were established and included variations in LIL reliability, load forecasts for the Island Interconnected System, and capacity planning criteria.

6.2 Development of Expansion Plan Sensitivities

Hydro established 11 sensitivities to test select scenarios, which are summarized in Table 5.

Table 5: Expansion Plan Sensitivities

Sensitivity	Description
A	Fixed wind profile to meet firm energy criteria
AB40	Same as Sensitivity A with an assumed battery ELCC of 40%
AB80	Same as Sensitivity A with an assumed battery ELCC of 80%
AC	Same as Sensitivity A and removes forced CT fuel burn-off in consideration of the potential for contract negotiation and/or shelf life extension negating this requirement
AD	Same as Sensitivity A with the exception of increasing all Hydro capital costs by 50% in consideration of potential cost overruns
AE	Same as Sensitivity A and removes batteries as a resource option
AEC	A combination of Sensitivities A, AC, and AE to determine the impact of removing forced CT fuel burn-off in consideration of restricting batteries as a resource option
AEF	Same as Sensitivity AE with the additional restriction of limiting CT additions to 150 MW in consideration of current diesel fuel limitations on the Island
AEG	Same as Sensitivity AE with the exception of increasing CT fuel costs by 50% in consideration of potential future volatility in fuel costs
AEH	Same as Sensitivity AE with the exception of increasing CT capital costs by 50% in consideration of potential cost overruns
AEI	Same as Sensitivity AE with the addition of the potential Newfoundland Power 25 MW CTs in the years 2028, 2029, and 2030.[91]

The rationale behind each sensitivity selection is discussed within Sections 6.2.1 and 6.2.2.

To evaluate the Expansion Plan sensitivities, Hydro followed a systematic approach, beginning with running an unrestricted Expansion Model. Meaning that known constraints, such as fuel considerations and energy requirements to meet the firm energy criteria, were ignored and the model was enabled to determine the Least-Cost Expansion Plan. From here, known restrictions were added to the model and each Expansion Plan run to allow for systematic testing of the model against controlled variables to

[91] As a result of Newfoundland Power's intention to retire GTs in Wesleyville and Greenhill, Newfoundland Power has informed Hydro that it is exploring the addition of a total of 75 MW of CTs , with 25 MW becoming operational in 2028, another 25 MW in 2029, and the final 25 MW in 2030.

allow for better insight into the key drivers impacting resources selected by the PLEXOS model, should alternative futures materialize. This process enabled Hydro to narrow down the key drivers that could change the Expansion Plan over the timeframe in question, thus reducing uncertainty in the recommended Expansion Plan.

Out of the 8 Expansion Plan scenarios that were defined in Section 6.1, Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required) were selected to be tested against the 11 sensitivities. Hydro selected Scenario 1 (Reference Case) because this scenario usually forms the foundation of the recommended Expansion Plan and Hydro felt that it was prudent to understand what drivers could change this Expansion Plan scenario within the study period in question. Hydro selected Scenario 4 (Minimum Investment Required) for further sensitivity analysis to establish the minimum investment needs for the Island Interconnected System in consideration of a high level of LIL reliability that can reasonably be expected in the long term and the lowest load growth that can be reasonably anticipated. A further discussion, including the results, follows in Sections 6.2.1 to 6.2.2.

6.2.1 Scenario 1: Reference Case

Figure 3 outlines the Expansion Plan sensitivities identified in Table 5 that were completed for Scenario 1 (Reference Case), including each step in the process. Regardless of the sensitivity, or combination of sensitivities applied to Scenario 1, it is identified as the Reference Case Expansion Plan throughout to maintain consistency of nomenclature and to differentiate from the many scenarios considered in the analysis. Therefore, Scenario 1 (Reference Case) is related to the Expansion Plan scenario itself, not the sensitives applied.

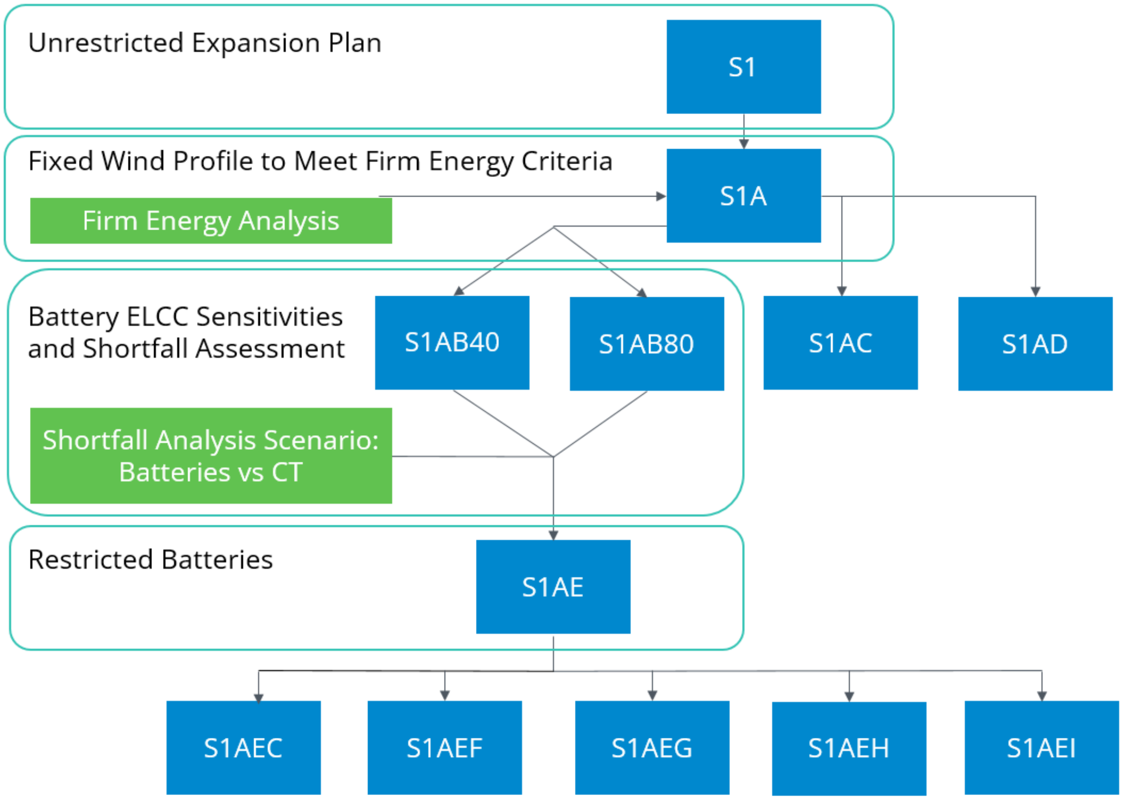


Figure 3: Scenario 1 Expansion Plan Sensitivity Analysis

The discussion of each Expansion Plan included in this section includes a summary of cost and emissions in consideration of Hydro's mandate to provide reliable electricity in an environmentally responsible manner at the lowest possible cost. A summary of the results are also provided in the following sections:

- Resource Requirements (Section 6.2.1.1);
- NPV Comparison (Section 6.2.1.2);
- Annual Emissions Comparison (Section 6.2.1.3); and
- Summary of Scenario 1 Expansion Plan Analysis (Section 6.2.1.4).

6.2.1.1 Resource Requirements

Scenario 1 includes the Reference Case load forecast and assumes a LIL bipole EqFOR of 5%, as summarized in Table 4 in Section 6.1. The results of the Expansion Plan sensitivities are summarized in Table 6 to Table 18 and include the resources built, its firm capacity and firm energy contributions, the cumulative number of units of the resource required in each year (green highlighting indicates the addition of one or more units in that year), and the total firm capacity and firm energy corresponding to the Expansion Plan, reported on an annual basis. Table 6 through Table 18 show the results for 2030 through 2034, the end of the planning horizon. No expansion units are required prior to 2030 in any of the scenarios based on the assumption of maintaining existing thermal assets through the Bridging Period. The firm capacity added to the system in each year may be more than the requirement due to the size of the units selected as least-cost resource options. For example, a 50 MW unit might be the least-cost option to fill a 20 MW requirement. Lastly, the NPV and annual GHG emissions are included for each Expansion Plan sensitivity, and are summarized for the sensitivities in Sections 6.2.1.2 and 6.2.1.3, respectively.

6.2.1.1.1 Scenario 1: Unrestricted

As mentioned previously, the first step in the analysis was to run an unrestricted Expansion Plan where known constraints were ignored and the Expansion Model was enabled to determine the Least-Cost Expansion Plan. The results of this Expansion Plan are summarized in Table 6.

Table 6: Scenario 1 (Unrestricted)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		2	2	2	2
Wind 100 MW	22	350			1	1	3
Firm Capacity (MW)			0	438	460	460	504
Firm Energy (GWh)			0	0	350	350	1050

In Scenario 1 (Unrestricted), the model builds Bay d'Espoir Unit 8 and two 142 MW CTs in 2031, following the retirement of existing thermal assets. In addition, 100 MW of wind is required in 2032, increasing to a total of 300 MW of wind by the end of the study period. What this Expansion Plan indicates is that Bay d'Espoir Unit 8 and two CTs are cost-competitive capacity resource options, while wind is the most economic energy resource. However, while the Island Interconnected System capacity needs are met, the Expansion Model considers average hydrology, not firm hydrology; therefore, it does not meet the firm energy requirements outlined in Section 3.0 and discussed in detail in Section 5.3 of

Appendix B. The total cost (in terms of NPV)[92] of this Expansion Plan is $3.9 billion and the annual emissions are estimated to be 48 kt from 2031 onwards.

6.2.1.1.2 Scenario 1A: Fixed Wind Profile

To ensure Hydro's firm energy criteria was met, the second step of the analysis was to force the Expansion Model to include a fixed wind profile that ensures the firm energy criteria is met. As the wind has an assumed firm capacity contribution of 22%, it was expected this restriction would affect the capacity resources that were selected by the Expansion Model in Scenario 1 (Unrestricted). The results of this Expansion Plan are summarized in Table 7.

Table 7: Scenario 1A (Fixed Wind Profile)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	2	2
Wind 100 MW	22	350	2	4	5	5	5
Battery 50 MW	30[93]	0		1	1	1	1
Firm Capacity (MW)			44	414	436	578	578
Firm Energy (GWh)			700	1400	1750	1750	1750

In Scenario 1A (Fixed Wind Profile), the model builds Bay d'Espoir Unit 8, one 142 MW CT, and one 50 MW battery by 2031. The requirement for additional capacity is identified by 2033 and the need is met by another 142 MW CT. As the Holyrood TGS is assumed to retire at the end of the first quarter of 2030, this results in a significant loss of firm energy to the Island Interconnected System; therefore, 200 MW of wind is required in the same year, escalating to 500 MW of wind by 2032. As expected, the increase in wind generation to meet the firm energy criteria has affected the capacity resources selected. In this case, the second CT is pushed to later in the study period and a 50 MW battery meets the capacity need in the early part of the study period. Fixing the wind profile to meet Hydro's firm energy requirements results in an NPV increase of approximately $0.9 billion, for a total NPV of $4.8 billion. The annual emissions are estimated to be 25 kt until the CT is added, at which point the

[92] The total Expansion Plan costs include generation capital costs, fixed and variable O&M costs, and fuel costs. Export market revenue has not been included and does not vary significantly for a given load forecast. Financing costs associated with new capital spending are excluded. The cost of transmission requirements are also not considered in the NPV analysis.
[93] An ELCC of 60% applied to a 50 MW battery results in 30 MW of firm capacity.

annual emissions increase to 48 kt, consistent with the emissions from 2031 onwards in Scenario 1 (Unrestricted).

Wind was selected as the least-cost energy resource (as opposed to solar or small hydro options) to meet the firm energy requirements of the Island Interconnected System. The fixed wind profile was maintained throughout the remainder of the analysis to ensure that firm energy criteria is being met in each Expansion Plan sensitivity for Scenario 1 (Reference Case). The firm energy requirement is dependent only on the Island Interconnected System load forecast and the fixed wind profile is consistent for each load forecast scenario.

At this step in the process, the firm energy requirements have been resolved; it has been determined that Bay d'Espoir Unit 8 and the CT are least-cost, competitive resources. What has also appeared as a potential least-cost option is a 50 MW battery, as the other variables have been tested. Because Bay d'Espoir Unit 8, CTs, and a 50 MW battery are proving to be cost-competitive capacity resources, Hydro decided to test the sensitivities of these resource options further by running the following sensitivities:

- **Sensitivity 1AB40**: Same as Sensitivity A (Fixed Wind Profile) with an assumed battery ELCC of 40% to capture the low-end of the assumed ELCC range;
- **Sensitivity 1AB80**: Same as Sensitivity A (Fixed Wind Profile) with an assumed battery ELCC of 80%[94] to capture the high-end of the assumed ELCC range;
- **Shortfall Analysis Scenario**: Batteries versus CT;
- **Sensitivity 1AC**: Same as Sensitivity A (Fixed Wind Profile) except for removing forced CT fuel burn-off in consideration of the potential for contract negotiation and/or shelf life extension negating this requirement; and
- **Sensitivity 1AD**: Same as Sensitivity A (Fixed Wind Profile) except for increasing all Hydro capital costs by 50% in consideration of potential cost overruns.

6.2.1.1.3 Scenario 1AB40: Fixed Wind Profile and Battery ELCC of 40%

The results of the Sensitivity 1AB40 Expansion Plan are summarized in Table 8.

[94] The capacity of the battery was reduced by 20% to reflect the imperfect ability of batteries to contribute during the peak.

Table 8: Scenario 1AB40 (Fixed Wind Profile and Battery ELCC of 40%)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	1	2
CAT Unit 3	68.2	0		1	1	1	1
Wind 100 MW	22	350	2	4	5	5	5
Firm Capacity (MW)			44	452	474	474	616
Firm Energy (GWh)			700	1400	1750	1750	1750

For Scenario 1AB40, Bay d'Espoir Unit 8, a 142 MW CT, and Cat Arm Unit 3 were selected to meet the capacity requirements by 2031, with a second 142 MW CT required by 2034. The wind requirements remain the same as the wind profile remains fixed to meet the firm energy criteria. Batteries with ELCC's of 40% were not selected as a least-cost option by the model; rather, Cat Arm Unit 3 appeared as a potential least-cost resource option for the first time. The NPV of this Expansion Plan is $4.8 billion, the same as Scenario 1A (Fixed Wind). The annual emissions in 2031 are estimated to be 25 kt until 2034 when the second CT is added, resulting in annual emissions of 48 kt.

6.2.1.1.4 Scenario 1AB80: Fixed Wind Profile and Battery ELCC of 80%

To capture the high-end of the battery ELCC range, Sensitivity 1AB80 was run; the results of the Expansion Plan are summarized in Table 9.

Table 9: Scenario 1AB80 (Fixed Wind Profile and Battery ELCC of 80%)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
Wind 100 MW	22	350	2	4	5	5	5
Battery 50 MW	40[95]	0		4	4	5	6
Firm Capacity (MW)			402	424	464	504	544
Firm Energy (GWh)			700	1400	1750	1750	1750

[95] An ELCC of 80% applied to 50 MW battery results in 40 MW of firm capacity.

For Scenario 1AB80, Bay d'Espoir Unit 8 and four 50 MW batteries are selected to meet the capacity requirements by 2031, with batteries increasing to six 50 MW units, totalling 300 MW of batteries by the end of the study period. The wind requirements remain the same, as the wind profile remains fixed to meet the firm energy criteria. The NPV of this Expansion Plan is $4.7 billion, a decrease from Scenario 1A (Fixed Wind) by $0.1 billion. Varying battery ELCC between 40% and 80% has a negligible impact on the NPV analysis compared to Scenario 1A (Fixed Wind), which assumes a battery ELCC of 60%. As a CT is not selected in this Expansion Plan, the annual emissions are minimal, ranging from 1 kt to 2 kt from 2031 onward.

6.2.1.1.5 Shortfall Analysis Scenario: Batteries vs CT

At this time Hydro is choosing to model battery ELCC based on a range of 40% to 80% in the near term; however, Hydro understands that determining battery ELCC is a matter that requires further study. In general, batteries provide a lower incremental reliability benefit to the Island Interconnected System, which faces most of its supply shortage risk during the winter period. Therefore, a shortfall analysis scenario was included to further analyze the reliability contribution of batteries as compared to CTs during a prolonged loss of the LIL in the winter. Four runs were completed where one 47.2 MW CT at a time was replaced with an equivalent 47.2 MW battery:[96]

- Scenario A: Three 47.2 MW CTs with no batteries;
- Scenario B: Two 47.2 MW CTs with one 47.2 MW battery;
- Scenario C: One 47.2 MW CTs with two 47.2 MW batteries; and
- Scenario D: Three 47.2 MW batteries.

The analysis was also completed with four- and eight-hour batteries to measure the impact of battery duration on the results. The resulting unserved energy over the six-week period is outlined in Table 10.

[96] The LM6000 CT consists of three 47.2 MW units for a total rated capacity of 141.6 MW. To equate batteries to CTs in this analysis, the battery capacity was assumed 47.2 MW as well.

Table 10: Unserved Energy Comparison over Six-Week LIL Shortfall

Scenario	Description	Unserved Energy w/ 4- Hour Battery (GWh)	Increase in Unserved Energy[97] (%)	Unserved Energy w/ 8-Hour Battery (GWh)	Increase in Unserved Energy[98] (%)
A	3, 47.2 MW CTs + No Batteries	1,752	-	1,752	-
B	2, 47.2 MW CTs + 1, 47.2 MW Battery	1,780	1.6	1,757	0.3%
C	1, 47.2 MW CT + 2, 47.2 MW Batteries	1,921	9.6	1,881	7.3%
D	No CTs + 3, 47.2 MW Batteries	3,036	73.3	2,894	65.2%

Based on these results, during a prolonged outage in the winter, there may be minimal differences in the reliability contribution of a single 47.2 MW CT and a single 47.2 MW battery (four-hour or eight-hour duration). In the cases with two or three 47.2 MW batteries, the amount of unserved energy increases substantially. In addition, there was a minimal increase in reliability from four-hour duration to eight-hour duration batteries. Further analysis would be required to determine if the incremental reliability benefit would warrant doubling the capital cost to increase storage duration from four hours up to eight hours.

Two important factors may be inflating the reliability contribution of batteries:

1) The Reliability Model has perfect foresight within the day, so it “knows” the optimal time to charge and discharge the battery, which could materially differ from a real-life situation; and

2) The Reliability Model does not account for the duration of outages, which will have a significant effect on the amount of energy available in a day.

Additional analysis is required to quantify the reliability contribution of batteries. The preliminary analysis presented above suggests that similar reliability benefits may be experienced for up to 47.2 MW of batteries as compared to a 47.2 MW CT; beyond this amount, batteries have far less utility in backing up the LIL during an extended outage. However, there is a noted synergy between added volumes of intermittent generation (e.g., wind and/or solar) and batteries. Hydro recognizes that battery

[97] Percent increase in unserved energy of four-hour batteries compared to Scenario A.
[98] Percent increase in unserved energy of eight-hour batteries compared to Scenario A.

technology is constantly improving and the costs are reducing, which makes it an attractive option to meet future load growth requirements. To be prepared for the potential future load growth, Hydro is committed to further study of battery ELCC, as well as the expected synergies between wind and batteries in the context of the Island Interconnected System. These improvements will be completed to inform the next Resource Adequacy Plan update.

6.2.1.1.6 Scenario 1AC: Fixed Wind Profile and No Fuel Burn-Off

At this time, Hydro is assuming that ten days of fuel storage associated with the CT as a resource option has to be burned off annually. While further study is required to assess extending the shelf life of the fuel in storage, and/or determining if there is a way to cycle unused fuel via contractual means, the Expansion Model is being forced to burn off the fuel annually as a worst-case scenario to ensure Hydro is fully capturing the associated costs. A sensitivity was designed to remove this fuel burn-off requirement; instead, fuel costs are reflective of forecast production requirements. The results of this Expansion Plan are summarized in Table 7.

Table 11: Scenario 1AC (Fixed Wind Profile and No Fuel Burn-Off)[99]

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
CT	141.6	0		3	3	3	3
Wind 100 MW	22	350	2	4	5	5	5
Firm Capacity (MW)			44	513	535	535	535
Firm Energy (GWh)			700	1400	1750	1750	1750

In Scenario 1AC, the Expansion Model is choosing to build three 142 MW CTs by 2031,[100] following the retirement of existing thermal assets. With no fuel burn-off requirement, the CT becomes the least-cost capacity option, ahead of Bay d'Espoir Unit 8 and batteries (with an assumed ELCC of 60%). The wind requirements remain the same, as the wind profile remains fixed to meet the firm energy criteria. By reducing the fuel burn-off, the NPV reduces to $4.3 billion, a $0.5 billion reduction compared to the NPV of Scenario 1A (Fixed Wind). The annual emissions are minimal from 2031 onward, ranging between 2 kt

[99] Unless specified, all scenarios assumed forced fuel burn off, if CTs are selected as least-cost expansion options.
[100] As identified in Section 4.4, Hatch recommends a CT capacity of no more than 150 MW based on the current availability of fuel supply on the Island.

and 5 kt. This represents a decrease in annual emissions of approximately 90% compared to the estimated emissions for Scenario 1A (Fixed Wind).

6.2.1.1.7 Scenario 1AD: Fixed Wind Profile and Hydro Capital Costs + 50%

Another sensitivity was included to reflect the potential for cost overruns of hydro projects. In this sensitivity, the capital cost of all hydroelectric options, including Bay d'Espoir Unit 8, was increased by 50%. The results of this Expansion Plan are summarized in Table 12.

Table 12: Scenario 1AD (Fixed Wind Profile and Hydro Capital Costs + 50%)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
CT	141.6	0		2	2	3	3
Wind 100 MW	22	350	2	4	5	5	5
Battery 50 MW	30[101]	0		1	1	1	1
Firm Capacity (MW)			44	401	423	565	565
Firm Energy (GWh)			700	1400	1750	1750	1750

For Scenario 1AD, the Expansion Model is choosing to build two 142 MW CTs (which includes annual forced fuel burn-off as a conservative measure) and one 50 MW battery with an assumed ELCC of 60% by 2031, escalating to three 142 MW CTs by 2033. The wind requirements remain the same, as the wind profile remains fixed to meet the firm energy criteria. As expected, Bay d'Espoir Unit 8, or any other hydro project, is no longer being selected as a least-cost capacity resource due to the 50% increase in capital cost that was applied. The scenario estimates an NPV of $5.0 billion, $0.2 billion more than Scenario 1A. The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 48 kt until the third CT is constructed, which increases the annual emissions to 71 kt. This is approximately 23 kt higher per year than Scenario 1A (Fixed Wind), which has one less CT.

For all scenarios described from here on, batteries have been restricted as a resource option, based on the energy availability concern in the winter in the event of a LIL outage. Unless specified, all scenarios assumed forced fuel burn-off if CTs are selected as least-cost expansion options.

[101] An ELCC of 60% applied to a 50 MW battery results in 30 MW of firm capacity.

6.2.1.1.8 Scenario 1AE: Fixed Wind Profile and No Batteries

Scenario 1AE includes the fixed wind profile and does not allow batteries. The results of this Expansion Plan are summarized in Table 13.

Table 13: Scenario 1AE (Fixed Wind Profile and No Batteries)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		2	2	2	2
Wind 100 MW	22	350	2	4	5	5	5
Firm Capacity (MW)			44	526	548	548	548
Firm Energy (GWh)			700	1400	1750	1750	1750

For Scenario 1AE, Bay d'Espoir Unit 8 and two 142 MW CTs were selected by 2031. The wind requirements remain the same as, the wind profile remains fixed to meet the firm energy criteria. For this scenario, the NPV is $4.8 billion. By restricting batteries from the analysis, the NPV is the same as Scenario 1A (Fixed Wind). Similar to previous scenarios that include two CTs, the annual emissions are estimated to be 48 kt from 2031 onward.

To test the Scenario 1AE (Fixed Wind Profile and No Batteries) Expansion Plan further, additional sensitivities were applied, including:

- **Sensitivity 1AEC**: Same as Sensitivity AE with no forced CT fuel burn-off;
- **Sensitivity 1AEF**: Same as Sensitivity AE with the additional restriction of limiting CT additions to 150 MW in consideration of current diesel fuel limitations on the Island;
- **Sensitivity 1AEG**: Same as Sensitivities AE with the exception of increasing CT fuel costs by 50% in consideration of potential future volatility in fuel costs;
- **Sensitivity 1AEH**: Same as Sensitivities AE with the exception of increasing CT capital costs by 50% in consideration of potential cost overruns; and
- **Sensitivity 1AEI**: Same as Sensitivities AE with the addition of the potential Newfoundland Power 25 MW CTs in the years 2028, 2029, and 2030, totalling 75 MW.

6.2.1.1.9 Scenario 1AEC: Fixed Wind Profile, No Batteries, and No Fuel Burn-Off

The results of Scenario 1AEC Expansion Plan that removes the restriction of forcing CT fuel burn-off is summarized in Table 14.

Table 14: Scenario 1AEC (Fixed Wind Profile, no Batteries, No Fuel Burn-Off)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
CT	141.6	0		3	3	3	3
Wind 100 MW	22	350	2	4	5	5	5
Firm Capacity (MW)			44	513	535	535	535
Firm Energy (GWh)			700	1400	1750	1750	1750

In this scenario, three 142 MW CTs are selected as least-cost resource options by 2031, the same as Scenario 1AC. The wind requirements remain the same, as the wind profile remains fixed to meet the firm energy criteria. Compared to Scenario 1AE (Fixed Wind, No Batteries), by removing the fuel burn-off requirement, the least-cost capacity requirements becomes three 142 MW CTs by 2031, instead of Bay d'Espoir Unit 8 and two 142 MW CTs by 2031 when the annual fuel burn-off is required. The NPV of this scenario is \$4.3 billion, approximately \$0.5 billion less than Scenario 1AE (Fixed Wind, No Batteries). Similar to Scenario 1AC, by removing the forced fuel burn-off, the annual emissions range between 2 kt to 5 kt from 2031 onward.

6.2.1.1.10 Scenario 1AEF: Fixed Wind Profile, No Batteries, and Limit CT

Should fuel (renewable or otherwise) become more readily available, it is important for Hydro that the implications for resource selection in the Expansion Model are well understood. Therefore, no previous Expansion Plans restricted the number of CTs that could be constructed. At this time, however, it has been determined that fuel availability is limited to support only 150 MW of CTs.[102] An Expansion Plan was completed that was restricted to no more than one approximately 150 MW CT as a resource option. The results of this Expansion Plan are summarized in Table 15.

[102] As identified in Section 4.4, Hatch recommends a CT capacity of no more than 150 MW based on the current availability of fuel supply on the Island.

Table 15: Scenario 1AEF (Fixed Wind Profile, No Batteries, and Limit CT)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	1	1
CAT Unit 3	68.2	0		1	1	1	1
Proxy Capacity	50	0					1
Wind 100 MW	22	350	2	4	5	5	5
Firm Capacity (MW)			44	452	474	474	524
Firm Energy (GWh)			700	1400	1750	1750	1750

For Scenario 1AEF, Bay d'Espoir Unit 8, one 142 MW CT, and Cat Arm Unit 3 are required by 2031. An additional proxy capacity resource option representing 50 MW of CT generation was also required by the end of the study period. The proxy capacity is a placeholder capacity option and the Expansion Model is selecting this resource option in advance of selecting other hydro capacity options (such as Island Pond, Round Pond, or Portland Creek) due to the significant costs associated with these greenfield resource options. It should not be inferred that an additional 50 MW CT would be the suitable resource option in this scenario. It is expected that the model selects a proxy capacity resource as, at this time, the model is encountering limited resource options to meet reliability criteria and the remaining resource options are significantly more costly. The wind requirements remain the same, as the wind profile remains fixed to meet the firm energy criteria and batteries are excluded as a resource option. The NPV result of this scenario is $5.8 billion. By restricting the number of CTs that can be installed on the system, the NPV increases by $1.1 billion, compared to Scenario 1AE (Fixed Wind, No Batteries). The annual emissions from 2031 onward are estimated to be 25 kt in this scenario, rising to 35 kt in 2034 with the addition of a proxy capacity unit.

For information on Scenario 1AEF transmission requirements, please refer to Section 7.3.

6.2.1.1.11 Scenario 1AEG: Fixed Wind Profile, no Batteries, and Increase Fuel Costs

Further testing of CTs as a resource option includes increasing the fuel costs by 50% in recognition of increasing future demand for diesel fuel in combination with the potential for future supply shortages in Canada as discussed in Section 4.4.1. The results of this Expansion Plan are summarized in Table 16.

Table 16: Scenario 1AEG (Fixed Wind Profile, No Batteries, and Increase Fuel Costs)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		2	2	2	2
Wind 100 MW	22	350	2	4	5	5	5
Firm Capacity (MW)			44	526	548	548	548
Firm Energy (GWh)			700	1400	1750	1750	1750

For Scenario 1AEG, Bay d'Espoir Unit 8 and two 142 MW CTs were required by the end of the study period. The wind requirements remain the same, as the wind profile remains fixed to meet the firm energy criteria and batteries are excluded as a resource option. Even with a 50% increase to expected future fuel costs, a CT remains cost-competitive with Bay d'Espoir Unit 8 and remains the least-cost option in comparison to other resource options. The NPV of Scenario 1AEG is $5.0 billion, a $0.2 billion increase compared to Scenario 1AE (Fixed Wind, No Batteries). The annual emissions are estimated to be 48 kt from 2031 onward.

6.2.1.1.12 Scenario 1AEH: Fixed Wind Profile, no Batteries, and Increase CT Capital Costs

Another sensitivity was completed to explore increasing the CT capital cost by 50%. This could reflect cost overruns, or the AACE Class 3 cost estimate completed as part of FEED being higher than anticipated. The results of this Expansion Plan are summarized in Table 17.

Table 17: Scenario 1AEH (Fixed Wind Profile, no Batteries, and Increase CT Capital Costs)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		2	2	2	2
Wind 100 MW	22	350	2	4	5	5	5
Firm Capacity (MW)			44	526	548	548	548
Firm Energy (GWh)			700	1400	1750	1750	1750

The Expansion Plan for Scenario 1AEH is the same as Scenario 1AEG, indicating that either a 50% increase in fuel cost or a 50% increase in CT capital cost does not change the Expansion Plan outcome.

The NPV of Scenario 1AEH is $5.5 billion, a $0.7 billion increase over Scenario 1AE (Fixed Wind, No Batteries). The annual emissions are estimated to be 48 kt from 2031 onward.

6.2.1.1.13 Scenario 1AEI: Fixed Wind Profile, No Batteries, and Include NP CT Additions

Lastly, other CTs support regional reliability, such as Newfoundland Power's CTs in Wesleyville and Greenhill. While Newfoundland Power is looking to retire these units, it has expressed that there may be justification to replace these units and the thermal units in the Port aux Basques region on the basis of long-term regional transmission reliability requirements and with the potential to support overall system reliability. While such assessments are beyond the scope of the *RRA Study Review*, Hydro is continuing to work with Newfoundland Power to explore these solutions and to understand their benefits in terms of provincial supply. Newfoundland Power is exploring the addition of 75 MW of CTs, with 25 MW operational in 2028, another 25 MW in 2029, and the final 25 MW in 2030.

While this assessment is preliminary, and is expected to go through the Board's regulatory review process, Hydro felt it prudent to complete a sensitivity to determine the impacts on the Expansion Plan. The results of this Expansion Plan are summarized in Table 18.

Table 18: Scenario 1AEI (Fixed Wind Profile, No Batteries, and Include NP CT Additions)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	1	1
CAT Unit 3	68.2	0					1
Wind 100 MW	22	350	2	4	5	5	5
Firm Capacity (MW)			44	384	406	406	474
Firm Energy (GWh)			700	1400	1750	1750	1750

In the case of Scenario 1AEI, where Newfoundland Power has 75 MW of additional generation located off of the Avalon, the need for a second 150 MW CT in 2031 identified in Scenario 1AE (Fixed Wind, No Batteries) is eliminated, instead the model selects Cat Arm Unit 3 in 2034. However, both Bay d'Espoir Unit 8 and one 142 MW CT located on the Avalon, are still required by 2031. The wind requirements remain the same, as the wind profile remains fixed to meet the firm energy criteria. The NPV of this scenario is $4.4 billion, reflecting a $0.4 billion reduction from Scenario 1AE (Fixed Wind, No Batteries).

However, the costs associated with Newfoundland Power's additional 75 MW are not included in the NPV analysis. The annual emissions are estimated to be 25 kt from 2031 onward, which excludes the emissions from the CTs proposed by Newfoundland Power.

How the fueling of the potential 75 MW CTs would be supplied in addition to Hydro's existing CT and potential new CT requires further study. For information on Scenario 1AEI transmission requirements, please refer to Section 7.3.

6.2.1.2 NPV Comparison

The total Expansion Plan costs presented herein include generation capital costs, fixed and variable O&M costs, and fuel costs. Export market revenue has not been included and does not vary significantly for a given load forecast.[103] Financing costs associated with new capital spending are excluded. The costs of transmission requirements are also not considered in the NPV comparison; however, these costs are addressed in Section 7.3 and included in the rate impact analysis in Section 7.4.1. The annual costs from the PLEXOS model are translated to an NPV using the WACC to discount future financial impacts to today's value. Because expansion units will continue to operate well beyond the 2034 planning horizon (the economic life of the resources considered in this study range from 20 to 60 years), the objective function used in the PLEXOS model sums the present values of costs beyond the final horizon year. It is assumed that annualized build costs and operational costs are extended into perpetuity beyond the final year of the modelling horizon, and these are discounted and then summed to arrive at the total NPV cost presented herein.

Chart 10 compares the NPV of the Scenario 1 (Reference Case) sensitivities to help identify the cost impact of each sensitivity that was applied. This section is intended to demonstrate the cost impact of each sensitivity to help determine the Least-Cost Expansion Plan that meets Hydro's probabilistic planning criteria and firm energy criteria.

[103] It is likely that there will be market revenue associated with resource options that generate energy that could marginally decrease the NPV of each scenario; however, to avoid counting on a potential market revenue forecast that may not occur, it was removed from this analysis.

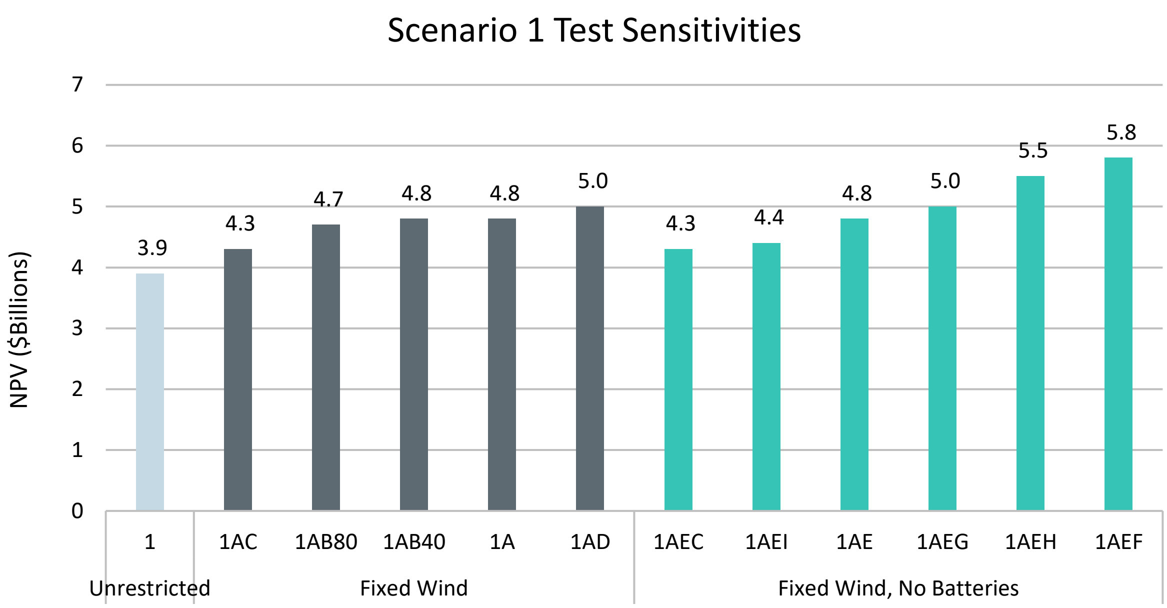


Chart 10: NPV Scenario 1 (Reference Case) Test Sensitivity Comparison[104]

It is important to note that the NPV for Scenario 1AC and Scenario 1AEC are low because the forced fuel burn-off has been removed. The savings in these scenarios compared to other scenarios in this analysis are not due to a reduction in expansion costs but through improved fuel management practices. The NPV for Scenario 1AEI is also low, not due to a reduction in expansion costs but because it does not account for Newfoundland Power's costs incurred by the potential construction of a total of 75 MW of CTs.

6.2.1.3 Annual Emissions Comparison

Chart 11 compares the annual emissions of CO_2e (kt per year) for each of the Scenario 1 (Reference Case) sensitivities to help identify the emissions impact of each sensitivity applied.

[104] All costs are presented in 2024 CDN.

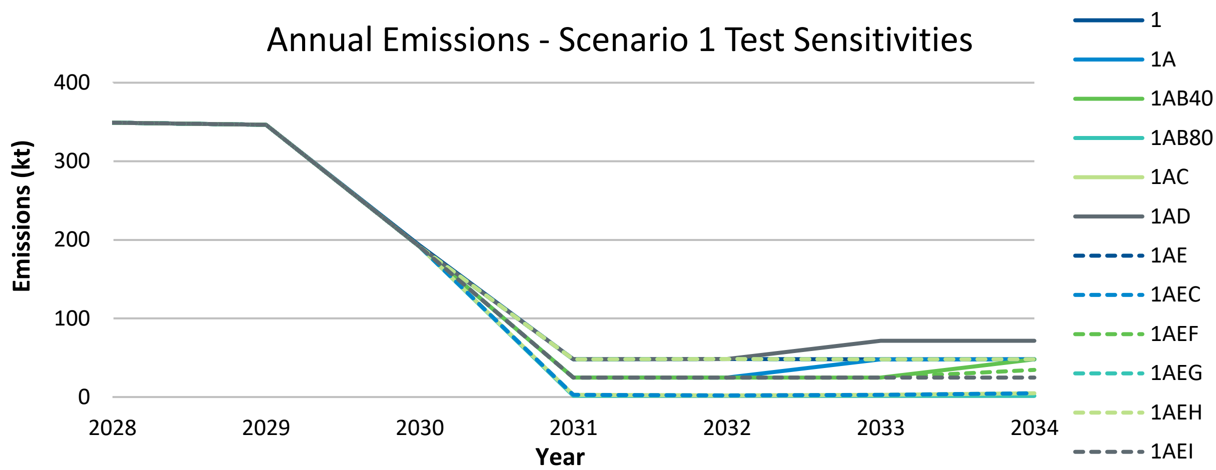


Chart 11: Comparison of Scenario 1 Sensitivities Annual Emissions[105]

As Chart 11 demonstrates, it is evident that the estimated annual emissions decrease dramatically in all cases upon retirement of the existing thermal assets (Holyrood TGS, Hardwoods GT, and Stephenville GT). Emissions up to 2029 are estimated to be approximately 350 kt per year, dropping to no more than 70 kt (which corresponds to Scenario 1AD that builds the most CTs and assumes an annual fuel burn-off requirement). This is an approximately 80% reduction in fuel emissions that may be achieved within the study period, once the Holyrood TGS is retired. Should system conditions differ from that assumed in this analysis, annual emissions could be more than presented.

6.2.1.4 Summary of Scenario 1 (Reference Case) Expansion Plans

In total, 11 sensitivities were applied to Scenario 1 (Reference Case), summarized in Table 19 for ease of reference. The capacity and energy builds identified in Table 6 through Table 18 are included in Table 19 based on the year required.

[105] The full time horizon of the study period was limited to 2028 to 2034 to give better visibility to the differing emissions between scenarios once the Holyrood TGS is retired in 2030. Annual emissions from 2024 through 2028 were approximately 350 kt for all sensitivities analyzed.

Table 19: Summary of Scenario 1 Expansion Plans

Scenario	Description	Capacity Build				Energy Build					NPV[106] ($Billions)	Max. Emissions[107] (kt)
		2031	2032	2033	2034	2030	2031	2032	2033	2034		
1	Unrestricted	BDE Unit 8, 2 CTs						1 Wind		2 Wind	3.9	48
1A	Fixed Wind Profile	BDE Unit 8, 1 CT, 1 Battery		1 CT		2 Wind	2 Wind	1 Wind			4.8	48
1AB40	Fixed Wind, Batteries ELCC 40%	BDE Unit 8, 1 CT, CAT Unit 3			1 CT	2 Wind	2 Wind	1 Wind			4.8	48
1AB80	Fixed Wind, Batteries ELCC 80%	BDE Unit 8, 4 Batteries		1 Battery	1 Battery	2 Wind	2 Wind	1 Wind			4.7	2
1AC	Fixed Wind, No Fuel Burn-Off for CT	3 CTs				2 Wind	2 Wind	1 Wind			4.3	5
1AD	Fixed Wind, Hydro Capital Cost +50%	2 CTs, 1 Battery		1 CT		2 Wind	2 Wind	1 Wind			5.0	71
1AE	Fixed Wind, No Batteries	BDE Unit 8, 2 CTs				2 Wind	2 Wind	1 Wind			4.8	48
1AEC	Fixed Wind, No Batteries, No Fuel Burn-Off for CT	3 CTs				2 Wind	2 Wind	1 Wind			4.3	5
1AEF	Fixed Wind, No Batteries, Limit CT to 150 MW	BDE Unit 8, 1 CTs, CAT Unit 3			1 Proxy	2 Wind	2 Wind	1 Wind			5.8	35
1AEG	Fixed Wind, No Batteries, Fuel Cost +50%	BDE Unit 8, 2 CTs				2 Wind	2 Wind	1 Wind			5.0	48
1AEH	Fixed Wind, No Batteries, CT Capital Cost +50%	BDE Unit 8, 2 CTs				2 Wind	2 Wind	1 Wind			5.5	48
1AEI	Fixed Wind, No Batteries, NP CTs (75 MW)	BDE Unit 8, 1 CT			CAT Unit 3	2 Wind	2 Wind	1 Wind			4.4[108]	25[109]

[106] Exclusive of transmission upgrade costs and market export opportunities.
[107] Maximum emissions (kt) from 2031 onwards.
[108] Excludes the cost of Newfoundland Power’s 75 MW CTs.
[109] Excludes the emissions of Newfoundland Power’s 75 MW CTs.

6.2.2 Scenario 4: Minimum Investment Required

Similar to the process followed in Section 6.2.1, Figure 4 outlines the Expansion Plan sensitivities identified in Table 5 that were completed for Scenario 4, the Minimum Investment Required scenario. Regardless of the sensitivity (or combination of sensitivities) applied to Scenario 4, it is identified as the Minimum Investment Required Expansion Plan throughout to maintain consistency of nomenclature and to differentiate from the many scenarios considered in the analysis. Therefore, Scenario 4 (Minimum Investment Required) is in relation to the Expansion Plan scenario itself, not the sensitives applied.

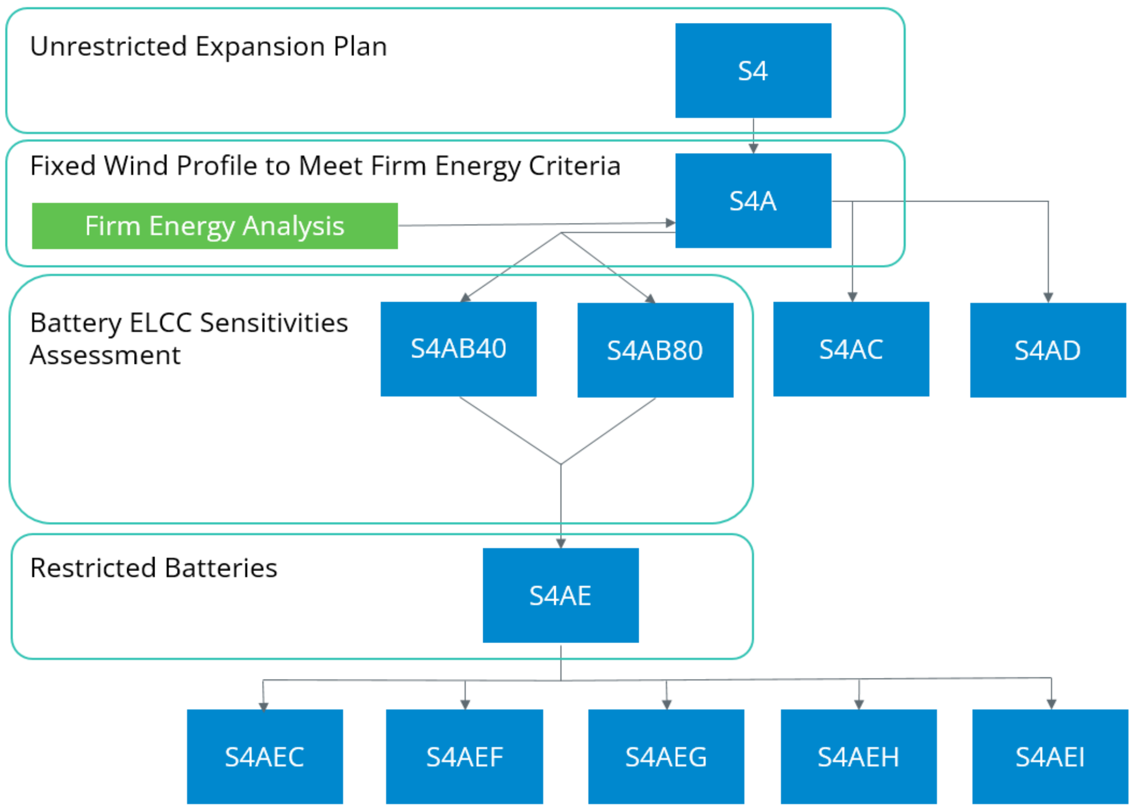


Figure 4: Scenario 4 Expansion Plan Sensitivity Analysis

The discussion of each Expansion Plan included in this section includes a summary of cost and emissions in consideration of Hydro's mandate to provide reliable electricity in an environmentally responsible manner at the lowest possible cost. A summary of the results is also provided in the following sections:

- Resource Requirements (Section 6.2.2.1);
- NPV Comparison (Section 6.2.2.2);

- Annual Emissions Comparison (Section 6.2.2.3); and
- Summary of Scenario 4 Expansion Plan Analysis (Section 6.2.2.4).

6.2.2.1 Resource Requirements

As mentioned previously, the first step in the analysis was to run an unrestricted Expansion Plan where known constraints were ignored and the Expansion Model was enabled to determine the Least-Cost Expansion Plan. The results of the Expansion Plan sensitivities are summarized within Table 20 to Table 31 and include the resources built, the firm capacity and firm energy contributions, the cumulative number of units of the resource required in each year (green highlighting indicates the addition of one or more units in that year), and the total firm capacity and firm energy corresponding to the Expansion Plan, reported on an annual basis. Table 20 to Table 31 show the results for 2030 through 2034, the end of the planning horizon. No expansion units are required prior to 2030 in any of the scenarios based on the assumption of maintaining existing thermal assets through the Bridging Period. The firm capacity added to the system in each year may be more than the requirement due to the size of the units selected as least-cost resource options. For example, a 50 MW unit might be the least-cost option to fill a 20 MW requirement.

6.2.2.1.1 Scenario 4: Unrestricted

Scenario 4 (Minimum Investment Required) includes Slow Decarbonization and assumes a LIL bipole EqFOR of 1%, as summarized in Table 4 in Section 6.1. The results of this Expansion Plan are summarized in Table 20.

Table 20: Scenario 4 (Unrestricted)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0					1
Wind 100 MW	22	350		1	2	3	3
Firm Capacity (MW)			0	176	198	220	362
Firm Energy (GWh)			0	350	700	1050	1050

In Scenario 4 (Unrestricted), the model builds Bay d'Espoir Unit 8, 100 MW of wind by 2031, followed by one 142 MW CT in 2034. In addition, the wind contribution increases to 300 MW by 2033. What this

Expansion Plan indicates is that Bay d'Espoir Unit 8 and a CT are the least-cost capacity resources, while wind is the most economic energy resource. However, while the Island Interconnected System capacity needs are met, the Expansion Model considers average hydrology, not firm hydrology, and therefore does not meet the firm energy criteria outlined in Section 3.0. The total cost, in terms of NPV, of this Expansion Plan is $2.4 billion and the annual emissions are estimated to be 25 kt by 2034 when the CT is added. Prior to this, the estimated annual emissions are minimal at 2 kt from 2031 to 2034.

6.2.2.1.2 Scenario 4A: Fixed Wind Profile

The second step of the analysis was to restrict the Expansion Model to include a fixed wind profile that ensures the firm energy criteria is met. As the wind contributes some capacity based on an assumed ELCC, this is expected to affect the capacity resources that were selected in Scenario 4 (Unrestricted). The results of this Expansion Plan are summarized in Table 21.

Table 21: Scenario 4A (Fixed Wind Profile)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
Wind 100 MW	22	350	1	4	4	4	4
Battery 50 MW	30[110]	0					1
Capacity			22	242	242	242	272
Firm Energy			350	1400	1400	1400	1400

In Scenario 4A (Fixed Wind Profile), 100 MW of wind is required in 2030, the year the Holyrood TGS is assumed to be retired. This escalates to 400 MW of wind in 2031, which is 100 MW more by the end of the study period than in Scenario 4 (Unrestricted). In terms of capacity resources, Bay d'Espoir Unit 8 is still selected by the model in 2031; however, instead of a CT in 2034, a 50 MW battery paired with the additional capacity supplied by the larger wind buildout is sufficient to meet capacity needs. By fixing the wind profile to meet Hydro's firm energy requirements, it results in an NPV increase of approximately $0.4 billion, for a total NPV of $2.8 billion[111] compared to Scenario 4 (Unrestricted). The annual emissions are minimal at 2 kt from 2031 onwards.

[110] An ELCC of 60% applied to a 50 MW battery results in 30 MW of firm capacity.
[111] Numbers may not add due to rounding.

This wind profile was maintained throughout the remainder of the analysis to ensure that firm energy criteria is being met in each Expansion Plan going forward. The only time the fixed profile was changed going forward is if the Expansion Plan was run with a different load forecast scenario (i.e., Accelerated Decarbonization or Reference Case), which requires an increase in energy requirements compared to Slow Decarbonization.

At this step in the process, the firm energy requirements have been resolved. Because Bay d'Espoir Unit 8, the CT, and batteries were determined to be cost-competitive capacity resources when testing Scenario 1 (Reference Case), similar sensitivities were run under Scenario 4 (Minimum Investment Required), as follows:

- **Sensitivity 4AB40**: Same as Sensitivity A (Fixed Wind Profile) with an assumed battery ELCC of 40% to capture the low-end of the assumed ELCC range;
- **Sensitivity 4AB80**: Same as Sensitivity A (Fixed Wind Profile) with an assumed battery ELCC of 80% to capture the high-end of the assumed ELCC range;
- **Sensitivity 4AC**: Same as Sensitivity A (Fixed Wind Profile) except for removing forced CT fuel burn-off in consideration of the potential for contract negotiation and/or shelf life extension negating this requirement; and
- **Sensitivity 4AD**: Same as Sensitivity A (Fixed Wind Profile) except for increasing all Hydro capital costs by 50% in consideration of potential cost overruns.

6.2.2.1.3 Scenario 4AB40: Fixed Wind Profile and Battery ELCC of 40%

The results of this Expansion Plan are summarized in Table 22.

Table 22: Scenario 4AB40 (Fixed Wind Profile and Battery ELCC of 40%)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0					1
Wind 100 MW	22	350	1	4	4	4	4
Firm Capacity (MW)			22	242	242	242	384
Firm Energy (GWh)			350	1400	1400	1400	1400

In Scenario 4AB40, the model builds Bay d'Espoir Unit 8 in 2031 and one 142 MW CT by the end of the study period. The wind requirements remain the same, as the wind profile remains fixed to meet the firm energy criteria. Similar to Scenario 1 (Reference Case), batteries with an ELCC of 40% were not selected as a least-cost option to meet Hydro's probabilistic planning criteria. The NPV of this Expansion Plan is $2.8 billion, equivalent to the cost of Scenario 4A (Fixed Wind). The annual emissions from 2031 onward are also estimated to be minimal at 2 kt until the CT is built when the annual emissions are estimated to increase to 25 kt in 2034.

6.2.2.1.4 Scenario 4AB80: Fixed Wind Profile and Battery ELCC of 80%

The results of this Expansion Plan are summarized in Table 23.

Table 23: Scenario 4AB80 (Fixed Wind Profile and Battery ELCC of 80%)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
Wind 100 MW	22	350	1	4	4	4	4
Battery 50 MW	40[112]	0					1
Firm Capacity (MW)			22	242	242	242	282
Firm Energy (GWh)			350	1400	1400	1400	1400

Scenario 4B80 Expansion Plan indicates Bay d'Espoir Unit 8 is required by 2031, followed by one 50 MW battery by 2034. The wind requirements remain the same, as the wind profile remains fixed to meet the firm energy criteria. This indicates that should the battery ELCC be at the high-end of the assumed range, it could prove to be an economical option to meet Hydro's probabilistic planning criteria. The NPV of this Expansion Plan is $2.7 billion, a decrease from Scenario 4A (Fixed Wind Profile) by $0.2 billion.[113] Varying battery ELCC between 40% and 80% has a negligible impact on the NPV analysis compared to Scenario 4A (Fixed Wind Profile) which assumes a battery ELCC of 60%. As a CT is not selected in this Expansion Plan, the annual emissions from 2031 onward are minimal, at approximately 2 kt.

[112] An ELCC of 80% applied to a 50 MW battery results in 40 MW of firm capacity.
[113] Numbers may not add due to rounding.

As discussed in Section 6.2.1.1.5, Hydro recognizes that battery technology is constantly improving, which is helping to reduce the costs that make them an attractive option to meet future load growth requirements; however, the incremental reliability benefits of batteries during an extended outage of the LIL are lacking. To prepare for potential future load growth, Hydro is committed to defining the battery ELCC as it applies to the Island Interconnected System, as well as better understanding the synergy between wind and batteries on Island reservoir storage and LIL deliveries to the Island to inform the next Resource Adequacy Plan update.

6.2.2.1.5 Scenario 4AC: Fixed Wind Profile and No Fuel Burn-Off

As described in Section 6.2.1.1.6, a sensitivity was designed to assess the influence of removing the fuel burn-off requirement. The results of this Expansion Plan are summarized in Table 24.

Table 24: Scenario 4AC (Fixed Wind Profile and No Fuel Burn-off)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
CT	141.6	0		1	1	1	2
Wind 100 MW	22	350	1	4	4	4	4
Firm Capacity (MW)			22	230	230	230	371
Firm Energy (GWh)			350	1400	1400	1400	1400

In Scenario 4AC, the model is choosing to build one 142 MW CT by 2031, following the retirement of existing thermal assets. With no fuel burn-off requirement, the CT becomes the least-cost capacity option, ahead of Bay d'Espoir Unit 8 and batteries. The wind requirements remain the same, as the wind profile remains fixed to meet the firm energy criteria. By reducing fuel burn-off, the NPV reduces to $2.7 billion, a $0.1 billion reduction compared to the NPV of Scenario 4A (Fixed Wind Profile).[114] The annual emissions from 2031 onward are minimal, ranging between 2 kt and 3 kt.

6.2.2.1.6 Scenario 4AD: Fixed Wind Profile and Hydro Capital Costs + 50%

Another sensitivity was included to reflect the potential for cost overruns of hydro projects. In this sensitivity, the capital cost of all hydroelectric resource options, including BDE Unit 8, was increased by 50%. The results of this Expansion Plan are summarized in Table 25.

[114] Numbers may not add due to rounding.

Table 25: Scenario 4AD (Fixed Wind Profile and Hydro Capital Costs + 50%)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
CT	141.6	0		1	1	1	2
Wind 100 MW	22	350	1	4	4	4	4
Firm Capacity (MW)			22	230	230	230	371
Firm Energy (GWh)			350	1400	1400	1400	1400

For Scenario 4AD, the model is choosing to build one 142 MW CT (which includes forced fuel burn-off as a conservative measure) by 2031, with a second 142 MW CT by 2034. The wind requirements remain the same, as the wind profile remains fixed to meet the firm energy criteria. As expected, Bay d'Espoir Unit 8 (and other hydro resource options) is not being selected due to the 50% increase in capital cost that was applied. The scenario has an NPV of \$3.0 billion, \$0.2 billion more than Scenario 4A (Fixed Wind Profile). The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 25 kt from 2031 until the second CT is constructed, which increases the annual emissions to 48 kt.

6.2.2.1.7 Scenario 4AE: Fixed Wind Profile and no Batteries

In the results of the Expansion Plan going forward, batteries have been eliminated as a resource option due to the reasons noted in Section 6.2.1.1.5. The results of this Expansion Plan, with a fixed wind profile and no batteries, is summarized in Table 26.

Table 26: Scenario 4AE (Fixed Wind Profile and No Batteries)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0					1
Wind 100 MW	22	350	1	4	4	4	4
Firm Capacity (MW)			22	242	242	242	384
Firm Energy (GWh)			350	1400	1400	1400	1400

The result of this scenario is the same as Scenario 4AB40—no batteries are built (since they are restricted); instead, the model chooses to build a CT in 2034. For this scenario, the NPV is \$2.8 billion, the same as Scenario 4A (Fixed Wind Profile)[115] where batteries were allowed. The annual emissions are estimated to be minimal at 2 kt from 2031 onward until the CT is built when the annual emissions are estimated to increase to 25 kt.

To test the Expansion Plan Scenario 4AE further, additional sensitivities were applied, including:

- **Sensitivity 4AEC**: A combination of Sensitivities AE and C to determine the impact of removing forced CT fuel burn-off;
- **Sensitivity 4AEF**: Same as Sensitivity AE with the additional restriction of limiting CT additions to 150 MW in consideration of current diesel fuel limitations on the Island;
- **Sensitivity 4AEG**: Same as Sensitivity AE except for increasing CT fuel costs by 50% in consideration of potential future volatility in fuel costs;
- **Sensitivity 4AEH**: Same as Sensitivity AE except for increasing CT capital costs by 50% in consideration of potential cost overruns; and
- **Sensitivity 4AEI**: Same as Sensitivity AE with the addition of the potential Newfoundland Power 25 MW CTs in 2028, 2029, and 2030, totalling 75 MW.

6.2.2.1.8 Scenario 4AEC: Fixed Wind Profile, No Batteries, and No Fuel Burn-Off

The results of Scenario 4AEC Expansion Plan are summarized in Table 27.

Table 27: Scenario 4AEC Fixed Wind Profile, No Batteries, and No Fuel Burn-Off

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
CT	141.6	0		1	1	1	2
Wind 100 MW	22	350	1	4	4	4	4
Firm Capacity (MW)			22	230	230	230	371
Firm Energy (GWh)			350	1400	1400	1400	1400

For Scenario 4AEC, the result is the same as Scenario 4AC, indicating the removal of the fuel burn-off requirement for the CT places the CT as the least-cost capacity option ahead of Bay d'Espoir Unit 8. The model builds one CT in 2031 and a second in 2034. This scenario indicates, again, how cost competitive

[115] Numbers may not add due to rounding.

the CT and Bay d'Espoir Unit 8 are. The NPV of this scenario is $2.7 billion, a $0.1 billion decrease from Scenario 4AE (Fixed Wind, No Batteries), which included the fuel burn-off requirement. Similar to Scenario 4AC, by removing the forced fuel burn-off the annual emissions from 2031 onward range from 2 kt to 3 kt.

6.2.2.1.9 Scenario 4AEF: Fixed Wind Profile, No Batteries, and Limit CTs

As mentioned in Section 4.4, fuel supply is a current concern; the costs associated with expanding the fuel supply could be prohibitive beyond a 150 MW CT addition. Therefore, an Expansion Plan was completed that was restricted to no more than one approximately 150 MW CT as a resource option. The results of this Expansion Plan are summarized in Table 28.

Table 28: Scenario 4AEF (Fixed Wind Profile, No Batteries, and Limit CTs)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0					1
Wind 100 MW	22	350	1	4	4	4	4
Firm Capacity (MW)			22	242	242	242	384
Firm Energy (GWh)			350	1400	1400	1400	1400

The Expansion Plan for Scenario 4AEF is the same as Scenario 4AE (Fixed Wind, No Batteries). In that case, the model only selected one CT, so limiting it to one CT had no effect. The NPV result of this scenario is $2.8 billion, the same as Scenario 4AE (Fixed Wind, No Batteries). This result indicates that restricting the number of CTs that can be installed on the system does not change the NPV. The annual emissions from 2031 onward are estimated to be 2 kt until the CT in 2034 is built, which leads to an increase to 25 kt.

For information on Scenario 4AEF transmission requirements, please refer to Section 7.3.

6.2.2.1.10 Scenario 4AEG: Fixed Wind Profile, No Batteries, and Increase Fuel Costs

Further testing of CTs as a resource option included increasing the fuel costs by 50% in recognition of increasing future demand, the potential for increased transportation requirements, the resulting potential cost increases associated with increased levels of carbon taxes, etc.[116] The results of this Expansion Plan is summarized in Table 29.

Table 29: Scenario 4AEG (Fixed Wind Profile, No Batteries, and Increase Fuel Costs)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0					1
Wind 100 MW	22	350	1	4	4	4	4
Firm Capacity (MW)			22	242	242	242	384
Firm Energy (GWh)			350	1400	1400	1400	1400

The results of Scenario 4AEG are the same as Scenario 4AE (Fixed Wind, No Batteries), which indicates that the CT is the least-cost capacity option after Bay d'Espoir Unit 8 even with an increase in fuel costs. The NPV of Scenario 4AEG is $2.9 billion, a $0.1 billion increase over Scenario 4AE (Fixed Wind, No Batteries). The annual emissions are estimated to be 2 kt from 2031 onward until the CT is built, which increases the annual emissions to 25 kt.

6.2.2.1.11 Scenario 4AEH: Fixed Wind Profile, No Batteries, and Increase CT Capital Costs

Another test included increasing the CT capital cost by 50%, in the event there are cost overruns or the AACE Class 3 cost estimate being completed as part of FEED is higher than the current estimate. The results of this Expansion Plan are summarized in Table 30.

Table 30: Scenario 4AEH (Fixed Wind Profile, No Batteries, and Increase CT Capital Costs)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0					1
Wind 100 MW	22	350	1	4	4	4	4
Firm Capacity (MW)			22	242	242	242	384
Firm Energy (GWh)			350	1400	1400	1400	1400

[116] For additional information, please refer to Attachment 4 to this Appendix.

The Expansion Plan for Scenario 4AEH is the same as Scenario 4AEF (Fixed Wind, No Batteries, and Limited CTs) and Scenario 4AE (Fixed Wind, No Batteries), indicating that either a 50% increase in fuel cost or a 50% increase in thermal capital cost does not change the Least-Cost Expansion Plan. The NPV of Scenario 4AEH is $3.0 billion, a $0.2 billion increase over Scenario AE (Fixed Wind, No Batteries). The annual emissions from 2031 onward are estimated to be 2 kt until the CT is built which increases the annual emissions to 25 kt.

6.2.2.1.12 Scenario 4AEI: Fixed Wind Profile, No Batteries, and Include NP CT Additions

As described in Section 6.2.1.1.12, a sensitivity was conducted to assess the influence of Newfoundland Power potentially building three 25 MW CTs. The results are summarized in Table 31.

Table 31: Scenario 4AEI (Fixed Wind Profile, No Batteries, and Include NP CT Additions)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
Wind 100 MW	22	350	1	4	4	4	4
Firm Capacity (MW)			22	242	242	242	242
Firm Energy (GWh)			350	1400	1400	1400	1400

In the case of Scenario 4AEI, where Newfoundland Power potentially builds 75 MW of additional generation Off-Avalon, the need for the second capacity resource is eliminated. Additional transmission upgrades would likely be required compared to Scenario AE, as all new capacity is located Off-Avalon. The NPV of this scenario is $2.4 billion; however, the cost of the additional 75 MW is not included. The annual emissions are estimated to be 2 kt from 2031 onwards, as the CT on the Avalon is no longer being selected. However, this does not include the emissions from Newfoundland Power's proposed CTs.

How the fueling of the potential 75 MW CTs would be supplied in addition to Hydro's existing CTs and any future new CTs requires further study. For information on Scenario 4AEI transmission requirements, please refer to Section 7.3.

6.2.2.2 NPV Comparison

The total Expansion Plan costs presented herein include generation capital costs, fixed and variable O&M costs, and fuel costs. Export market revenue has not been included and does not vary significantly for a given load forecast.[117] Financing costs associated with new capital spending are also not included. The costs of transmission requirements are also not considered in the NPV comparison; however, these costs are addressed in Section 7.3 and included in the rate impact analysis in Section 7.4.1. The annual costs from the PLEXOS model are translated to an NPV using the WACC to discount future financial impacts to today's value. Because expansion units will continue to operate well beyond the 2034 planning horizon (the economic life of the resources considered in this study ranges from 20 to 60 years), the objective function used in the PLEXOS model sums the present values of costs beyond the final horizon year. It is assumed that annualized build costs and operational costs are extended into perpetuity beyond the final year of the modelling horizon; these are discounted and then summed to arrive at the total NPV cost presented.

Chart 12 compares the NPV of the Scenario 4 (Minimum Investment Required) sensitivities. This section is intended to demonstrate the cost impact of each sensitivity to help determine the Least-Cost Expansion Plan that meets Hydro's probabilistic planning criteria and firm energy criteria.

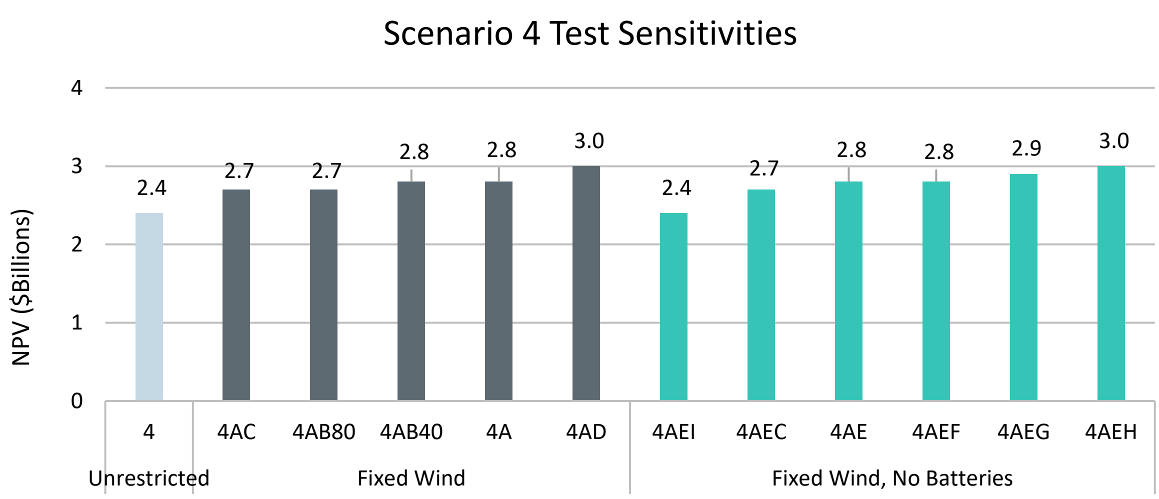


Chart 12: NPV Scenario 4 (Minimum Investment Required) Sensitivity Comparison[118]

[117] It is likely that there will be market revenue associated with resource options that generate energy that could marginally decrease the NPV of each scenario, however to avoid counting on a potential market revenue forecast that may not occur, it was removed from this analysis.
[118] All costs are presented in 2024 CDN.

The NPV for Scenario 4AC and Scenario 4AEC are low because the forced fuel burn-off has been removed. The savings in these scenarios compared to other scenarios in this analysis are not due to a reduction in expansion costs but through improved fuel management practices. The NPV for Scenario 4AEI is also low, not due to a reduction in expansion costs but because it does not account for the potential costs incurred by Newfoundland Power for the construction of three 25 MW CTs.

6.2.2.3 Annual Emissions Comparison

Chart 13 compares the annual emissions of CO_2e (kt per year) for each of the Scenario 4 (Minimum Investment Required) sensitivities to help identify the emissions impact of each sensitivity applied.

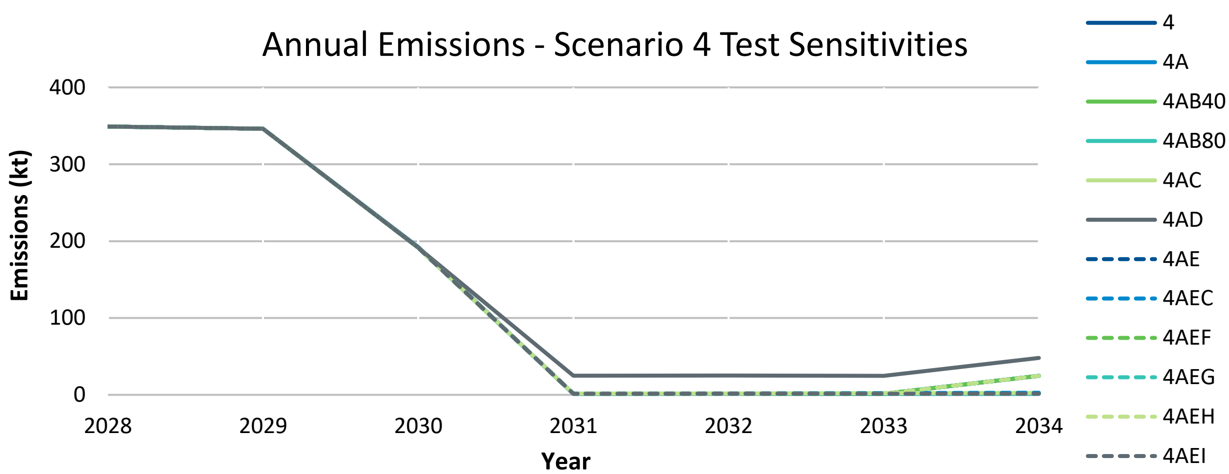


Chart 13: Comparison of Scenario 4 Sensitivities Annual Emissions[119]

As Chart 13 demonstrates, it is evident that the estimated annual emissions decrease dramatically in all cases upon retirement of existing thermal assets (Holyrood TGS, Hardwoods GT, and Stephenville GT). Emissions up to 2029 are estimated to be approximately 350 kt per year, dropping to no more than 48 kt (which corresponds to Scenario 4AD that builds the most CTs and assumes an annual fuel burn-off requirement). This is an approximately 86% reduction in fuel emissions that may be achieved within the study period once the Holyrood TGS is retired. Should system conditions differ from that assumed in this analysis, annual emissions could be more than presented.

[119] The full time horizon of the study period was limited to 2028 to 2034 to give better visibility to the differing emissions between scenarios once the Holyrood TGS retired in 2030. Annual emissions from 2024 through 2028 were approximately 350 kt for all sensitivities.

6.2.2.4 Summary of Scenario 4 (Minimum Investment Required) Expansion Plans

In total, 11 sensitivities were applied to Scenario 4 (Minimum Investment Required), which are summarized in Table 32. The capacity and energy builds are included in Table 32 based on the year required.

Table 32: Summary of Scenario 4 Expansion Plans

Scenario	Description	Capacity Build				Energy Build					NPV[120] ($Billions)	Max. Emissions[121] (kt)
		2031	2032	2033	2034	2030	2031	2032	2033	2034		
4	Unrestricted	BDE Unit 8			1 CT		1 Wind	1 Wind	1 Wind		2.4	25
4A	Fixed Wind Profile	BDE Unit 8			1 Battery	1 Wind	3 Wind				2.8	2
4AB40	Fixed Wind, Batteries ELCC 40%	BDE Unit 8			1 CT	1 Wind	3 Wind				2.8	25
4AB80	Fixed Wind, Batteries ELCC 80%	BDE Unit 8			1 Battery	1 Wind	3 Wind				2.7	2
4AC	Fixed Wind, No Fuel Burn-Off for CT	1 CT			1 CT	1 Wind	3 Wind				2.7	3
4AD	Fixed Wind, Hydro Capital Cost +50%	1 CT			1 CT	1 Wind	3 Wind				3.0	48
4AE	Fixed Wind, No Batteries	BDE Unit 8			1 CT	1 Wind	3 Wind				2.8	25
4AEC	Fixed Wind, No Batteries, No Fuel Burn-Off for CT	1 CT			1 CT	1 Wind	3 Wind				2.7	3
4AEF	Fixed Wind, No Batteries, Limit CT to 150 MW	BDE Unit 8			1 CT	1 Wind	3 Wind				2.8	25
4AEG	Fixed Wind, No Batteries, Fuel Cost +50%	BDE Unit 8			1 CT	1 Wind	3 Wind				2.9	25
4AEH	Fixed Wind, No Batteries, CT Capital Cost +50%	BDE Unit 8			1 CT	1 Wind	3 Wind				3.00	25
4AEI	Fixed Wind, No Batteries, NP CTs (75 MW)	BDE Unit 8				1 Wind	3 Wind				2.4[122]	2[123]

[120] Exclusive of transmission upgrade costs and market export opportunities.
[121] Maximum emissions (kt) from 2031 onwards.
[122] Excludes the cost of Newfoundland Power's 75 MW CTs.
[123] Excluding the emissions of Newfoundland Power's 75 MW CTs.

6.2.3 Discussion: Sensitivities Key Learnings

Throughout the sensitivity analysis on Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required), a number of key learnings were determined regarding both energy and capacity requirements during the study period. These learnings are discussed further within this section.

6.2.3.1 Energy Requirements

For each scenario tested, energy is required within the ten-year planning horizon to meet both Reference Case and Slow Decarbonization scenarios. In addition:

- The amount of energy resources required depends on the Expansion Plan scenario and corresponding load forecast scenario;
- Wind was consistently selected as the least-cost energy source compared to all other energy resource options available for consideration in the Expansion Model;
- Solar expansion resources were not selected by the model in any sensitivity; and
- The expansion planning analysis is done on an average inflow basis, resulting in the Expansion Model not meeting Hydro's firm energy criteria.[124]

Based on this, a fixed wind generation build profile (Sensitivity A) was applied throughout the remaining analysis to ensure the firm energy criteria were met.

6.2.3.2 Capacity Requirements

In all scenarios tested, capacity is also required within the ten-year planning horizon, even under the Slow Decarbonization scenario. Specifically:

- The results demonstrate that for Scenario 1 (Reference Case), two large (approximately 150 MW) capacity resource options are required by 2031, following the retirement of the Holyrood TGS, Hardwoods GT, and Stephenville GT in the first quarter of 2030, which total 590 MW of capacity that is being removed from the Island Interconnected System.

[124] The PLEXOS Expansion Model solves the capacity expansion optimization; however, the model considers average hydrology, which would not meet Hydro's firm energy criteria.

- For Scenario 4 (Minimum Investment Required), two large capacity resource options are still required, with 150 MW needed by 2031 and an additional 150 MW at the end of the study period, in 2034.
- The Expansion Model selects batteries for capacity when assigned an assigned an ELCC of 60% and 80%; however, under the Reference Case and Slow Decarbonization load forecasts, the model does not select batteries when the ELCC applied is 40%.
    - Batteries would be of limited use during a prolonged LIL outage during the winter period, as there would be limited energy to allow for recharging of the batteries, particularly at higher penetrations.
- For both scenarios tested, Bay d'Espoir Unit 8 is consistently being chosen by the model as the least-cost expansion option for the Island Interconnected System; however, CTs are cost-competitive with Bay d'Espoir Unit 8. When tested further under both Scenarios 1 (Reference Case) and 4 (Minimum Investment Required):
    - The removal of the forced annual fuel burn-off made CTs the preferred expansion option;
    - A 50% increase in the capital cost of hydraulic expansion options made CTs the preferred expansion option;
    - A 50% increase in the CT fuel cost did not affect the results of the Expansion Plan; and
    - A 50% increase in the capital cost of the CT did not affect the results of the Expansion Plan.

  These results demonstrate that the two capacity resource options are close to each other in terms of total costs and are both far less expensive than the next resource option in the supply stack.
- In no sensitivities were Island Pond, Round Pond, or Portland Creek chosen to supply energy or capacity, due to the very high costs of these projects.

6.3 Expansion Plan Results for all Scenarios

Following the analysis of the sensitivities on Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required), the Expansion Plans for the remaining scenarios (Scenarios 2, 3, 5, 6, 7, and 8) were completed by applying sensitivity AEF (which includes the fixed wind profile, no batteries, and limits CTs) to approximately 150 MW in consideration of current fuel limitations. Each Expansion Plan ran includes the NPV associated with each sensitivity applied and the resultant emissions in consideration of Hydro's mandate to provide reliable electricity in an environmentally responsible manner at the lowest possible cost. For comparison purposes, the results are summarized in the following sections:

- Resource Requirements (Section 6.3.1)
- Net Present Value Comparison (Section 6.3.2);
- Annual Emissions Comparison (Section 6.3.3); and
- Summary of Scenario 4 Expansion Plan Analysis (Section 6.3.4).

The firm capacity added to the system in each year may be more than the requirement, due to the size of the units selected as least-cost resource options. For example, a 50 MW unit might be the least-cost option to fill a 20 MW requirement.

6.3.1 Resource Requirements

6.3.1.1 Scenario 2AEF: Accelerated Decarbonization, LIL Bipole EqFOR 5%

Scenario 2AEF includes the Accelerated Decarbonization scenario and assumes a LIL bipole EqFOR of 5%, as summarized in Table 4 in Section 6.1. This scenario was used to determine resource requirements if load growth on the Island accelerates more rapidly than anticipated in Scenario 1 (Reference Case). The results of this Expansion Plan are summarized in Table 33.

Table 33: Scenario 2AEF (Accelerated Decarbonization and 5% LIL Bipole EqFOR)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	1	1
CAT Unit 3	68.2	0		1	1	1	1
Proxy Capacity	50	0		1	1	2	3
Wind 100 MW	22	350	3	5	6	7	7
Firm Capacity (MW)			66	524	546	618	668
Firm Energy (GWh)			1050	1750	2100	2450	2450

The Scenario 2AEF Expansion Plan requires Bay d'Espoir Unit 8, one 142 MW CT, Cat Arm Unit 3, and a 50 MW proxy capacity, all by 2031. The proxy capacity requirement increases to three 50 MW units by 2034, resulting in a total additional capacity requirement of 668 MW by 2034. The wind profile remains fixed, requiring up to 700 MW of wind by 2034, providing approximately 2.5 TWh of energy. Should this scenario materialize and fuel constraints remain, Hydro will be challenged to meet reliability requirements, given the timeline to construct new generation. Additional analysis would be required to determine what the proxy capacity could constitute; it is likely that further extension of the Holyrood TGS and other thermal assets beyond 2030 would be required until new assets could be constructed. If high growth were to occur on the Island Interconnected System, the NPV is estimated to be $8.9 billion. The estimated annual emissions are expected to range from 35 kt to 54 kt between 2031 and 2034.

6.3.1.2 Scenario 3AEF: Slow Decarbonization, 5% LIL Bipole EqFOR

Scenario 3AEF includes the Slow Decarbonization scenario and assumes a LIL bipole EqFOR of 5%, as summarized in Table 4 in Section 6.1. This scenario was used to capture resource requirements if load growth on the Island Interconnected System increases more slowly than anticipated in Scenario 1 (Reference Case). The results of this Expansion Plan are summarized in Table 34.

Table 34: Scenario 3AEF (Slow Decarbonization and 5% LIL Bipole EqFOR)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	1	1
CAT Unit 3	68.2	0					1
Wind 100 MW	22	350	1	4	4	4	4
Firm Capacity (MW)			22	384	384	384	452
Firm Energy (GWh)			350	1400	1400	1400	1400

Scenario 3AEF requires Bay d'Espoir Unit 8, one 142 MW CT by 2031, and the addition of Cat Arm Unit 3 by 2034, resulting in a total of 452 MW of additional capacity required by 2034. 400 MW of wind, providing 1.4 TWh of energy, is required for the Slow Decarbonization scenario. Compared to Scenario 4AEF (Minimum Investment Required), should LIL reliability not meet the highly reliable scenario (1% LIL bipole EqFOR), and be closer to the expected case (5% LIL bipole EqFOR), the requirement for the 142 MW CT advances from 2034 to 2031 with an additional 68 MW of capacity required by the end of the study period. Should lower load growth materialize and a LIL bipole EqFOR of 5% occur, the NPV of this Expansion Plan is estimated to be $4.1 billion. Compared to Scenario 4AEF (Minimum Investment Required) there is potential to reduce the NPV by $1.3 billion if LIL reliability can achieve a 1% LIL bipole EqFOR compared to a 5% LIL bipole EqFOR. The estimated annual emissions beyond 2031 are estimated to be approximately 25 kt.

6.3.1.3 Scenario 5AEF: Accelerated Decarbonization, 10% LIL Bipole EqFOR

Scenario 5AEF includes the Accelerated Decarbonization scenario combined with a 10% LIL bipole EqFOR, as summarized in Table 4 in Section 6.1. This scenario is intended to bookend the Expansion Plan scenarios by identifying the Maximum Investment Required on the Island Interconnected System. The results of this Expansion Plan are included in Table 35.

Table 35: Scenario 5AEF (Accelerated Decarbonization and 10% LIL Bipole EqFOR)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	1	1
CAT Unit 3	68.2	0		1	1	1	1
Proxy Capacity	50	0		2	2	3	5
Wind 100 MW	22	350	3	5	6	7	7
Firm Capacity (MW)			66	574	596	668	768
Firm Energy (GWh)			1050	1750	2100	2450	2450

Scenario 5AEF generation requirements consist of Bay d'Espoir Unit 8, a 142 MW CT, Cat Arm Unit 3, and two 50 MW proxy capacity units by 2031. The proxy capacity requirements increase to five 50 MW units by the end of the study period, resulting in a total of 768 MW of additional capacity required by the end of the study period. The fixed wind profile remains consistent to meet the energy requirements for the Accelerated Decarbonization scenario. Should this scenario occur, the NPV is estimated to be $10.1 billion and the annual emission is estimated to be between 45 kt and 74 kt from 2031 onward.

6.3.1.4 Scenario 6AEF: Accelerated Decarbonization, 1% LIL Bipole EqFOR

Scenario 6AEF includes the Accelerated Decarbonization scenario combined with a 1% LIL bipole EqFOR, as summarized in Table 4 in Section 6.1. This scenario helps to identify what resource options are required mainly due to policy driven growth (e.g., electrification) by assuming high Island growth and a highly reliable LIL. The results of this Expansion Plan are included in Table 36.

Table 36: Scenario 6AEF (Accelerated Decarbonization and 1% LIL Bipole EqFOR)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0				1	1
CAT Unit 3	68.2	0		1	1	1	1
Wind 100 MW	22	350	3	5	6	7	7
Firm Capacity (MW)			66	333	355	518	518
Firm Energy (GWh)			1050	1750	2100	2450	2450

Scenario 6AEF Expansion Plan identifies the requirement for Bay d'Espoir Unit 8 and Cat Arm Unit 3 by 2031 followed by one 142 MW CT by 2033. As the Accelerated Decarbonization scenario has high wind requirements to meet energy demand, the assumed capacity contribution of the wind is contributing towards the capacity need in 2031. This results in the slight delay of the need for the 142 MW CT and the earlier requirement of a smaller capacity resource—Cat Arm Unit 3. Therefore, in order to achieve policy-driven growth, the addition of approximately 520 MW of capacity is required by the end of the study period. Directly comparing against Scenario 5AEF, a highly reliable LIL (1% LIL bipole EqFOR) compared to a LIL bipole EqFOR of 10%, results in approximately 250 MW less capacity required over the study period if the LIL is highly reliable. Should high load growth occur in combination with a highly reliable LIL, the NPV is estimated to be $6.6 billion. The annual emissions beyond 2031 are estimated to be up to 25 kt.

6.3.1.5 Scenario 7AEF: Slow Decarbonization, 5% LIL Bipole EqFOR, 0.1 LOLE

Scenario 7AEF includes the Slow Decarbonization scenario combined with a 5% LIL bipole EqFOR, as summarized in Table 4 in Section 6.1. This scenario was developed to understand the resources required to meet a more stringent planning criteria of 0.1. LOLE than what is being proposed in the other scenarios considered in this study. The results of this Expansion Plan are included in Table 37.

Table 37: Scenario 7AEF (Slow Decarbonization, 5% LIL Bipole EqFOR, 0.1 LOLE)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	1	1
CAT Unit 3	68.2	0		1	1	1	1
Proxy Capacity	50	0		1	2	2	3
Wind 100 MW	22	350	1	4	4	4	4
Firm Capacity (MW)			22	502	552	552	602
Firm Energy (GWh)			350	1400	1400	1400	1400

In this scenario, Bay d'Espoir Unit 8, one 142 MW CT, Cat Arm Unit 3, and one 50 MW proxy capacity source are required by 2031, escalating to three 50 MW proxy capacity sources by the end of the study period. Comparing directly against Scenario 3AEF (which also assumes the Slow Decarbonization and a 5% LIL Bipole EqFOR but the existing planning criteria of 2.8 LOLH), approximately 150 MW of additional capacity is required by the end of the study period. This scenario results in an estimated NPV of $6.4 billion. Compared to Scenario 3AEF, the NPV associated with increasing the level of reliability on the Island Interconnected System to achieve 0.1 LOLE is estimated to be approximately $2.3 billion. The annual emissions from 2031 onward are estimated to range between 35 kt and 55 kt.

6.3.1.6 Scenario 8EF: Reference Case, LIL Energy-Only

Scenario 8AEF includes the Reference Case and considers the LIL to be an energy only line; meaning it does not provide any capacity benefit to the Island Interconnected System. The results of the Expansion Plan are included in Table 38.

Table 38: Scenario 8AEF (Reference Case, LIL Energy-Only)

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	1	1
CAT Unit 3	68.2	0		1	1	1	1
Proxy Capacity	50	0		3	3	4	5
Wind 100 MW	22	350	2	4	5	5	5
Firm Capacity (MW)			44	552	624	674	724
Firm Energy (GWh)			700	1400	1750	1750	1750

Scenario 8AEF Expansion Plan requires the addition of Bay d'Espoir Unit 8, one 142 MW CT, Cat Arm Unit 3, and three 50 MW proxy capacity resources by 2031, escalating to five 50 MW proxy capacity resources by the end of the study period, resulting in a total capacity requirement of 724 MW by the end of the study period. The fixed wind profile to meet firm energy requirements under the Reference Case includes 500 MW of wind by the end of the study period, providing approximately 1.8 TWh of energy. The NPV for this scenario is estimated to be $8.2 billion. The annual emissions are estimated to range from 54 kt to 74 kt from 2031 onward.

6.3.2 Net Present Value Comparison

Chart 14 compares the NPV of all scenarios identified in Section 6.1 to illustrate the range in costs associated with different load forecasts, LIL bipole EqFOR rates, and planning criteria. The "AEF" Sensitivity (fixed wind, no batteries, and restricting CT additions to approximately 150 MW) was applied to each scenario to ensure the firm energy planning criteria was met and limitations with respect to batteries and fuel supply for CTs were accounted for. The NPV is grouped by Island Interconnected System load forecast and range from lowest NPV to highest NPV within each of the three load forecast scenarios.

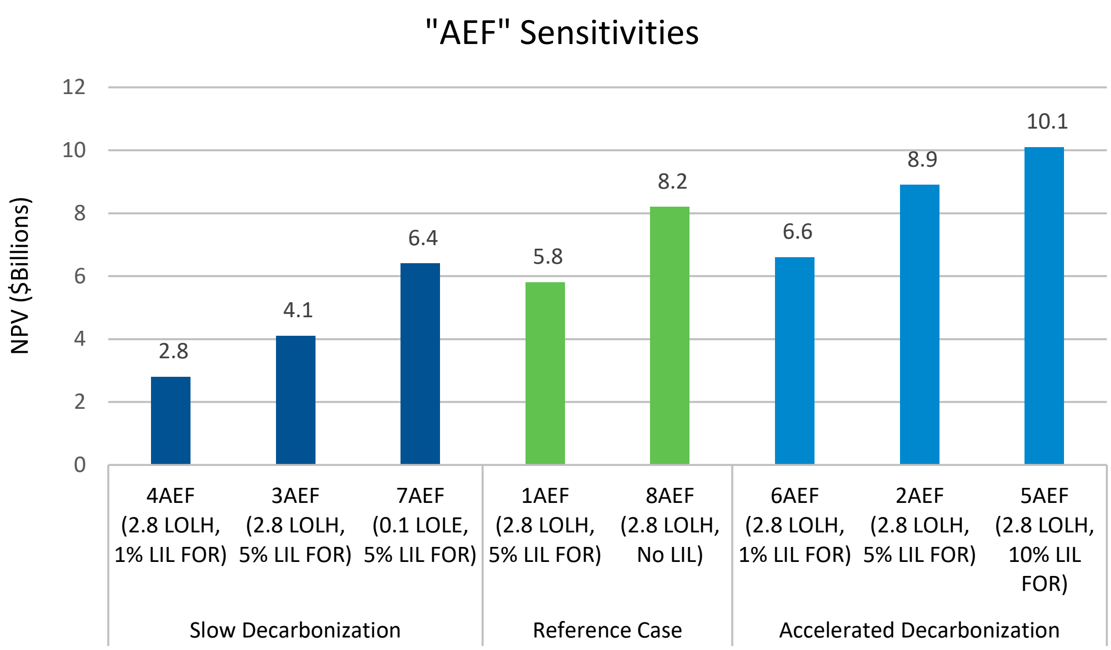


Chart 14: NPV Comparison: Expansion Plan AEF Scenarios[125]

The total Expansion Plan costs presented herein include generation capital costs, fixed and variable O&M costs, and fuel costs. Export market revenue has not been included and does not vary significantly for a given load forecast.[126] Financing costs associated with new capital spending are also excluded. The costs of transmission requirements are also not considered in the NPV comparison; however, these costs are addressed in Section 7.3 and include in the rate impact analysis in Section 7.4.1. The annual costs from the PLEXOS model are translated to a NPV using the WACC to discount future financial impacts to today's value. Because expansion units will continue to operate well beyond the 2034 planning horizon (the economic life of the resources considered in this study range from 20 to 60 years), the objective function used in the PLEXOS model sums the present values of costs beyond the final

[125] All costs are presented in 2024 CDN.
[126] It is likely that there will be market revenue associated with resource options that generate energy that could marginally decrease the NPV of each scenario; however, to avoid counting on a potential market revenue forecast that may not occur, it was removed from this analysis.

horizon year. It is assumed that annualized build costs and operational costs are extended into perpetuity beyond the final year of the modelling horizon and are discounted and then summed to arrive at the total NPV cost presented.

For some of these scenarios, a proxy capacity resource was selected, especially for the scenarios that included Accelerated Decarbonization. There is potential that costs assumed for the proxy capacity resource would likely be less, should actual identified capacity resources be more affordable, thereby reducing the NPV for those scenarios.

6.3.3 Emission Comparison

Chart 15 compares the annual emissions of CO_2e for each of the eight scenarios with Sensitivity "AEF" (fixed wind, no batteries, and restricting CT additions to approximately 150 MW) applied to indicate the range of emissions across each scenario.

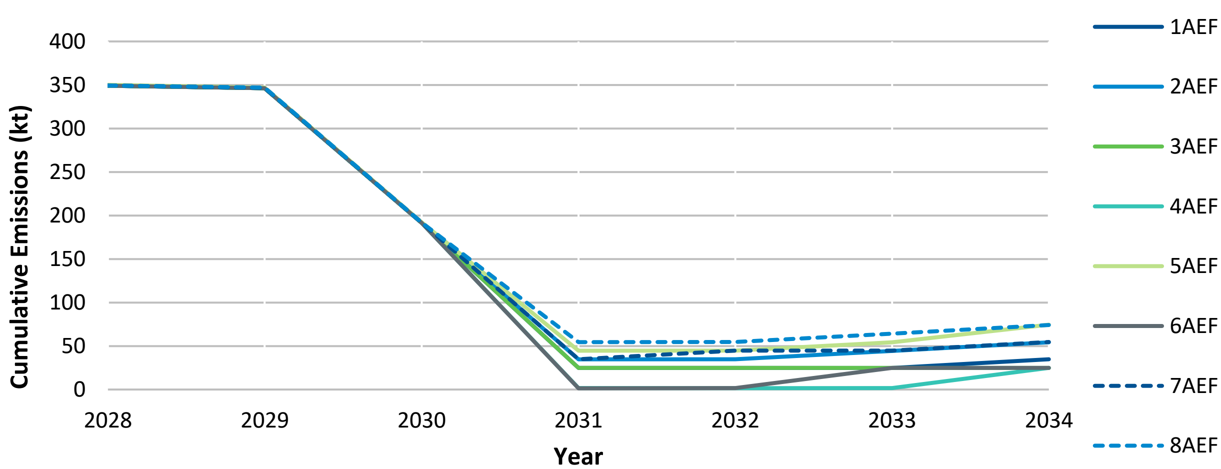


Chart 15: Annual Emissions (kt) for all "AEF" Sensitivities[127]

As Chart 15 demonstrates, it is evident that the estimated annual emissions decrease dramatically in all cases upon retirement of existing thermal assets (Holyrood TGS, Hardwoods GT, and Stephenville GT). Emissions up to 2029 are estimated to be approximately 350 kt per year, decreasing to between 25 kt and 74 kt.

[127] The full time horizon of the study period was limited to 2028 to 2034 to give better visibility to the differing emissions between scenarios once the Holyrood TGS retired in 2030. Annual emissions from 2024 through 2028 were approximately 350 kt for all sensitivities.

The total emissions during the study period are provided in Chart 16. The Expansion Plan scenarios are not shown in order, rather grouped by Island Interconnected System load forecast first and then provided in ascending order of emissions.

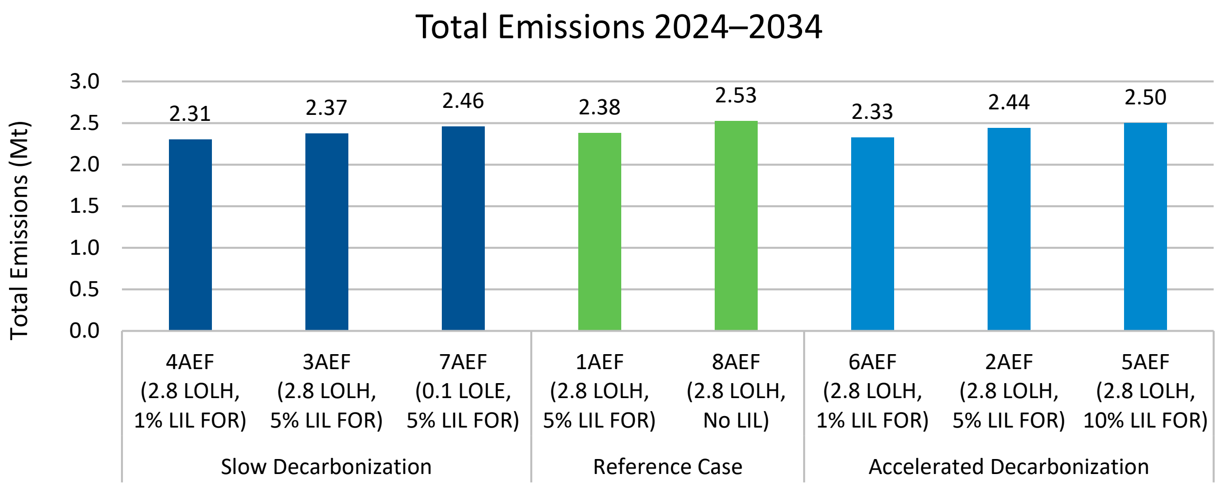


Chart 16: Total Emissions (Mt) over Study Period

Over the course of the study period, there is minimal difference in emissions between all scenarios considered. The minimum total emissions are 2.31 Mt from Scenario 4AEF (Minimum Investment Required) and the maximum estimated total emissions is 2.53 Mt from Scenario 8AEF. The main driver for emissions during this period is the emissions from the Holyrood TGS. Emissions in the period that the Holyrood TGS is still in service (2024 to 2030) account for over 90% of the emissions from 2024 to 2034.

Should system conditions differ from what is assumed in this analysis, annual emissions could be more than presented.

6.3.4 Summary of Expansion Plans

This section summarizes the Expansion Plans corresponding to all eight scenarios with Sensitivities "AEF" applied and are summarized in Table 39. The capacity and energy builds are included in Table 39 based on the year required.

Table 39: Summary of "AEF" Expansion Plans[128,129]

Scenario	Description	Capacity Build				Energy Build					NPV[130] ($Billions)	Max.[131] Emissions[2] (kt)
		2031	2032	2033	2034	2030	2031	2032	2033	2034		
1AEF	Reference Case, LIL Bipole EqFOR 5%, Planning Criteria 2.8 LOLH	BDE Unit 8, 1 CT, CAT Unit 3			1 Proxy	2 Wind	2 Wind	1 Wind			5.8	35
2AEF	Accelerated Decarbonization, LIL Bipole EqFOR 5%, Planning Criteria 2.8 LOLH	BDE Unit 8, 1 CT, CAT Unit 3, 1 Proxy		1 Proxy	1 Proxy	3 Wind	2 Wind	1 Wind	1 Wind		8.9	54
3AEF	Slow Decarbonization LIL Bipole EqFOR 5%, Planning Criteria 2.8 LOLH	BDE Unit 8, 1 CT			CAT Unit 3	1 Wind	3 Wind				4.1	25
4AEF	Slow Decarbonization, LIL Bipole EqFOR 1%, Planning Criteria 2.8 LOLH	BDE Unit 8			1 CT	1 Wind	3 Wind				2.8	25
5AEF	Accelerated Decarbonization, LIL Bipole EqFOR 10%, Planning Criteria 2.8 LOLH	BDE Unit 8, 1 CT, CAT Unit 3, 2 Proxy		1 Proxy	2 Proxy	3 Wind	2 Wind	1 Wind	1 Wind		10.1	74
6AEF	Accelerated Decarbonization, LIL Bipole EqFOR 1%, Planning Criteria 2.8 LOLH	BDE Unit 8, CAT Unit 3		1 CT		3 Wind	2 Wind	1 Wind	1 Wind		6.6	25
7AEF	Slow Decarbonization, LIL Bipole EqFOR 5%, Planning Criteria 0.1 LOLE	BDE Unit 8, 1 CT, CAT Unit 3, 1 Proxy	1 Proxy		1 Proxy	1 Wind	3 Wind				6.4	55
8AEF	Reference Case, LIL Provides no Capacity Benefit, Planning Criteria 2.8 LOLH	BDE Unit 8, 1 CT, CAT Unit 3 3 Proxy		1 Proxy	1 Proxy	2 Wind	2 Wind	1 Wind			8.2	74

[128] All costs are presented in 2024 CDN.
[129] Removes batteries and limits CTs.
[130] Exclusive of transmission upgrade costs and market export opportunities.
[131] Maximum emissions (kt) from 2031 onwards.

6.3.5 Discussion: Expansion Plan Scenarios

A number of outcomes were determined regarding both energy and capacity requirements during the study period (2024 though 2034) and are discussed further within this section.

6.3.5.1 Energy Requirements

As the PLEXOS model considers a need for new energy resources based on average hydrological conditions rather than critical dry periods, Hydro fixed the energy resource additions in the model to ensure its firm energy criteria was met. Therefore, the energy resource additions (in this case wind) across scenarios varied only by the load forecast scenario applied. The energy resource additions for the three Island Interconnected System load forecast scenarios are summarized as follows:

- **Slow Decarbonization**: Initial firm energy requirement begins in 2030, upon the retirement of the Holyrood TGS, totaling 100 MW of wind, providing approximately 0.35 TWh of energy. The firm energy requirement escalates to a total of 400 MW of wind by the end of the study period, providing approximately 1.40 TWh of energy to the Island Interconnected System. This fixed wind profile was applied against Expansion Plan Scenarios 3AEF, 4AEF (Minimum Investment Required), and 7AEF.
- **Reference Case**: Initial firm energy requirement begins in 2030, upon the retirement of the Holyrood TGS, totaling 200 MW of wind, providing approximately 0.7 TWh of energy. The firm energy requirement escalates to a total of 500 MW of wind by the end of the study period, providing approximately 1.75 TWh of energy. This fixed wind profile was applied against Expansion Plan Scenarios 1AEF (Reference Case) and 8AEF.
- **Accelerated Decarbonization**: Initial firm energy requirement begins in 2030, upon the retirement of the Holyrood TGS, totaling 300 MW of wind, providing approximately 1.05 TWh of energy. The firm energy requirement escalates to a total of 700 MW of wind by the end of the study period, providing approximately 2.45 TWh of energy. This fixed wind profile was assumed for Expansion Plan Scenarios 2AEF, 5AEF, and 6AEF.

6.3.5.2 Capacity Requirements

In all Expansion Plan scenarios, capacity is also required within the ten-year planning horizon to meet reliability requirements. The key learnings from the Expansion Plan scenarios are summarized in Sections 6.3.5.2.1 to 6.3.5.2.4.

6.3.5.2.1 Resource Options

The least-cost capacity resource options for all scenarios remain as Bay d'Espoir Unit 8 and the CT. Cat Arm Unit 3 is consistently being selected where additional capacity is required beyond the two least-cost options (Bay d'Espoir Unit 8 and the CT). Island Pond, Round Pond, and Portland Creek were excluded from the analysis based on their high cost. It was assumed that other capacity options (e.g., another CT) would be available at a much lower cost; this was represented in the model as a 50 MW proxy capacity option.

6.3.5.2.2 Planning Criteria Comparison

Comparing Scenarios 3AEF and 7AEF, an additional 150 MW of generation would be required to achieve a more stringent planning criteria of 0.1 LOLE by the end of the study period. The NPV cost of the Expansion Plan increased by 55% between Scenarios 3AEF and 7AEF.

6.3.5.2.3 Load Forecast Comparison

Comparing Scenarios 1AEF (Reference Case), 2AEF (Accelerated Decarbonization), and 3AEF (Slow Decarbonization), which differ only by the load forecast scenario applied, a minimum capacity of approximately 385 MW (Slow Decarbonization) to 525 MW (Accelerated Decarbonization) is required by 2031, following the retirement of the Holyrood TGS, Hardwoods GT, and Stephenville GT. The requirement for additional capacity increases from 450 MW (Slow Decarbonization) to 670 MW (Accelerated Decarbonization) by 2034. The NPV cost of the Reference Case and Accelerated Decarbonization scenarios are higher than the Slow Decarbonization scenario by a factor of 1.4 and 2.2, respectively.

Comparing Scenarios 4AEF (Minimum Investment Required) and 6AEF, which both consider a LIL bipole EqFOR of 1%, an additional 90 MW of capacity is required by 2031, should load growth increase from the Slow Decarbonization to the Accelerated Decarbonization scenario. By 2034, the additional requirement capacity increases to approximately 135 MW. The NPV cost of Scenario 6AEF is 2.4 times the cost of Scenario 4AEF.

6.3.5.2.4 LIL Reliability Comparison

Comparing Scenarios 3AEF and 4AEF (Minimum Investment Required), which both consider the Slow Decarbonization scenario but differ by LIL bipole EqFOR applied (5% for Scenario 3AEF and 1% for Scenario 4AEF), an additional 140 MW of capacity is required by 2031, should the LIL bipole EqFOR be

5% rather than 1%. By 2034, the difference reduces to approximately 70 MW of capacity as Scenario 4AEF (Minimum Investment Required) Expansion Plan is adding a 142 MW CT in that same year, thus reducing the impact of the different LIL bipole EqFOR assumptions in that year. The NPV cost of Scenario 3AEF is 1.5 times the cost of Scenario 4AEF.

Comparing Scenarios 1AEF and 8AEF, which both consider the Reference Case but have difference assumptions about the LIL, an additional 100 MW of capacity is required by 2031 for the case where the LIL is assumed to provide no capacity benefit to the Island Interconnected System compared to the case where the LIL is assumed to have a 5% LIL bipole EqFOR. The delta increases to 200 MW by 2034. The NPV cost of Scenario 8AEF is 1.4 times Scenario 1AEF.

Comparing Scenarios 2AEF, 5AEF, and 6AEF, which all consider the Accelerated Decarbonization scenario but differ by the LIL bipole EqFOR (5%, 10%, and 1%, respectively), a range of 335 MW (1% LIL bipole EqFOR) to 575 MW (10% LIL bipole EqFOR) is required by 2031 to meet reliability criteria. This requirement increases to 520 MW (1% LIL bipole EqFOR) to 770 MW (10% LIL bipole EqFOR) by 2034. The NPV costs of the scenarios with a LIL bipole EqFOR of 5% and 10% compared to the scenario with a LIL bipole EqFOR of 1% are 1.3 and 1.5 times higher, respectively.

In all scenarios, with the exception of Scenario 4AEF (Minimum Investment Required), a minimum of approximately 335 MW of additional capacity resources are required by 2031 following the retirement of the Holyrood TGS, Hardwoods GT, and Stephenville GT. However, Scenario 4AEF (Minimum Investment Required) capacity requirement grows to approximately 385 MW by 2034, only three years later.

For the remainder of the Expansion Plan analysis, select Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required) Expansion Plans were advanced for further testing.

7.0 Further Testing of the Expansion Plans

In addition to running the PLEXOS model to determine the least-cost resource plan to meet Hydro’s probabilistic planning and firm energy criteria, there are other important factors to consider before advancing to the final recommended Expansion Plan. These considerations include:

- **The *CER*:** Hydro aims to align itself with ECCC, the *CER*, and the goal for a net zero GHG emissions economy by 2050. Where possible, Hydro intends to minimize its environmental footprint by using less fossil fuel generation to meet demand while maintaining a reliable system at a reasonable cost.

- **The LIL Shortfall Analysis:** A shortfall analysis (which explores the ability to meet load during a six-week LIL outage during the winter) was completed for select Scenario 4 (Minimum Investment Required) Expansion Plans combined with load forecast scenarios.
- **The On-Avalon Transmission Constraint:** Transmission analysis was completed to assess the performance of select Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required) Expansion Plans, specifically related to the transmission constraint from Off-Avalon to the load center On-Avalon during a LIL bipole outage.
- **Expansion Plan Iteration:** Select Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required) Expansion Plans, including the On-Avalon transmission upgrade requirements, were modelled in Hydro's Long-Term Financial Model to determine the impact of the required investment on customer rates. The new rates were then run through the load forecast model to determine the impact rate changes could have on the long-term load forecast. To determine if the demand and energy decreases were material enough to defer the timing of the required investment, the Expansion Plans were run again with the updated load forecast.

Each of these analyses is described further in the following sections.

7.1 The Expansion Plan and *CER*

Hydro aims to align itself with ECCC, the CER, and the goal for a net-zero GHG emissions economy by 2050. In August 2023, the Government of Canada released the first version of their draft *CER*,[132] and the February 2024 Public Update.[133] Although they are not finalized and remain subject to change, the draft *CER* are a key consideration in Hydro's evaluation of potential new sources of generation and subsequent Expansion Plans. Hydro's goal of minimizing its environmental footprint by using less fossil fuel generation must be balanced with the goal of maintaining a reliable system at a reasonable cost.

---

132 "Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations," Government of Canada, August 19, 2023. https://www.gazette.gc.ca/rp-pr/p1/2023/2023-08-19/html/reg1-eng.html

133 "Clean Electricity Regulations Public Update: 'What We Heard' during consultations and directions being considered for the final regulations," Environment and Climate Change Canada, February 16, 2024. https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/clean-fuel/electricity/clean-electricity-regulations-public-update-16022024.pdf

The draft *CER* are proposed to take effect in 2035, so that the electricity sector is on a path towards net-zero by 2050. The draft *CER* would apply to generating units meeting the following three criteria:

1) Uses any amount of fossil fuels to generate electricity;

2) Has a capacity of 25 MW or greater; and

3) Is connected to an electricity system that is subject to NERC standards.[134]

Based on the above criteria, the following existing Hydro generating stations would be subject to these regulations: the Holyrood TGS, the Stephenville GT, the Hardwoods GT, the Holyrood CT, and the Happy Valley-Goose Bay GT.

Hydro expects to have retired the Holyrood TGS, the Hardwoods GT, and the Stephenville GT prior to the time the proposed *CER* comes into effect in 2035.[135] The Holyrood CT and the Happy Valley-Goose Bay GT are primarily operated as peaking facilities, only being run as a backup in high-demand periods. A new CT greater than 25 MW in capacity would be subject to the regulations if run on fossil fuels.

The draft *CER* recognizes that certain jurisdictions may be required to maintain fossil-fuel-utilizing facilities as part of their fleet for various reasons. The February 2024 Public Update proposed a modified emissions limit approach, with a unit-specific annual emissions limit, calculated as shown in Figure 5.

$$\underset{(t/year)}{\textit{Unit Emission limit}} = \underset{(\mathrm{t/GWh})}{\textit{Performance standard}} \times \underset{(\textit{capacity of unit})}{\textit{MW}} \times \underset{(\textit{total hours in a year})}{\textit{8760 hours}} \times \underset{(\textit{unit conversion})}{\left(\frac{1\ GW}{1000\ MW}\right)}$$

Figure 5: Annual Limit on Emissions Calculation[136]

Based on the performance standard of 30 t/GWh proposed in the draft *CER*, the Holyrood CT and the Happy Valley-Goose Bay GT have been well within the emissions limit in each of the past five years.

[134] While Hydro is currently not NERC compliant, it is implied that the *CER* will also apply to the Newfoundland and Labrador Interconnected System in consideration of the interconnection to the North American Grid via the LIL and the Maritime Link.
[135] Currently, the Holyrood TGS, Stephenville GT and Hardwoods GT are all assumed to retire by the end of the first quarter of 2030.
[136] "Clean Electricity Regulations Public Update: 'What We Heard' during consultations and directions being considered for the final regulations," Environment and Climate Change Canada, February 16, 2024, sec. 1, p. 7. https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/clean-fuel/electricity/clean-electricity-regulations-public-update-16022024.pdf

However, as load grows on the Island Interconnected System, it is reasonable to expect that the Holyrood CT may operate more than it has historically. The emissions limit for a new 150 MW CT would equate to 39.4 kt of CO_2e per year. Based on the characteristics of the fuels currently used for generating electricity on the Island and the assumed heat rate (efficiency) of the LM6000 CT, this corresponds to approximately 60 GWh[137] of generation, or 390 hours (16 full days) of annual generation at maximum capacity (i.e., a 4.5% capacity factor). Should Hydro convert the new CT to burn renewable fuel (i.e., less carbon-intensive fuel resulting in decreased emissions) in the future, the unit would have increased flexibility to generate more.

In the February 2024 Public Update to the draft *CER*, ECCC indicated that a relaxation to this performance standard was under consideration, which would mean that a new 150 MW CT could exceed this generation amount and maintain compliance with the regulation while burning diesel as its fuel source. Based on the expected operation of a new CT as a peaking unit, providing backup generation in the event of high demand periods and/or contingency events, Hydro anticipates the operation of such units would be compliant with the proposed *CER*.

The February 2024 Public Update also indicated that a pooling framework is being contemplated to allow utilities owning multiple units to combine the emissions limits of individual existing units into a pooled emissions limit. This would enable the utility to operate its more efficient units ahead of less efficient units, ultimately leading to lower emissions and costs. Another provision being contemplated is to enable a unit to operate over its annual emissions limit by a limited amount provided it remits eligible offsets for the excess emissions. It is also proposed that in the event of an emergency,[138] emissions would not be counted towards a unit's annual emissions limit. All of these components would give Hydro additional flexibility to use thermal generating assets to maintain a reliable system while maintaining compliance with the draft *CER*.

Hydro continues to provide feedback to the federal government on its jurisdictional requirements and is monitoring the progress of these draft *CER*, as well as all other provincial and federal energy policy

[137] Based on a heat rate of 9,167 GJ/GWh, 38.5 MJ/L energy content of diesel fuel, and 2,800 g CO_2e/L.
[138] Hydro is working with ECCC to determine if the loss of the LIL bipole constitutes an emergency event based on the definition currently within the *CER*.

developments. With the information that is known today, Hydro is confident that it will be able to comply with the draft CER, even with the addition of one or more 150 MW peaking CTs.

7.2 The Expansion Plan and the LIL Shortfall Analysis

While the Expansion Plan analysis meets the firm energy criteria and the probabilistic planning criteria, the analysis is limited when considering the reliability of the Island Interconnected System, which faces most of its supply shortage risk during the winter period should a prolonged loss of the LIL bipole occur. As seen in the Planning Reserve Margin results identified in Table 4, Section 6.1, the Island Interconnected System reserve margin and the associated capacity requirements are highly dependent on the reliability of the LIL. Even if the LIL consistently has a LIL bipole EqFOR towards the bottom end of the analyzed range (1%), there is still the risk of an extended LIL bipole outage due to line icing or other failure modes. As a result, it is important to deterministically assess an extended outage of the LIL and the associated risk of supply shortfall events.

The extended outage scenario assumes the LIL is unavailable for six weeks[139] during the coldest period of the year (i.e., January and February). The LIL extended outage is intended to simulate an icing situation that causes a tower collapse in a remote segment of the transmission line; however, the extended outage scenario could generally apply to any prolonged outage event. There is a risk that such an outage could have a duration lasting longer than six weeks.

The analysis was completed on a probabilistic basis[140] and results are presented as 50th and 90th percentiles representing average and severe scenarios. The amount of shortfall is defined as the amount of load shedding required to restore to a minimum regulating reserve of 70 MW, as discussed in Section 5.1.5 of Appendix B. The average and severe shortfall cases are described as follows:

- **Average Case (50th Percentile):** Represents a generation shortfall that reflects a combination of average probabilistic outcomes, such as typical weather and unit availability, that would be expected to be exceeded 50% of the time in the analysis.

[139] Hydro used the output of the assessments completed by Haldar in combination with the information provided in the Emergency Response and Restoration Plan as the basis for considering the potential length of a significant outage of the LIL. Please refer to "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, sec. 5.2.
[140] The probabilistic analysis considers 2,400 random combinations of weather-driven loads, unit outage profiles, and renewable generation

- **Severe Case (90th Percentile):** Represents a generation shortfall that reflects a combination of severe probabilistic outcomes, such as severe weather and poor unit availability, that would be expected to be exceeded 10% of the time in the analysis.

This analysis does not consider transmission constraints but generation (supply) constraints only. Further discussion on transmission constraints during a LIL bipole outage is provided in Section 7.3.

The shortfall analysis was completed for the following combinations of Island load forecasts and Expansion Plans:

- **Combination 1:** Slow Decarbonization load forecast and no Expansion Resources;
- **Combination 2:** Slow Decarbonization load forecast and Scenario 4AEF (Minimum Investment Required) Expansion Plan;
- **Combination 3:** Slow Decarbonization load forecast and Scenario 4AEF (Minimum Investment Required) Expansion Plan with the second capacity resource advanced from 2034 to 2031 (referred to as Scenario 4 AEF(ADV) (Minimum Investment Required) going forward); and
- **Combination 4:** Reference Case load forecast and Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan.

Three charts, showing both Average and Severe Cases (as defined above), are presented for each of the above noted Combinations. The three charts illustrate the following:

1) Hourly generation shortfall in MW over the full six-week LIL outage in the 2032 winter period;

2) Hourly generation shortfall in MW over the peak day of the 2032 winter period; and

3) Duration curves showing the shortfall amount (in MW) for every hour over the six-week period. The data is ordered from highest to lowest and the probability of exceedance is calculated based on the rank of every hour. The approximate number of hours corresponding to each vertical gridline is shown at the top of each plot.

This analysis was completed using the 2032 reference year. As load continues to grow beyond 2032, it can be assumed that the level of shortfall would increase compared to what is depicted in this analysis, unless additional resources are added to the Island Interconnected System.

7.2.1 Combination 1

Combination 1 assumes Slow Decarbonization with no expansion resources, and, like all combinations described herein, assumes the retirement of the Holyrood TGS, Hardwoods GT, and Stephenville GT in 2030 (i.e., they are assumed retired prior to 2032). This combination provides a worst-case scenario and is meant to highlight that varying degrees of supply shortfall could be expected if a six-week LIL bipole outage were to occur and no new generation resources were added to the system. As Chart 17 demonstrates, under the Average Case (green line), the supply shortfall could be expected for the majority of the six-week period. An average of 682 hours of unserved energy would be expected (68% of the time), totalling 109 GWh of energy shortfall. The supply shortfall would occur primarily during peak hours, with the highest anticipated shortfall estimated to be 494 MW. Under the Severe Case (blue line), the peak shortfall is estimated to be 590 MW with 813 hours of unserved energy over the period (81% of the time), totalling 179 GWh of energy shortfall. Hydro does not expect this scenario to occur; it is presented for information and comparison purposes only.

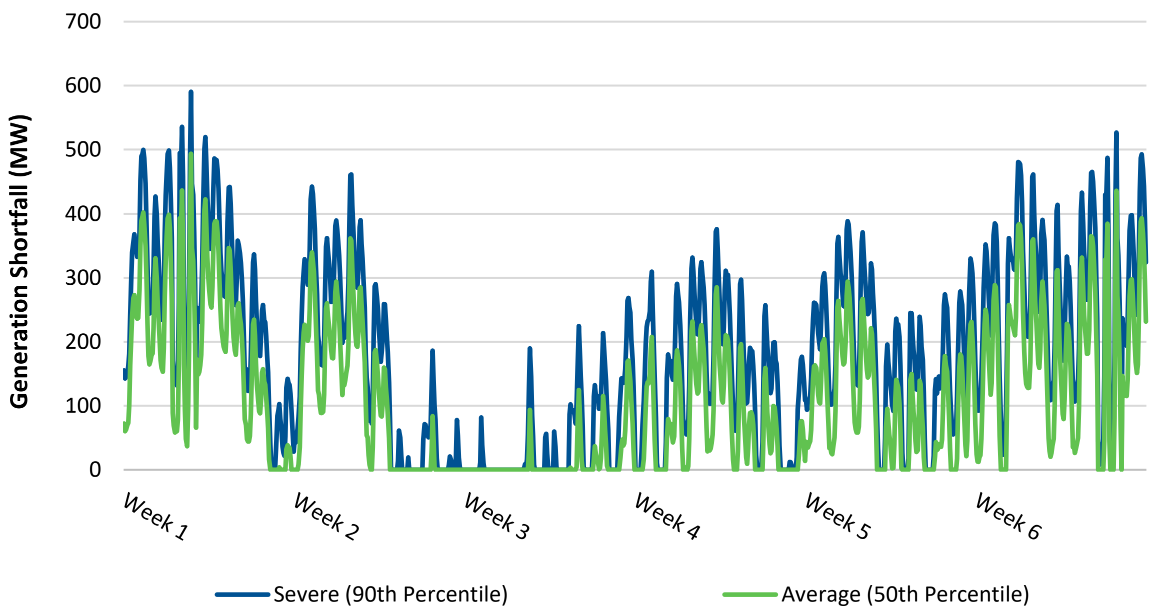


Chart 17: Shortfall over Six Weeks (Combination 1: Slow Decarbonization Load, No Expansion)

Chart 18 shows the estimated unserved energy on the peak day in the 2032 reference year.

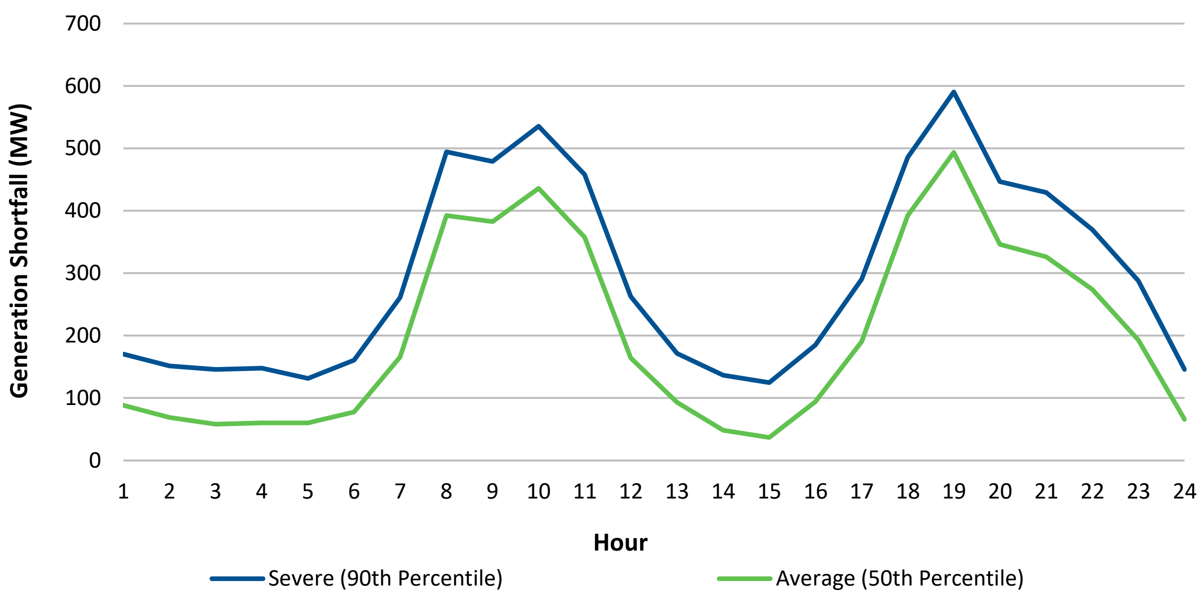


Chart 18: Shortfall on Peak Day (Combination 1: Slow Decarbonization Load, No Expansion)

1 Chart 19 depicts the shortfall duration curve for Combination 1 (Slow Decarbonization Load, No
2 Expansion). In the Average Case, a supply shortfall of 100 MW[141] or higher is expected approximately
3 45% of the time. In the Severe Case, a supply shortfall of 100 MW or higher is predicted approximately
4 66% of the time.

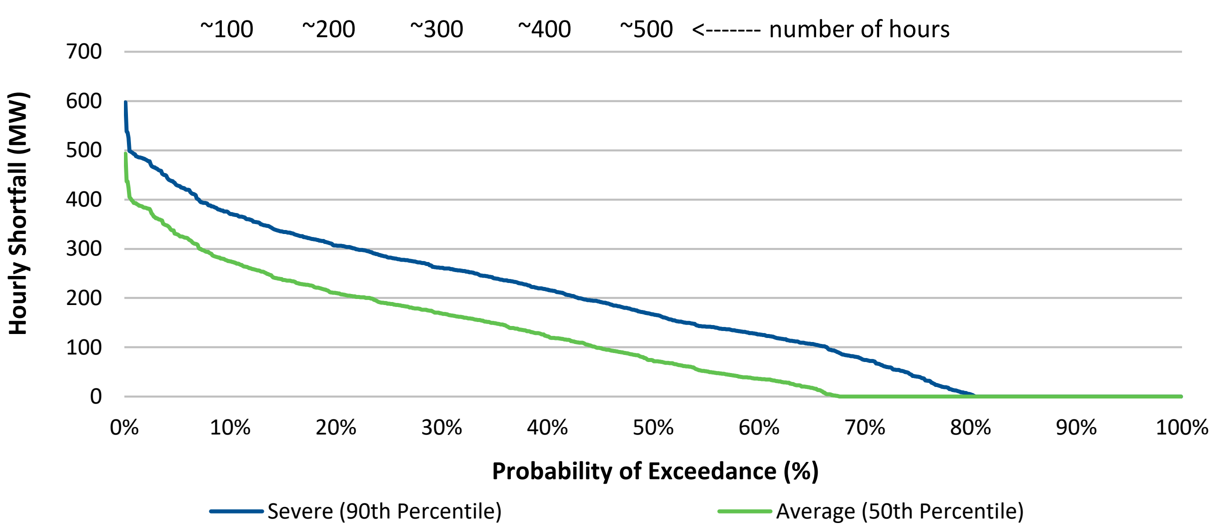


Chart 19: Shortfall Duration Curve (Combination 1: Slow Decarbonization Load, No Expansion)

141 Newfoundland Power was able to rotate 100 MW during the 2014 loss of load event.

7.2.2 Combination 2

Combination 2 assumes Slow Decarbonization with the Scenario 4AEF (Minimum Investment Required) Expansion Plan that considers a fixed wind profile, no batteries, and limits CTs to approximately 150 MW. As Chart 20 demonstrates, under the Average Case (green line), unserved energy would be expected to occur for 105 hours (10% of the time), totalling 6 GWh of energy shortfall. The supply shortfall would occur primarily during peak hours, with the highest anticipated shortfall estimated to be 216 MW. Under the Severe Case (blue line), the peak shortfall is estimated to be 323 MW with 321 hours of unserved energy over the period (32% of the time), totalling 28 GWh of energy shortfall.

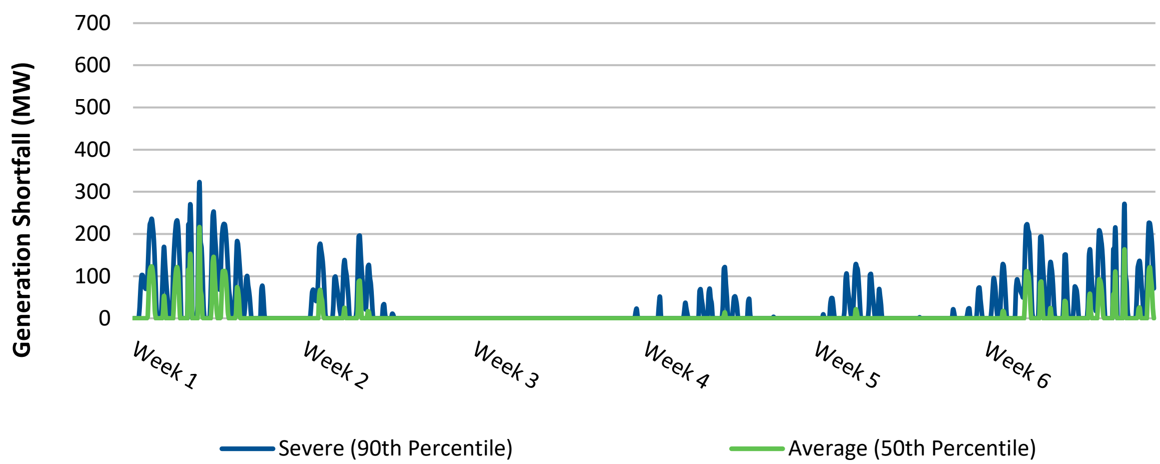


Chart 20: Shortfall over Six Weeks (Combination 2: Slow Decarbonization Load, Scenario 4AEF Minimum Investment Required) Expansion Plan)

Chart 21 shows the estimated unserved energy on the peak day in the 2032 reference year.

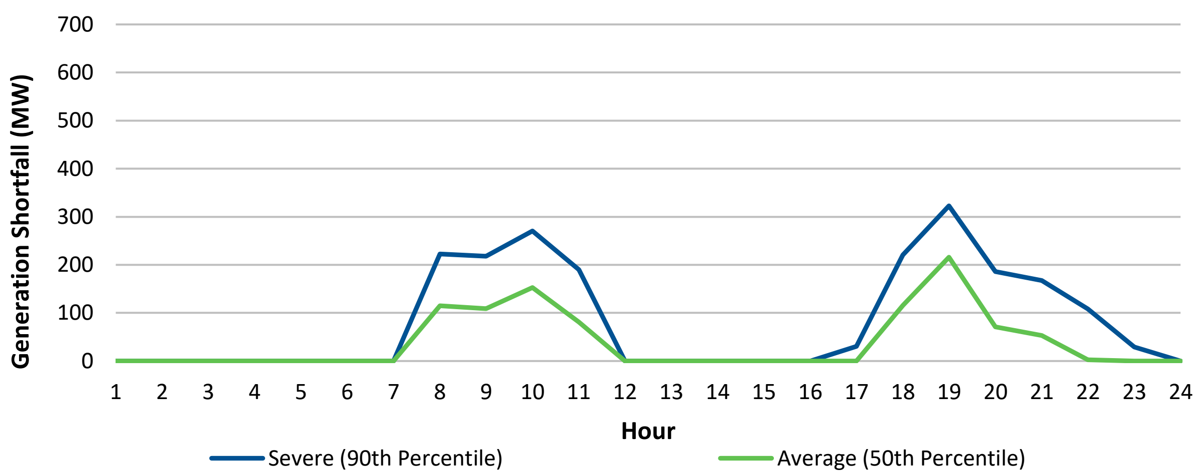


Chart 21: Shortfall on Peak Day (Combination 2: Slow Decarbonization Load, Scenario 4AEF (Minimum Investment Required) Expansion Plan)

Chart 22 depicts the shortfall duration curve for Combination 2 (Slow Decarbonization Load, Scenario 4AEF (Minimum Investment Required) Expansion Plan). In the Average Case, a supply shortfall of 100 MW[142] or higher is expected approximately 3% of the time. In the Severe Case, a supply shortfall of 100 MW or higher is expected approximately 12% of the time.

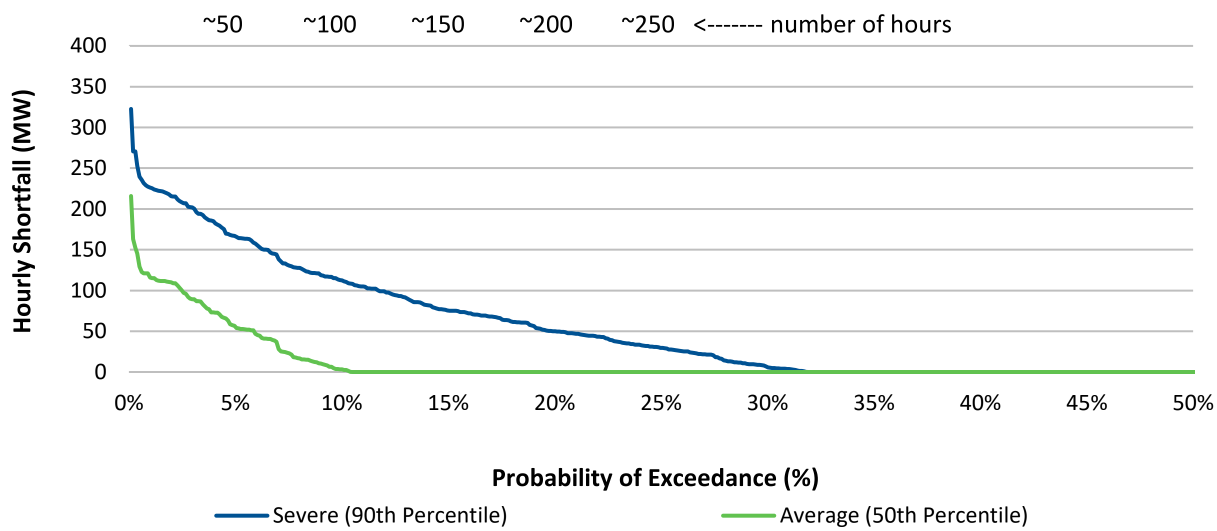


Chart 22: Shortfall Duration Curve (Combination 2: Slow Decarbonization Load, Scenario 4AEF (Minimum Investment Required) Expansion Plan)

7.2.3 Combination 3

Combination 3 assumes Slow Decarbonization with Scenario 4AEF (Minimum Investment Required) Expansion Plan with the second capacity resource advanced to 2031 (i.e. Scenario 4AEF (ADV)). This combination provides an assessment of the reduction of supply shortfall that could be expected by advancing the CT resource option by a few years. As Chart 23 demonstrates, under the Average Case (green line), unserved energy would be expected to occur for only 4 hours within the six-week period, representing approximately 0.1 GWh of energy shortfall. The highest anticipated generation shortfall is estimated to be 85 MW. Under the Severe Case (blue line), the peak shortfall is estimated to be 194 MW with 79 hours of unserved energy over the period, totalling 5 GWh of energy shortfall. Comparing Combination 3 to Combination 2 to isolate the effect of advancing the installation of the second capacity resource, the peak shortfall is reduced by approximately 130 MW in the Average Case (green line), with the hours of unserved energy reduced from 105 to 4. For the Severe Case (blue line), the peak shortfall

[142] Newfoundland Power was able to rotate 100 MW during the 2014 loss of load event.

is also reduced by approximately 130 MW, and the hours of unserved energy over the six-week period reduced from 321 hours to 79 hours. Advancing the second capacity resource from 2034 to 2031 has a material benefit to the reliability of the Island Interconnected System in the event of a prolonged LIL bipole outage.

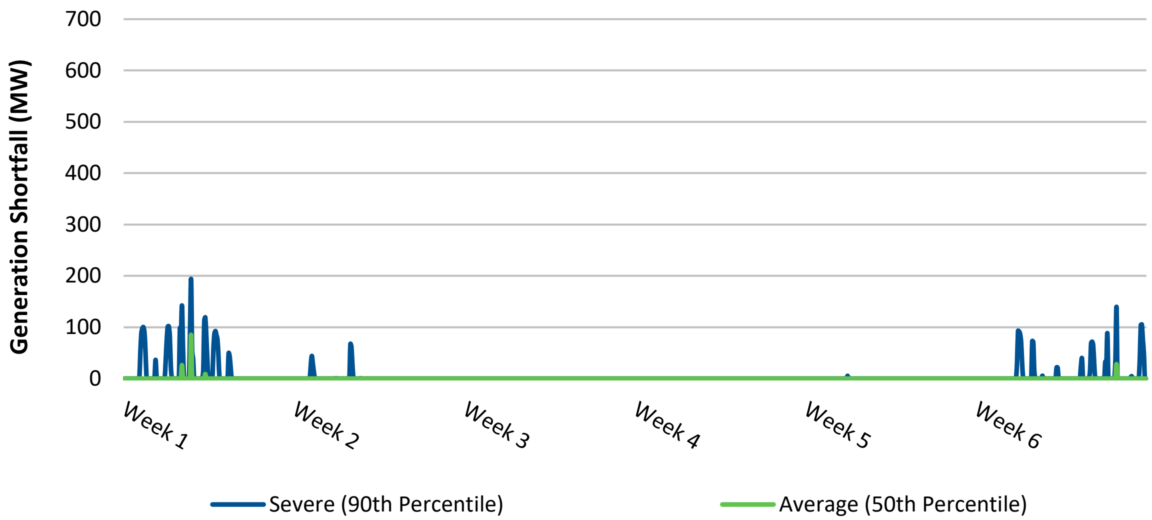


Chart 23: Shortfall over Six Weeks (Combination 3: Slow Decarbonization Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)

Chart 24 shows the estimated unserved energy on the peak day in the 2032 reference year.

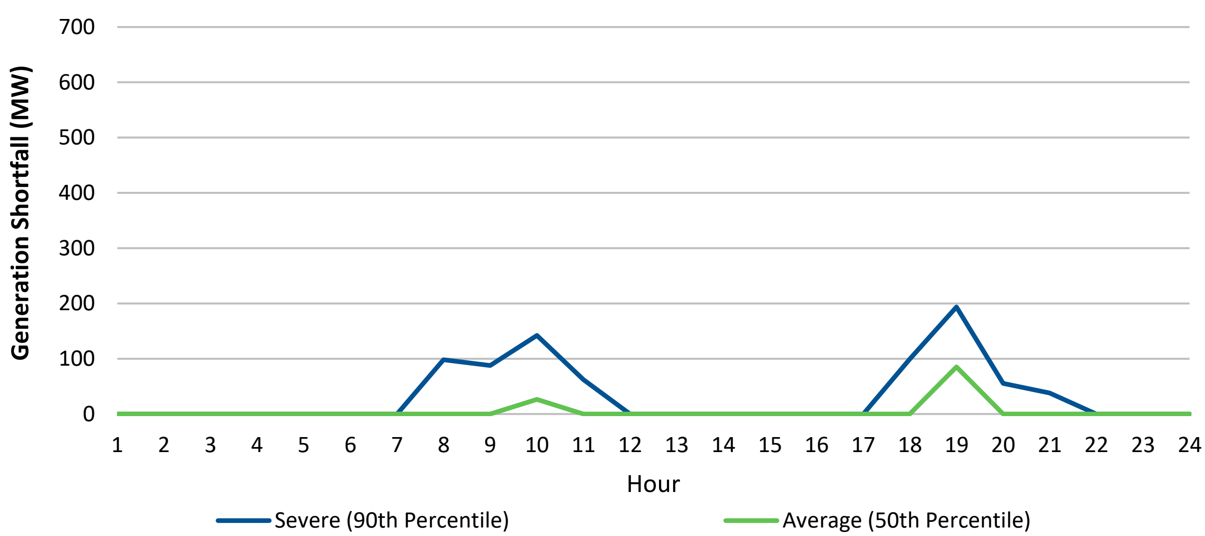


Chart 24: Shortfall on Peak Day (Combination 3: Slow Decarbonization Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)

Chart 25 depicts the shortfall duration curve for Combination 3 (Slow Decarbonization, Scenario 4AEF (ADV) (Minimum Investment Required) Expansion Plan). In the Average Case (green line), a supply shortfall of 100 MW[143] or greater is never experienced—the maximum shortfall is approximately 85 MW. In the Severe Case (blue line), a supply shortfall of 100 MW or higher is expected approximately 1% of the time.

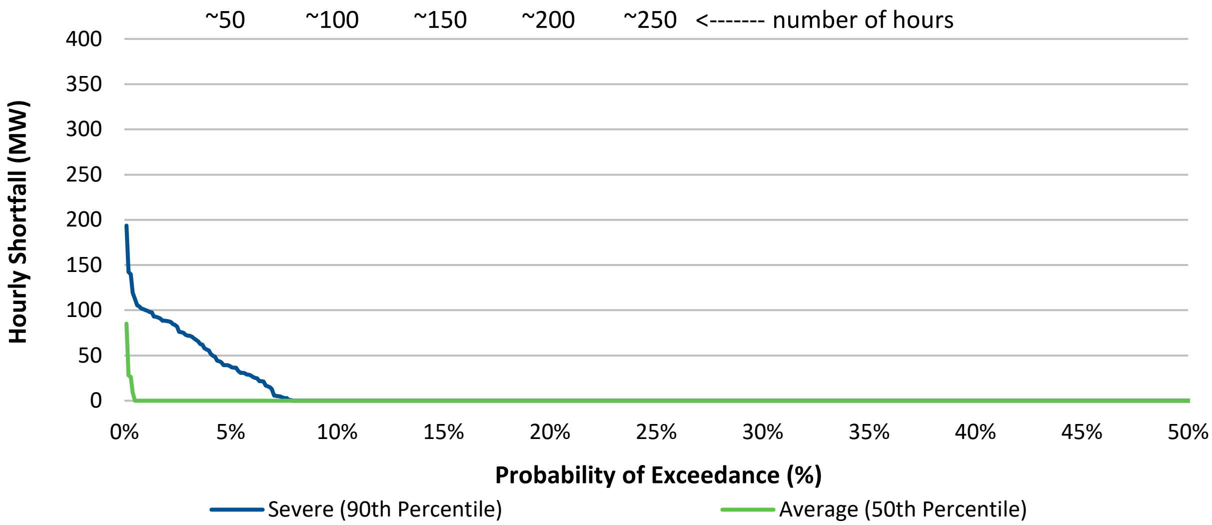


Chart 25: Shortfall Duration Curve (Combination 3: Slow Decarbonization Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)

7.2.4 Combination 4

Combination 4 assumes the Reference Case with Scenario 4AEF (Minimum Investment Required) Expansion Plan with the second capacity resource advanced to 2031 (i.e., Scenario 4AEF (ADV)). This combination provides an assessment of the supply shortfall that could be expected if the CT resource option was advanced by a few years and the Reference Case materialized. As Chart 26 demonstrates, under the Average Case (green line), unserved energy would be expected to occur in 33 hours over the six-week period, representing 1 GWh of energy shortfall. The highest anticipated shortfall is estimated to be 131 MW. Under the Severe Case (blue line), the peak shortfall is estimated to be 247 MW with 142 hours of unserved energy over the period, representing 10 GWh of energy shortfall.

[143] Newfoundland Power was able to rotate 100 MW during the 2014 loss of load event.

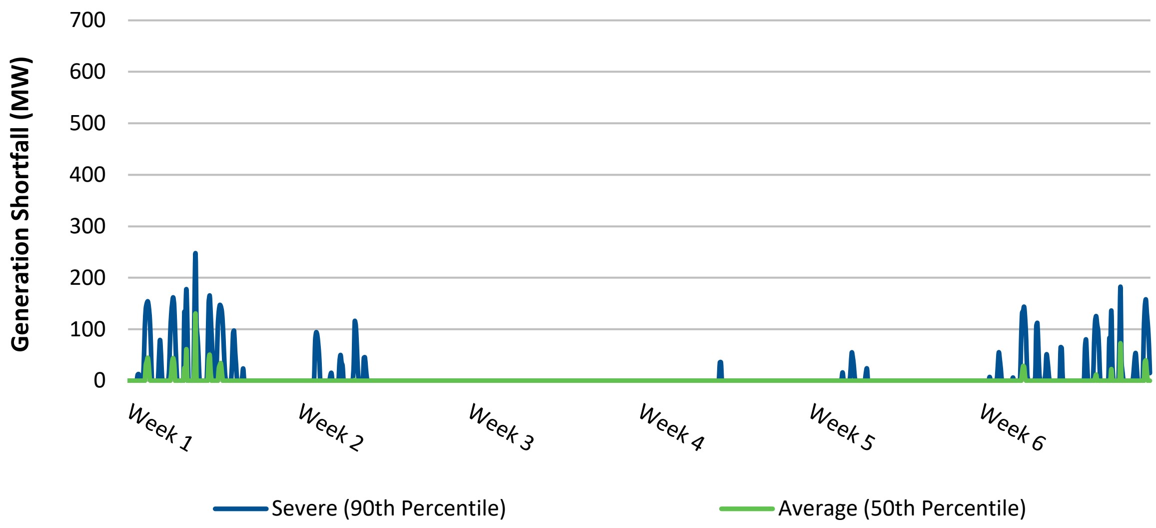


Chart 26: Shortfall over Six Weeks (Combination 4: Reference Case Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)

Chart 27 shows the estimated unserved energy on the peak day in the 2032 reference year.

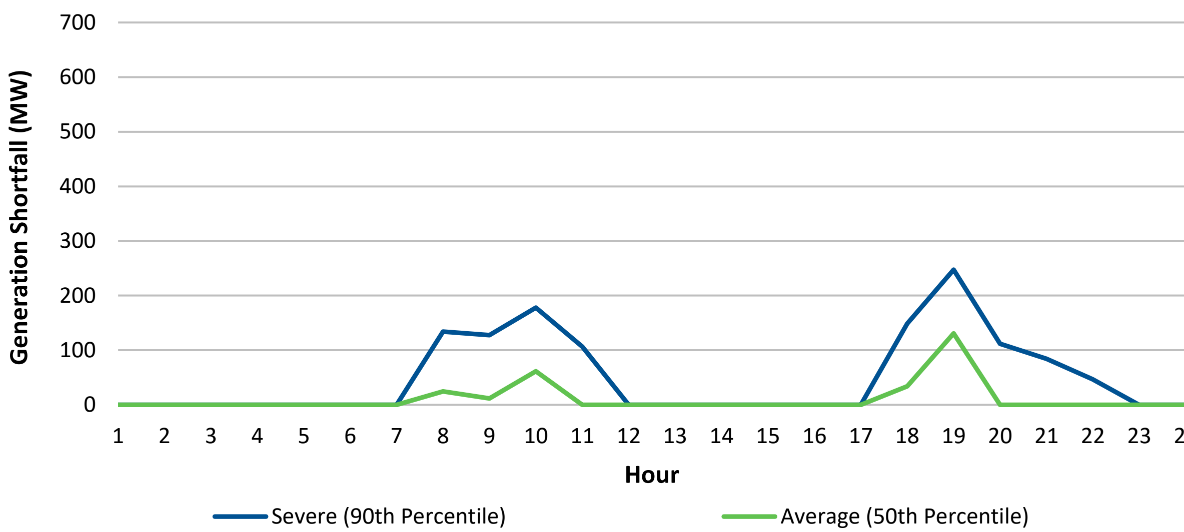


Chart 27: Shortfall on Peak Day (Combination 4: Reference Case Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)

Chart 28 depicts the shortfall duration curve for Combination 4 (Reference Load, Scenario 4AEF (ADV) (Minimum Investment Required) Expansion Plan). In the Average Case (green line), a supply shortfall of over 100 MW[144] occurs in only one hour over the six-week period. In the Severe Case (blue line), a supply shortfall of 100 MW or higher is expected approximately 4% of the time.

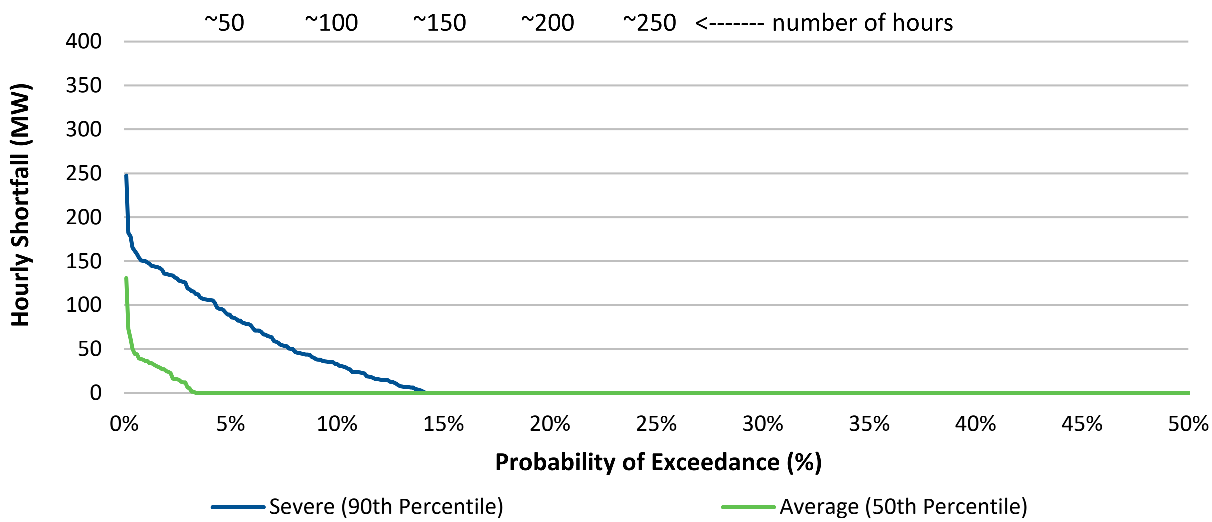


Chart 28: Shortfall Duration Curve (Combination 4: Reference Case Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)

7.2.5 Impact of Extended LIL Outage on Island Reservoir Storage

In early 2024, Hydro engaged Hatch to assess the impact of an unexpected six-week outage on the LIL to determine the effects on the Island reservoir levels as a complement to the generation shortfall analysis presented in Section 7.2. The analysis considered the impacts of a six-week LIL outage from the beginning of January to mid-February to align with the generation shortfall analysis. In addition, a six-week LIL outage from the beginning of March to mid-April was considered, as Island reservoir levels are typically low at this time of year, prior to the start of spring freshet. The analysis was conducted with the existing Island Interconnected System generation and a future system in 2032, which aligns with the recommended Expansion Plan presented in Section 8.0. The analysis was completed using the Vista model; simulations were performed using historic inflows from Hydro's reservoirs from 1958 to 2023.

Overall, the results from the outage simulations indicate that the system has adequate reservoir storage to make up for the loss of LIL imports to the Island by increasing hydro and thermal generation until the start of spring freshet in both years (2025 and 2032) that were analyzed; however, the start of spring freshet can vary. In January, the system is early in the winter drawdown and the results suggest a

[144] Newfoundland Power was able to rotate 100 MW during the 2014 loss of load event.

stronger thermal response is prudent to support reservoir levels to avoid the potential for critically low reservoir levels before the start of freshet. Conversely, higher hydro response is evident during the March outage simulation, as the system is close to the start of freshet and the risk for low reservoir levels reduces, allowing for increased hydro generation and less thermal response required. Once Hydro's aging thermal assets are retired from the system, the thermal response in January is naturally less, as the Holyrood TGS is no longer available to inject energy into the system.

The greatest impact of unexpected extended LIL outages is on reservoir levels in the Long Pond, Cat Arm, and Hinds Lake Reservoirs in both 2025 and 2032. Bay d'Espoir is Hydro's largest facility on the Island, which is supplied by the Long Pond Reservoir. As such, maintaining appropriate reservoir levels at Long Pond in advance of winter is of particular importance, to ensure continued rated output of the facility. By the end of the winter period in 2025, the Long Pond Reservoir was drawn down to approximately 70 cm above the low supply level[145] in many of the hydraulic sequences, which includes support from thermal resources. With the addition of Bay d'Espoir Unit 8, the 2032 simulations indicate that more hydraulic sequences approach but do not exceed the low supply level. During this time, it is assumed that standby generation will be online to support demand requirements. As expected, this analysis indicates that Long Pond storage levels would likely be a concern during a prolonged LIL outage during the periods studied in this analysis (2025 and 2032).

Bypassing of Upper Salmon was not needed in any of the simulations that were ran; however, should additional inflows be required to support Long Pond storage to maintain rated output of Bay d'Espoir, bypass of Upper Salmon can occur. Hydro continuously monitors the storage of its reservoirs to ensure continued rated output of the hydroelectric facilities through the winter period. The full study can be found in Attachment 5 to this Appendix.

As the Island Interconnected System's future needs evolve, resources are retired, and new resources are added, this analysis will be modified accordingly.

[145] The low supply level is the level at which rated flow can be maintained.

7.3 The Expansion Plan and On-Avalon Transmission Constraints

Hydro engaged TransGrid to complete a study[146] to determine the Bay d'Espoir to Soldiers Pond transmission constraints during a LIL bipole outage.[147] The TransGrid Study also presented a series of potential capital transmission upgrade options that could alleviate these constraints to facilitate more new Off-Avalon generation. A simplified diagram of the Bay d'Espoir to Soldiers Pond 230 kV transmission system is provided in Figure 6, which includes reference to terminal stations in Sunnyside, Come By Chance, Western Avalon, and Long Harbour.

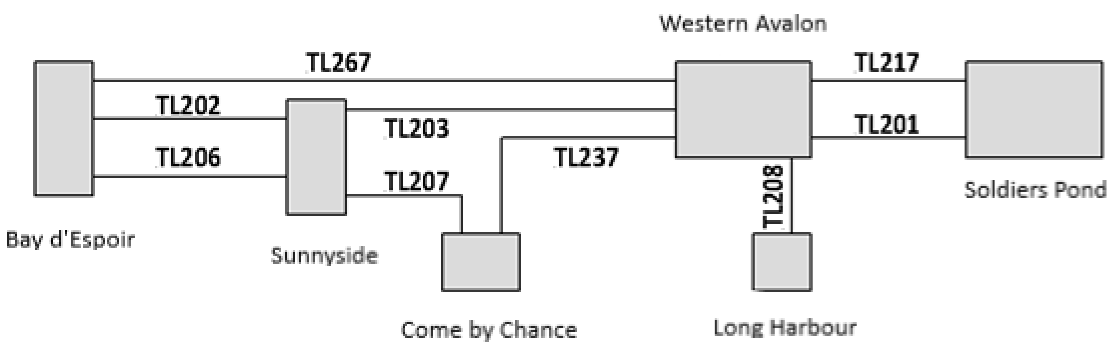


Figure 6: Bay d'Espoir to Soldiers Pond 230 kV Transmission System

Following the transition from generation to SC operations at the Holyrood TGS and the Hardwoods GT, the Bay d'Espoir to Soldiers Pond transmission system must supply the majority of the Avalon's demand during a LIL bipole outage, assuming no new generation sources are constructed on the Avalon. The existing Bay d'Espoir to Soldiers Pond transmission constraints are defined based on 230 kV line contingencies that cause thermal overloads on lines remaining in service and/or low voltage conditions that must be avoided to ensure reliable and safe operation.[148]

Understanding the limitations of the Bay d'Espoir to Soldiers Pond transmission system is an important component of the analysis required in support of a generation Expansion Plan. The addition of new generation sources will impact the flow of electricity in the transmission network. For example, more

[146] "Avalon Supply (Transmission) Study – Overview," Newfoundland and Labrador Hydro, October 31, 2023.
[147] The transmission transfer capability west of Bay d'Espoir is less of a factor for the *RRA Study Review*, given the majority of the Island load is east of Bay d'Espoir and the long-term plan is to remove large generation sources on the Avalon.
[148] For example, the sudden loss of TL217 during a LIL bipole outage when Avalon load is greater than 664 MW, which equates to an Island demand of 1,285 MW, will result in a thermal overload of TL201. A thermal overload occurs when power flow through a line exceeds its rated capacity. Rated capacity is a function of various environmental factors including ambient temperature.

generation on the Avalon would reduce power flow on the Bay d'Espoir to Soldiers Pond transmission system. This is of particular importance in the event of a LIL bipole outage.

The TransGrid Study had two main objectives that were divided into two phases:[149]

- **Phase 1**: Determine all the existing 230 kV transmission constraints between Bay d'Espoir and Soldiers Pond with current Avalon thermal generation sources unavailable.[150] The analysis involved assessing various 230 kV line contingencies between Bay d'Espoir and Soldiers Pond to determine transfer limits with and without the LIL online.
- **Phase 2**: Determine the increased transfer capacity to the Avalon for various transmission reinforcement options provided by Hydro. This analysis involved assessing various 230 kV line contingencies between Bay d'Espoir and Soldiers Pond for each option.

The TransGrid Study is not intended to and does not make recommendations as to whether transmission reinforcements should be proposed. Rather, the TransGrid Study provides valuable information that will serve as input to, and improve the quality of, Hydro's resource planning model. It is a prudent, necessary step to consider the Bay d'Espoir to Soldiers Pond transmission constraints, as the solution to mitigate these constraints to enable particular generation expansion scenarios could come with a considerable cost and must be factored into the larger system supply decisions. A study of the options to mitigate these transmission constraints may also identify short-term options to alleviate supply constraints and provide reliability or financial benefits in advance of generation expansion.

7.3.1 Summary of TransGrid Study Results

7.3.1.1 Phase 1

The primary objective of Phase 1 of the TransGrid Study was to determine all the 230 kV transmission "bottlenecks" between Bay d'Espoir and Soldiers Pond during a LIL bipole outage. As shown in Table 40, (highlighted green) the most limiting (N-1) contingency is the loss of TL217, which overloads TL201. As noted herein, an outage to TL217 during a LIL bipole outage would result in a customer impact when Avalon gross load exceeds 664 MW, which corresponds to Island demand of 1,285 MW.

[149] A third phase has commenced to evaluate the feasibility of an RAS to potentially reduce the scope of capital upgrades evaluated as part of Phase 2.
[150] The Hardwoods GT and Unit 3 at the Holyrood TGS will continue to operate solely as SCs.

Table 40: LIL Bipole Outage – Transmission Bottlenecks (Bay d'Espoir to Soldiers Pond)

Contingency	Power Transfer Limit (East) out of BDE (MW)	Corresponding Island Demand that can be Served (MW)[151]	Avalon Gross Load[152] that can be Served (MW)	Limiting Criteria
System Intact	980	1865	964	Voltage Levels at SSD
System Intact	912	1771	918	Voltage Levels at SSD
Steady-State N-1 (TL237)	921	1770	921	Voltage Levels at WAV
Steady-State N-1 (TL203)	916	1765	918	Voltage Levels at WAV
Steady-State N-1 (TL207)	901	1745	909	Voltage Levels at SSD
Steady-State N-1 (TL201 or TL217)	872	1700	885	Voltage Levels at SSD
Steady-State N-1 (TL203)	836	1630	853	Thermal Overload (TL207)
Steady-State N-1 (TL206 or TL202)	805	1595	832	Voltage Levels at SSD
Steady-State N-1 (TL201)	780	1550	810	Thermal Overload TL217
Steady-State N-1 (TL267)	773	1545	807	Voltage Levels at SSD
Three-Phase Fault at WAV (TL267)	760	1525	794	System Instability
Steady-State N-1 (TL267)	683	1410	733	Thermal Overload (TL202/TL206/TL203)
Steady-State N-1 (TL237)	679	1400	730	Thermal Overload (TL203)
Steady-State N-1 (TL206 or TL202)	679	1400	730	Thermal Overload (TL202/TL206)
Steady-State N-1 (TL207)	659	1375	714	Thermal Overload (TL203)
Steady-State N-1 (TL217)	603	1285	664	Thermal Overload (TL201)

7.3.1.2 Phase 2

The primary objective of Phase 2 of the TransGrid Study was to perform a technical evaluation of various options for Bay d'Espoir to Soldiers Pond transmission upgrades to determine the opportunity for an incremental increase in power transfer capacity to the Avalon during a LIL bipole outage following the conversion of the Holyrood TGS and the Hardwoods GT to SC operation. This would have the potential benefit of minimizing customer impact in such a scenario.

The Bay d'Espoir to Soldiers Pond transmission upgrade options considered in the TransGrid Study include:[153]

- **Option 1**: Reconductor (TL201, TL203, TL202/TL206);

[151] Corresponding Island demand that can be served assumes today's Island and Avalon split ratio of approximately 52%.
[152] Avalon Gross Load is the total load of the Avalon including industrial customers. This would include any customers electrically downstream (east) of the Western Avalon TS as well as Vale.
[153] Evaluation of slight variations of the options listed may occur if they are deemed more appropriate for specific generation expansion scenarios being considered.

- **Option 2**: Option 1 + DLR (TL201/TL217, TL203, TL202/TL206);
- **Option 3**: Third line (Western Avalon to Soldiers Pond) + Reconductor (TL203/TL202/TL206);
- **Option 4**: Third line (Western Avalon to Soldiers Pond) + DLR (TL201, TL202, TL206, TL203);
- **Option 5**: Option 4 + Reconductor (TL203/TL202/TL206);
- **Option 7**: Option 5 + terminate TL267 at Black River;[154]
- **Option 8f**: Option 7 + a new 230 kV line from Bay d'Espoir to Black River (tap off of TL204/TL231);
- **Option 10**: A new 230 kV circuit from Bay d'Espoir to Soldiers Pond; and
- **Option 10a**: Option 10 + reactive power support[155] in the Sunnyside/Come by Chance area.

The analysis also assessed the impact of generation additions both on and off the Avalon, allowing for an understanding of the reliability impacts of transmission upgrades in various expansion scenarios. The results of this analysis are presented in Table 41. The forecasted peak demand for the Island Interconnected System is approximately 1,920 MW by 2034. It is important to note the benefit of having 150 MW of capacity located on the Avalon as it allows for a capacity increase to the Avalon and an increase in the total Island load that can be served.

[154] A potential new terminal station east of Sunnyside known as the Black River Terminal Station.
[155] The addition of reactive power would improve voltage levels following specific 230 kV contingencies, thereby increasing power transfer capabilities.

Table 41: Overall Comparison of Bay d'Espoir to Soldiers Pond Upgrade Options

Options	No New Avalon Generation					Additional 150 MW @ Holyrood TGS				
	No New Reactive Power		New Reactive Power Support in SSD/CBC Area[156]			No New Reactive Power		New Reactive Power Support in SSD/CBC Area[157]		
	Maximum IIS Demand (MW)	Capacity Increase to Avalon (MW)	Maximum IIS Demand (MW)	Capacity Increase to Avalon (MW)	Additional Reactive Requirement (MVAr)	Maximum IIS Demand (MW)	Capacity Increase to Avalon (MW)	Maximum IIS Demand (MW)	Capacity Increase to Avalon (MW)	Additional Reactive Requirement (MVAr)
1 to 5	1,560-1,680	130-200	1,750-1,815	200-275	200-225	1,835-1,880	285-325	1,945-2,025	360-415	100-125
7	1,675	205	1,864	245	300	1,938	350	2,060	415	225
8f	1,844	300	2,067	415	400	2,082	435	2,234	510	175
10	1,896	230	2,146	345	75	2,167	385	2,288	448	None
10a	2,096	300	*	*	*	2,293	420	*	*	*
* Not studied with additional reactive power since Island demand that can be met is already >= 2,100 MW										

The TransGrid Study has provided various Bay d'Espoir to Soldiers Pond transmission upgrades with incremental transfer limit increases that should address any generation expansion scenario considered by Hydro. Further, Hydro is exploring whether lower-cost steps can be taken to maximize transfer capacity through existing assets, including the implementation of an RAS[158] and/or DLR technology as a technically equivalent option to Option 4 transmission upgrades. An RAS would be designed to trigger protective relays following a contingency event to avoid a transmission line overload and/or abnormal voltage conditions. The thermal rating of a transmission line is typically calculated based on a series of conservative inputs to account for the worst-case weather conditions. Using real-time data, DLR technology would allow Hydro to be less conservative and operate a line to its true capacity based on the weather and conductor conditions at that moment in time. Hydro must evaluate these options to determine if they are technically viable (individually or combined) for the Bay d'Espoir to Soldiers Pond transmission system.

7.3.2 Expansion Plan Transmission Requirements

Since the TransGrid Study was completed, Hydro developed AACE Class 5 cost estimates for select options evaluated during Phase 2 of the TransGrid Study. With the development of the generation Expansion Plans, Hydro was able to determine the potential appropriate accompanying transmission expansion solutions to provide reliable service to customers and reduce the scope of future transmission

[156] New 4 x 38 MVAr capacitor bank + STATCOM.
[157] New 4 x 38 MVAr capacitor bank + STATCOM.
[158] In industry, RAS is sometimes referred to as Special Protection Scheme.

upgrades. This analysis is deterministic in nature and assumes that all existing and new generation is available and online with the exception of the LIL. Therefore, should additional generation outages or derations occur, the results could be worse than presented.

The transmission upgrade option, cost, and corresponding peak demand both on and off the Avalon that can be served during a LIL bipole outage are summarized in Table 42 through Table 44 for select scenarios. For all scenarios considered in this analysis, the results were compared for 2031 and 2034, to compare the impact of a LIL bipole outage on the transmission system after the planned retirement of the Holyrood TGS, Hardwoods GT, and Stephenville GT and again at the end of the study period to determine the increase in load shedding requirements due to load growth impacts on the system as load growth is forecasted to continue to increase.

7.3.2.1 No Bay d'Espoir to Soldiers Pond Transmission Upgrades Applied

Table 42 summarizes the amount of pre-emptive load shedding that would be required on and off the Avalon for each generation expansion scenario assuming none of the transmission upgrade options assessed in the TransGrid Study are executed. Variations between results for 2031 and 2034 are due to the changes in load and generation additions during this period, as specified for each scenario.

Table 42: Expansion Plans with no Transmission Upgrades (LIL Bipole Outage)

		1st Thermal Violation (No Upgrade)						
Scenario	Year	Peak Island Load[159] (MW)	Island Load That Can Be Served[160] (MW)	BDE Flow (East) (MW)	Gross Avalon Load That Can Be served (MW)	Avalon Load Shed[161] (MW)	Peak Gross Avalon Demand Served (%)	Peak Island Demand Served (%)
S1AEF	2031	1,967	1,666	680	857	157	85.4	92.0
	2034	2,051	1,762	691	912	150	85.9	92.7
S1AEI	2031	1,963	1,665	686	862	152	85.0	92.3
	2034	2,070	1,678	675	861	203	80.9	90.2
S4AEF	2031	1,948	1,395	635	707	289	71.0	85.2
	2034	1,971	1,667	686	863	160	84.4	91.9
S4AEF (ADV)	2031	1,902	1,668	686	864	123	87.5	93.5
	2034	1,971	1,667	686	863	160	84.4	91.9
S4AEI	2031	1,951	1,399	633	707	289	71.0	85.2
	2034	2,031	1,399	633	708	326	68.5	83.9

,

7.3.2.1.1 Scenario 1: Reference Case

Should Scenario 1AEF (Reference Case) Expansion Plan proceed as presented in Section 6.3 (with no transmission upgrades) and a LIL bipole outage were to occur, upwards of 85.4% of Avalon peak can be served in 2031, increasing slightly to 85.9% by 2034. Load shedding requirements east of Soldiers Pond, characterized in Table 42 as "Avalon Load Shed," are above 100 MW[162] during the study period. Should load continue to grow, the percent of peak served will continue to reduce and the required load shed amount will increase and deeper shortfalls will be experienced on the Island Interconnected System.

Similarly, should all additional generation be added off the Avalon with no additional generation added on the Avalon, as reflected in Scenario 1AEI (Reference Case), the amount of load shed is comparable to Scenario 1AEF (Reference Case) in 2031. However, the amount of load shed grows above 200 MW of Avalon load-shedding requirements by 2034. Therefore, approximately an additional 50 MW of load

[159] Includes transmission losses and station service loads after curtailment.
[160] Includes transmission losses and station service loads after curtailment.
[161] Avalon load will be shed following a LIL bipole trip due to UFLS. The amount of restored load would be the total amount shed following a LIL bipole trip minus the value in the "Avalon Load Shed" column.
[162] Newfoundland Power was able to rotate 100 MW during 2014 loss of load event.

shedding requirements on the Avalon could occur in this case, compared Scenario 1AEF (Reference Case) Expansion Plan. This supports the need for On-Avalon generation with synchronous SC capability.

7.3.2.1.2 Scenario 4: Minimum Investment Required

As the Scenario 4AEF (Minimum Investment Required) Expansion Plan has the least amount of generation added to the system to counteract the impacts of a LIL bipole outage. Should this scenario occur, only 71.0% of Avalon load can be served at peak in 2031, increasing to 84.4% in 2034 due to the addition of the CT in the same year. While the On-Avalon load rotation requirements reach approximately 290 MW in 2031, they reduce to approximately 160 MW by 2034, highlighting the benefit of the addition of the 142 MW CT on the Avalon in 2034 of the Expansion Plan, against the impact of a LIL bipole outage. Should the second capacity resource advance to 2031 at the same time as the first capacity resource, as identified in Scenario 4AEF(ADV) (Minimum Investment Required), the percent of peak served increases to 87.5% in 2031, reducing to 84.4% by 2034 as load grows.

Alternatively, should all additional generation be added off of the Avalon with no additional generation added on the Avalon, as is the case in Scenario 4AEI (Minimum Investment Required), the amount of load shed is similar to Scenario 4AEF (Minimum Investment Required) in 2031. However, Avalon load shedding requirements grow upwards to 326 MW by 2034. Therefore, approximately an additional 166 MW of load shedding on the Avalon could be required in this case, compared to any other Scenario 4 (Minimum Investment Required) Expansion Plan considered in this analysis. This reiterates the positive impact that On-Avalon generation has on the overall reliability of the Island Interconnected System.

7.3.2.2 Transmission Capacity Increase (Option 4)

Option 4 would include the construction of a third line (Western Avalon to Soldiers Pond) in addition to adding DLR on TL201, TL202, TL206, and TL203, with a total cost of approximately $150 million.[163] As mentioned previously, the implementation of an RAS and DLR technology, as technically equivalent to the Option 4 transmission upgrade, is currently being studied to determine technical feasibility and has the potential to be a lower-cost option. However, in the event of significant unexpected load growth and/or a change in the acceptable amount of customer impact during a LIL bipole outage, there could be a requirement for a more costly transmission solution beyond Option 4 ($150 million). Table 43

[163] All costs are presented in 2023 CDN.

summarizes the results of applying Option 4 (or equivalent) as the least-cost transmission solution for each scenario analyzed.

Table 43: Expansion Plans with Option 4 Applied (LIL Bipole Outage)

		Voltage Violation (Option 4 Applied)						
Scenario	**Year**	**Peak Island Load[164] (MW)**	**Island Load That Can Be Served[165] (MW)**	**BDE Flow (East) (MW)**	**Gross Avalon Load That Can Be Served (MW)**	**Avalon Load Shed[166] (MW)**	**Peak Gross Avalon Demand Served (%)**	**Peak Island Demand Served (%)**
S1AEF	2031	1,967	1,807	779	932	82	91.9	95.8
	2034	2,051	1,880	774	974	88	91.7	95.7
S1AEI	2031	1,963	1,808	780	935	79	92.2	96.0
	2034	2,070	1,817	773	935	129	87.9	93.8
S4AEF	2031	1,948	1,601	780	819	177	82.2	87.7
	2034	1,971	1,800	779	934	89	91.3	94.1
S4AEF(ADV)	2031	1,902	1,804	780	935	52	94.7	97.3
	2034	1,971	1,800	779	934	89	91.3	94.1
S4AEI[167]	2031	1,951	1,652	808	844	152	84.7	91.5
	2034	2,031	1,652	808	844	190	81.6	87.9

7.3.2.2.1 Scenario 1: Reference Case

Applying this transmission solution to the Scenario 1AEF (Reference Case) Expansion Plan results in approximately 91.9% of Avalon peak that can be met in 2031, reducing slightly to 91.7% in 2034, resulting in On-Avalon load shedding requirements of approximately 82 MW to 88 MW.

Alternatively, should all additional generation be added off of the Avalon with no generation on the Avalon, as reflected in Scenario 1AEI (Reference Case), the amount of required Avalon load shedding grows to approximately 130 MW by 2034. Therefore, an additional 40 MW of load shedding requirements on the Avalon could occur in this case when compared to Scenario 1AEF (Reference Case). Again, these results support the need for On-Avalon generation with SC capability.

[164] Includes transmission losses and station service loads after curtailment.
[165] Includes transmission losses and station service loads after curtailment.
[166] The load will not shed immediately after the loss of the LIL bipole but it will need to be shed pre-emptively in preparation for the next contingency.
[167] Option 4 applied is insufficient to maintain reliability. Reactive Power support is also required for this scenario.

7.3.2.2.2 Scenario 4: Minimum Investment Required

Applying the Option 4 transmission upgrade to the Scenario 4AEF (Minimum Investment Required) Expansion Plan materially improves the percent of peak that can be served compared to what was seen in Table 42. In 2031, approximately 82.2% of Avalon peak can be served, increasing to 91.3% of Avalon peak by 2034 when the CT is added to the Expansion Plan, at which point load rotation requirements on the Avalon reduce to approximately 90 MW. However, by advancing the CT build from 2034 to 2031 represented by Scenario 4AEF (ADV) (Minimum Investment Required), a material improvement in the percent of peak served occurs in 2031, resulting in almost a 13% improvement and a 125 MW reduction in On-Avalon load shedding. By 2034, the percent of Avalon demand served is the same as Scenario 4AEF (Minimum Investment Required), as both Expansion Plans include a CT located on the Avalon by the end of the study period.

Alternatively, should all additional generation be added off of the Avalon with no generation added on the Avalon, as reflected in Scenario 4AEI, the amount of load shed is similar to Scenario 4AEF (Minimum Investment Required) in 2031, as there is no additional On-Avalon generation in that year. However, the Avalon load-shedding requirement will grow to approximately 190 MW of by 2034. Therefore, approximately an additional 100 MW of load-shedding requirements on the Avalon could occur in this case compared to any other Scenario 4 (Minimum Investment Required) Expansion Plan. Additionally, the analysis indicates that Scenario 4AEI (Minimum Investment Required) would require additional transmission upgrades beyond applying Option 4, such as reactive power support in the Come by Chance/Sunnyside area by 2034.

7.3.2.3 Transmission Capacity Increase (Option 4 or Equivalent + Reactive Power Support)

In order to maximize the flow of generation along the Bay d'Espoir to Soldiers Pond corridor in the event of a LIL bipole outage, all generation was maximized and the resultant long-term transmission capital upgrades were determined. In all scenarios considered, Option 4 + reactive power support[168] in the Come by Chance/Sunnyside area were required, resulting in a total cost of approximately $350 million to $400 million.[169] As mentioned previously, the implementation of an RAS and DLR technology as technically equivalent options to the Option 4 transmission upgrade is being studied, which could

[168] Addition of capacitor banks and a STATCOM.
[169] All costs are presented in 2023 CDN.

reduce the current estimated cost of these upgrades. Table 44 summarizes the results of applying Option 4 in addition to reactive power support for each scenario analyzed.

Table 44: Expansion Plan with Option 4 + Reactive Power Support Applied (LIL Bipole Outage)

		Island Generation Maxed Out (Option 4 + Reactive Power Support)						
Scenario	Year	Peak Island Load[170] (MW)	Island Load That Can Be Served[171] (MW)	BDE Flow (East) (MW)	Gross Avalon Load That Can Be Served (MW)	Avalon Load Shed[172] (MW)	Peak Gross Avalon Demand Served (%)	Peak Island Demand Served (%)
S1AEF	2031	1,967	1,905	850	982	32	96.8	96.8
	2034	2,051	1,978	841	1025	37	96.7	96.4
S1AEI	2031	1,963	1,912	855	989	25	97.5	97.4
	2034	2,070	2,003	908	1031	33	96.9	96.8
S4AEF	2031	1,948	1,709	856	875	121	87.9	87.7
	2034	1,971	1,854	817	963	60	94.1	94.1
S4AEF(ADV)	2031	1,902	1,852	815	961	26	97.4	97.4
	2034	1,971	1,854	817	963	60	94.1	94.1
S4AEI	2031	1,951	1,786	907	914	82	91.8	91.5
	2034	2,031	1,786	907	914	120	88.4	87.9

7.3.2.3.1 Scenario 1: Reference Case

Unsurprisingly, the level of transmission upgrades to fully utilize all new Off-Avalon generation to help serve Avalon load during a LIL outage materially increases the load that can be served at peak and significantly diminishes, but does not eliminate, the load shedding requirements that will need to be rotated. For Scenario 1AEF (Reference Case) and Scenario 1AEI (Reference Case), up to 96.7% to 97.5% of Avalon load can be served during a LIL bipole outage should this level of investment occur.

7.3.2.3.2 Scenario 4: Minimum Investment Required

In the worst-case scenario (Scenario 4AEF (Minimum Investment Required) Expansion Plan), only 87.9% of the Avalon peak load can be served in 2031, resulting in approximately 120 MW of load shedding

[170] Includes transmission losses and station service loads after curtailment.
[171] Includes transmission losses and station service loads after curtailment.
[172] The load will not shed immediately after the loss of the LIL bipole but it will need to be shed pre-emptively in preparation for the next contingency.

requirements on the Avalon. However, up to 94.1% of load on the Avalon can be served by 2034 with the addition of the CT on the Avalon, reducing the load-shed requirement to 60 MW.

Similarly, should all additional generation be added off of the Avalon with no additional generation on the Avalon, as reflected in Scenario 4AEI (Minimum Investment Required), it would also result in 120 MW of Avalon load shedding requirements by 2034, despite investing in Option 4 transmission upgrades and reactive power support.

By advancing the CT build from 2034 to 2031 as depicted in Scenario 4AEF(ADV) (Minimum Investment Required), as much as 97.4% of peak load can be served in 2031, resulting in only approximately 25 MW of load-shedding requirements during a LIL bipole outage. Directly comparing Scenario 4AEF(ADV) (Minimum Investment Required) in Table 43, the approximately $150 million transmission upgrade achieves the ability to meet 94.7% of peak in 2031, corresponding to a load-shed requirement of approximately 50 MW, compared to 97.4% and approximately 30 MW if Option 4 + reactive power support was applied to completely remove the Bay d’Espoir to Soldiers Pond bottleneck. By 2034, 91.3% of peak can be served, corresponding to a 90 MW load-shed requirement with Option 4, compared to 94.1% and 60 MW load-shed requirement if reactive power support were installed at Sunnyside or Come by Chance,[173] which could cost an additional $200 million to $250 million.

7.3.3 Recommended Transmission Upgrades

Upon the retirement of the Holyrood TGS and Hardwoods GT on the Avalon, appreciable transmission bottlenecks will occur during a LIL bipole outage, resulting in trapped Off-Avalon generation. From a transmission planning perspective, if more generation is added off the Avalon, increased transmission capacity along the Bay d’Espoir to Soldiers Pond corridor is needed to reduce the amount of load shedding required on the Avalon during a LIL bipole outage, once the Holyrood TGS and Hardwoods GT are retired. Advancing as much On-Avalon generation as possible to improve system reliability would increase the amount of load that can be served.

The analysis indicates that the Option 4 transmission upgrade (which is a third line from Western Avalon to Soldiers Pond and DLR for TL201, TL202, TL206, TL203) for a total cost of approximately $150 million is recommended for all scenarios analyzed, as it is the lowest-cost option to meet Island demand in

[173] The exact location to be determined through further study.

combination with the Expansion Plans applied during a LIL bipole outage to keep Avalon load shed requirements below 100 MW.

From a transmission perspective, to alleviate the Bay d'Espoir to Soldiers Pond bottleneck, there is a definitive need for On-Avalon generation with SC capability to minimize transmission investment. The least-cost, On-Avalon capacity resource that meets these generation requirements is a CT. With this CT included in the Expansion Plan, associated transmission capacity requirements are understood and would be in the form of new infrastructure, as specified in Option 4, or through lower-cost steps to maximize transfer capacity through existing assets, including the implementation of an RAS and/or DLR technology. Hydro is actively working to understand the viability of the lower-cost option. However, both solutions are equivalent in terms of capacity and the outcomes of this analysis do not impact generation expansion recommendations.

As stated above, 100 MW has been specified as the maximum permitted shortfall for a LIL bipole outage. This limit ensures that shortfalls are within the range of what Newfoundland Power demonstrated the ability to rotate during the loss of load event in 2014. For this investigation, the philosophy of permitting a shortfall is aligned with a Minimum Investment Required approach. A further reduction or elimination of the shortfall would require additional investments beyond those recommended in this analysis. Therefore, it is proposed that deliberation on additional infrastructure investments to further mitigate shortfalls be deferred until decisions on the Minimum Investment Requirements have been reached.

As mentioned previously, Hydro is exploring whether lower-cost steps can be taken to maximize transfer capacity through existing assets, including the implementation of an RAS and/or DLR technology as technically equivalent options to the Option 4 transmission upgrades. An RAS would be designed to instantly shed customer load following a contingency event to avoid a transmission line overload and/or abnormal voltage conditions. The thermal rating of a transmission line is typically calculated based on a series of conservative inputs to account for the worst-case weather conditions. Using real-time data, DLR technology would allow Hydro to be less conservative and operate a line to its true capacity based on the weather and conductor conditions at that moment in time. Hydro must evaluate these options to determine if they are technically viable (individually or combined) for the Bay d'Espoir to Soldiers Pond transmission system.

A marginal level of increased reliability and resulting demand served is costly ($350 million to $400 million); however, it may eventually be required to support the level of Off-Avalon generation needed to support load growth on the Island Interconnected System. As stated previously, deliberations relating to the further mitigation of supply shortfalls should be deferred until decisions pertaining to the Minimum Investments Required have been reached. Hydro is continuing to perform additional analyses to determine the technical feasibility of lower-cost solutions to help alleviate the Bay d'Espoir to Soldiers Pond transmission constraints. More On-Avalon generation and/or the implementation of an RAS,[174] DLR, and transmission line redesign, could reduce the scope and/or cost of future transmission upgrades required to facilitate the proposed generation Expansion Plan. Therefore, the cost estimates presented in this analysis can potentially be considered the most expensive solution. These cost estimates were included in the total Expansion Plan cost, which is discussed in further detail in Section 7.4.1.

Hydro has taken the initiative to install DLR technology on TL201 as part of a pilot project. Once this DLR system is fully commissioned and enough data collected, Hydro will be able to better assess and quantify the potential value of applying the same technology to other 230 kV lines between Bay d'Espoir and Soldiers Pond. Hydro is currently working with TransGrid to perform a study to determine if an RAS is a technically viable solution to increase the transfer limits from Bay d'Espoir to Soldiers Pond.

7.4 Expansion Plan Iterative Process

Select Expansion Plans, including the transmission upgrade requirements identified in Section 7.3 were modelled in Hydro's Long-Term Financial Model to determine the impact of the required investment on customer rates, the load forecast, and select Expansion Plans. The results are presented in Sections 7.4.1 through 7.4.4.

7.4.1 The Expansion Plan and Rate Impacts

As rate mitigation had not been finalized prior to the development of the 2023 load forecast and the analysis presented in this report, the assumed mitigated rate that formed the basis of the rate included in the 2023 Reference Case load forecast was the target mitigated rate announced publicly by GNL in

[174] Cross-tripping load on the Avalon to offload 230 kV line flow following a contingency. Generation rejection may also be required to balance system frequency.

2019[175] and 2021,[176] targeting 14.7¢/kWh, escalating by 2.25% per year. This rate forecast was used in both the Reference Case and Accelerated Decarbonization.[177] For Slow Decarbonization, Hydro created an assumed rate sensitivity forecast considering the underlying mitigated electricity rate forecast described herein and added a 0.7% adjustment based on the historical rate impact for distribution upgrades on Newfoundland Power's system. Although the final rate mitigation plan is largely aligned with the assumptions used in the 2023 Reference Case load forecast, there are some differences in rate assumptions, primarily in the early years. These differences have been captured through the analysis performed on RS2.

Two additional rate sensitivities were applied against the Scenario 4AEF (Minimum Investment Required) Expansion Plan to further test the impact of rates on the plan:

- **RS1**: Rate increases for July 1, 2024 and July 1, 2025 would be based on applications currently before the Board, estimated at the time to be between 5.90% and 7.50% each year for Newfoundland Power plus 2.25% for Hydro's costs. Rate increases in 2026 include 2.25% for Hydro's costs and 0.4% for Newfoundland Power's costs and, starting in 2027, include 2.25% for Hydro's costs plus an estimated 0.7% per year for Newfoundland Power's costs. This level of rate increase will continue until 2030 at which point rates will be phased into the unmitigated rate. This scenario assumes no rate mitigation beyond 2030, resulting in annual 7.5% rate increases until 2035 to fully phase into the unmitigated rate, and includes expansion builds being placed in-service during the study period.
- **RS2**: Rate increases for July 1, 2024 and July 1, 2025 would be based on applications currently before the Board, estimated at the time to be between 5.90% and 7.50% each year for Newfoundland Power plus 2.25% for Hydro's costs. Rate increases in 2026 include 2.25% for Hydro's costs and 0.4% for Newfoundland Power's costs and, starting in 2027, include 2.25% for Hydro's costs plus an estimated 0.7% per year for Newfoundland Power's costs. This level of rate increase will continue until 2030. This scenario assumes rate mitigation will continue beyond

[175] "Protecting You from the Cost Impacts of Muskrat Falls," Government of Newfoundland and Labrador, April 2019. https://www.gov.nl.ca/iet/files/Framework.pdf
[176] GNL's rate mitigation target of 14.7 ¢/kWh, escalating at 2.25% per year, as referenced in the "Technical Briefing Rate Mitigation," Government of Newfoundland and Labrador, July 28, 2021, filed as part of the "Items Impacting the Delay of Hydro's Next General Rate Application – Further Update," Newfoundland and Labrador Hydro, August 27, 2021. http://pub.nl.ca/indexreports/nextgeneral/From%20NLH%20-%20Filing%20of%20Next%20General%20Rate%20Application%20-%20Further%20Update%20-%202021-08-27.PDF
[177] Please refer to Section 6.1 for further detail on the load forecast scenarios developed for the Island Interconnected System.

2030 but will not include/mitigate any costs related to additional generation expansion builds being placed in-service during the study period.

Although the rate mitigation plan does not currently provide certainty around the period post-2030, GNL has stated publicly that it is committed to keeping rates affordable for the people of the province. Rate sensitivities described herein were used to test the Expansion Plans against changes in assumptions around rate mitigation post-2030. Hydro will work with GNL in advance of 2030 to determine future rate mitigation requirements once more information on the landscape of the electricity sector in that period is known and the rate impacts of required system expansion are better understood. Lastly, this analysis and the rates provided herein are estimates based on assumptions made at a point in time and are provided to inform the implications of expansion only. Actual customer rates in this period could differ from those outlined herein for a variety of reasons, including assumptions around rate mitigation post-2030, actual customer load volume versus that which is assumed in the forecast, etc.

For the purposes of the analysis conducted for this study, the rate scenarios analyzed are summarized as follows:

- The base rate, or assumed mitigated rate, was applied to the Reference Case;[178]
- A higher rate sensitivity was applied to the assumed mitigated rate and was applied to Slow Decarbonization; and
- Two additional rate sensitivities were applied against the Scenario 4AEF (Minimum Investment Required) Expansion Plan.

The results of the analysis are summarized in Table 45 through Table 49. The recommended least-cost transmission expansion (Option 4), as identified in Section 7.3 was included in the analysis to provide a fulsome impact of the Expansion Plan requirements on rates. However, as previously mentioned, alternative means are being pursued to significantly reduce the transmission investment (i.e., implementation of DLR and/or an RAS). In addition, export sales are not included in these cost estimates, although it is reasonable to consider that there will likely be excess energy in the non-winter period that can be exported, thus reducing the revenue requirements presented below. In addition, wind was modelled in the Expansion Plan with a capital cost (see Table 1 in Section 4.0); however, Hydro

[178] The base rate was also applied to Accelerated Decarbonization; however, this load forecast was not selected for inclusion in the iterative process.

does not intend to construct wind, rather intends to meet the necessary energy requirements via a power purchase agreement. Therefore, it is possible that the revenue requirements, and therefore rate impacts, could be further reduced in some cases than what is presented in this analysis.

As shown in Table 45, the Scenario 1AEF (Reference Case) Expansion Plan, including transmission upgrades, could add to the assumed rate projection by 4.28¢/kWh by the end of the study period. This assumes that rate mitigation for all of Hydro's costs excluding the expansion plan continues beyond 2030.

Table 45: Scenario 1AEF (Reference Case) Expansion Plan Rate Analysis

Scenario 1AEF (Reference Case)	2030	2031	2032	2033	2034
Domestic Rate: 2023 Reference Case (¢/kWh)	17.56	17.96	18.36	18.78	19.20
Expansion Plan Impact					
Domestic Rate (¢/kWh)	18.25	20.82	22.14	22.60	23.48
Domestic Rate Variance: (¢/kWh)	0.69	2.86	3.78	3.82	4.28
Incremental Revenue Requirement ($000)	47,155	199,753	269,734	277,256	315,233

As shown in Table 46, the Scenario 4AEF (Minimum Investment Required) Expansion Plan, including transmission upgrades, could add to the current rate projection by 2.94¢/kWh by the end of the study period. This assumes that rate mitigation for all of Hydro's costs excluding the Expansion Plan continues beyond 2030.

Table 46: Scenario 4AEF (Minimum Investment Required) Expansion Plan Rate Analysis

Scenario 4AEF (Minimum Investment Required)	2030	2031	2032	2033	2034
Domestic Rate: 2023 Slow Decarbonization Case (¢/kWh)	18.57	19.12	19.68	20.27	20.87
Expansion Plan Impact					
Domestic Rate (¢/kWh)	18.90	21.02	22.02	22.60	23.81
Domestic Rate Variance (¢/kWh)	0.33	1.90	2.34	2.33	2.94
Incremental Revenue Requirement ($000)	21,617	126,622	158,761	159,277	203,521

Scenario 4AEF (Minimum Investment Required) was analyzed against two rate sensitivities and the analysis is provided in Table 47 and Table 48. Comparing RS1, should rate mitigation end in 2030, followed by 7.5% annual increases to phase into the unmitigated rate, the rate impact is 25.14¢/kWh by 2034 compared to 23.81¢/kWh that was identified in Scenario 4AEF (Minimum Investment Required). Therefore, while it is not expected, should rate mitigation not continue beyond 2030, an increase of 1.33¢/kWh could occur by 2034.

Table 47: Scenario 4AEF (Minimum Investment Required) RS1

Scenario 4AEF (Minimum Investment Required) RS1	**2030**	**2031**	**2032**	**2033**	**2034**
Domestic Rate: RS1 (¢/kWh)[179]	19.29	19.85	20.44	21.04	21.66
Expansion Plan and Phase in Impact[180]					
Domestic Rate (¢/kWh)	19.29	20.24	21.76	23.39	25.14
Scenario 4AEF (Minimum Investment Required)					
Domestic Rate (¢/kWh)	18.90	21.02	22.02	22.60	23.81
Domestic Rate Variance (¢/kWh)	0.39	(0.78)	(0.26)	0.79	1.33
Incremental Revenue Requirement ($000)[181]	-	-	-	-	-

1 Comparing Scenario 4AEF (Minimum Investment Required) against RS2, the rate impact is 24.61¢/kWh
2 by 2034 compared to 23.81¢/kWh that was identified in Scenario 4AEF (Minimum Investment Required);
3 an increase of 0.80¢/kWh by 2034.

Table 48: Scenario 4AEF (Minimum Investment Required) RS2

Scenario 4AEF (Minimum Investment Required) RS2	**2030**	**2031**	**2032**	**2033**	**2034**
Domestic Rate: RS2 (¢/kWh)[182]	19.29	19.85	20.44	21.04	21.66
Expansion Plan Impact					
Domestic Rate (¢/kWh)	19.61	21.76	22.78	23.37	24.61
Scenario 4AEF (Minimum Investment Required)					
Domestic Rate (¢/kWh)	18.90	21.02	22.02	22.60	23.81
Domestic Rate Variance (¢/kWh)	0.71	0.74	0.76	0.77	0.80
Incremental Revenue Requirement ($000)[183]	-	-	-	-	-

4 As shown in Table 49, the Scenario 4AEF (ADV) (Minimum Investment Required) Expansion Plan could
5 add to the current rate projection by 3.22¢/kWh by the end of the study period. This assumes that rate
6 mitigation for all of Hydro's costs excluding the Expansion Plan continues beyond 2030. Compared to
7 Scenario 4AEF (Minimum Investment Required) in Table 46, by advancing the second capacity option to
8 2031, the rate impact is an additional 0.68¢/kWh in the same year, and an additional 0.28¢/kWh by the
9 end of the study period.

[179] The forecast rate assumes rate mitigation continues post 2030 inclusive of all Hydro's costs.
[180] This scenario assumes no rate mitigation beyond 2030, resulting in annual 7.5% rate increases to phase into the unmitigated rate.
[181] The revenue requirement remains the same as Scenario 4AEF (Minimum Investment Required).
[182] The forecast rate assumes rate mitigation continues post 2030 inclusive of all Hydro's costs.
[183] The revenue requirement remains the same as Scenario 4AEF (Minimum Investment Required).

Table 49: Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan Rate Analysis

Scenario 4AEF(ADV) (Minimum Investment Required)	2030	2031	2032	2033	2034
Domestic Rate: 2023 Slow Decarbonization Case (¢/kWh)	18.57	19.12	19.68	20.27	20.87
Expansion Plan Impact					
Domestic Rate (¢/kWh)	18.80	21.70	22.93	23.50	24.09
Domestic Rate Variance (¢/kWh)	0.33	2.58	3.25	3.23	3.22
Incremental Revenue Requirement ($000)	21,627	160,349	206,899	206,817	212,967

Figure 7 provides a summary of the revenue requirements between each scenario for the years 2030 through to 2034 for comparison.

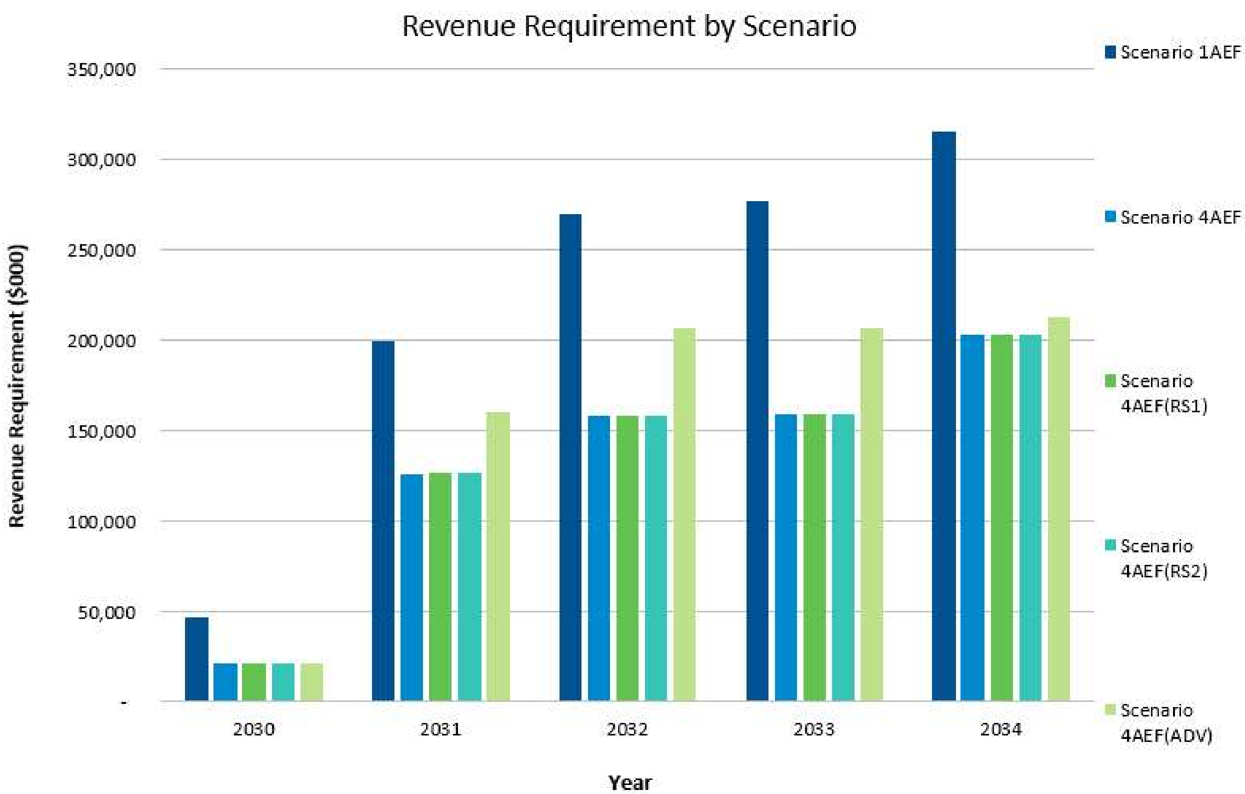


Figure 7: Revenue Requirement by Scenario

Overall, all the Scenario 4 (Minimum Investment Required) Expansion Plan sensitivities and rate sensitivities that were considered in this analysis have similar revenue requirements throughout the period. There is no difference in revenue requirements between Scenario 4AEF (Minimum Investment Required) compared to the two rate sensitivities that were applied. While the revenue requirement for Scenario 4AEF (ADV) (Minimum Investment Required) is approximately 25% to 30% higher in the years

2031 through 2033, due to advancing the in-service date of a CT, the revenue requirement nearly equalizes by the end of the study period in 2034, resulting in approximately an additional 5% of increased revenue requirements. Alternatively, Scenario 1AEF (Reference Case), requires an additional 25% to 118% of increased revenue requirements compared to Scenario 4AEF (ADV) (Minimum Investment Required) through the study period. By 2034, the additional revenue requirement is approximately 48% when comparing the two Expansion Plan scenarios.

7.4.2 The Expansion Plan and Load Forecast Impacts

As a commodity, the demand for electricity is elastic, meaning that electricity customers exhibit some sensitivity to price. Projected investment costs likely increase projected electricity rates, resulting in a decrease in forecast customer load requirements. To further test the rate impacts determined in Section 7.4.1, the new (higher) rates were run through the load forecast model to determine the impact on the long-term load forecast, all other things being equal. Select Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required) Expansion Plans were used for inclusion in this analysis.

Table 1 compares the rates included in the initial Island Interconnected System Reference Case load forecast compared to the load forecast iteration for Scenario 1AEF (Reference Case) at the end of the study period (2034). Comparing Scenario 1AEF (Reference Case) to the initial Reference Case load forecast, there is a potential decrease of approximately 70 MW and 380 GWh, representing a 3.3% to 3.6% decrease in capacity requirements and a 3.8% to 4.1% reduction in energy requirements by 2034.

Table 50: Scenario 1 (Reference Case) Iteration Comparison in 2034[184]

	2034 Values			Difference		
	MW	GWh	¢/kWh	MW	GWh	¢/kWh
Reference Case	1,925	9,172	19.20	-	-	-
Scenario 1AEF	1,856	8,796	23.48	(69)	(376)	4.28

The difference in capacity and energy requirements through the study period is further demonstrated in Chart 29 and Chart 30. The Y-axis does not go to zero in each graph, making the differential look larger.

[184] Compared against the Island Interconnected System Reference Case load forecast.

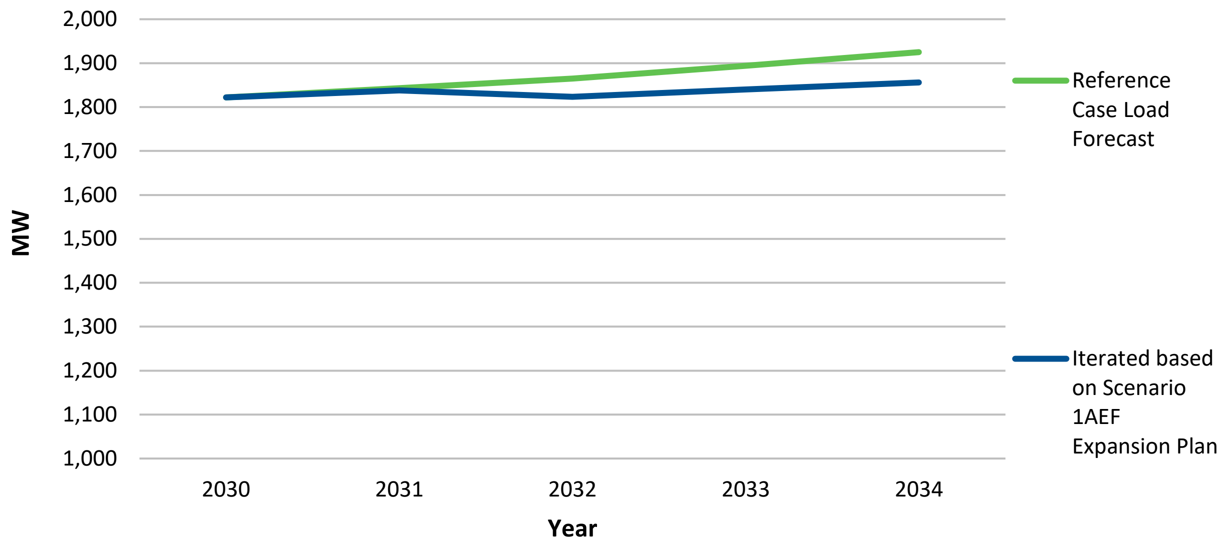


Chart 29: Scenario 1 (Reference Case) Iteration Comparison (MW)[185]

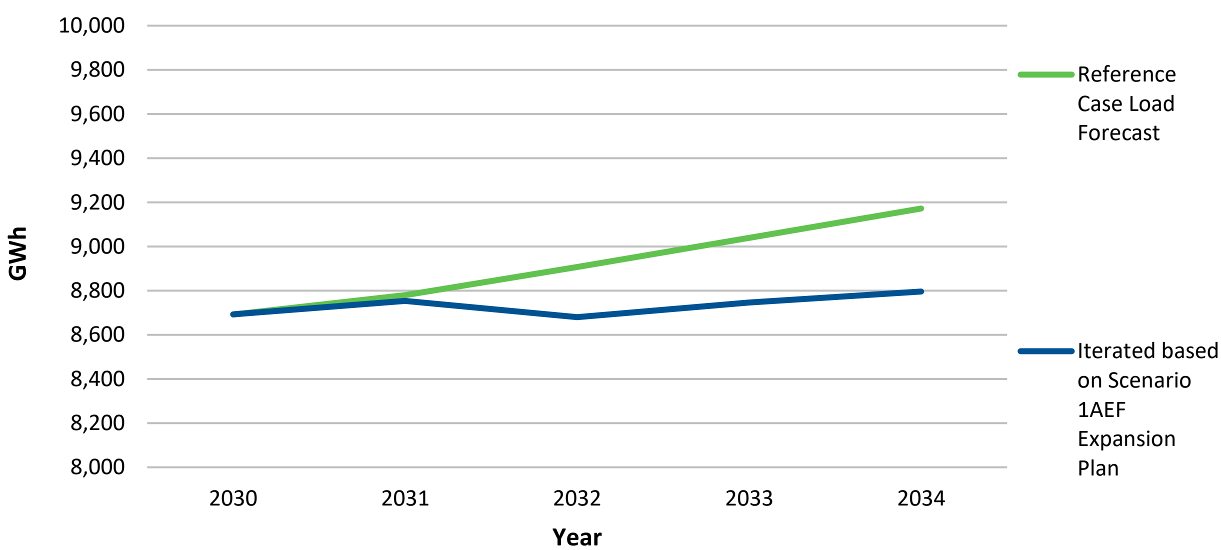


Chart 30: Scenario 1 (Reference Case) Iteration Comparison (GWh)[186]

1 Table 51 compares the Island Interconnected System Slow Decarbonization load forecast and the load
2 forecast iterations for Scenario 4AEF (Minimum Investment Required), Scenario 4AEF(ADV) (Minimum
3 Investment Required), Scenario 4AEF (Minimum Investment Required) with RS1, and Scenario 4AEF
4 (Minimum Investment Required) with RS2. Comparing all scenarios to the initial Slow Decarbonization

[185] The Y-axis begins at 1,000 MW to allow the reader to better visualize the differential between scenarios.
[186] The Y-axis begins at 8,000 GWh to allow the reader to better visualize the differential between scenarios.

load forecast, there is a potential decrease of approximately 36 MW to 48 MW and 192 GWh to 259 GWh, representing a 1.9% to 2.6% reduction in capacity requirements and a 2.2% to 3.0% reduction in energy requirements by 2034.

Table 51: Scenario 4 (Minimum Investment Required) Iteration Comparison in 2034[187]

	2034 Values			Difference		
	MW	**GWh**	**¢/kWh**	**MW**	**GWh**	**¢/kWh**
Slow Decarbonization	1,856	8,703	20.87	-	-	-
Scenario 4AEF	1,820	8,511	23.81	(36)	(192)	2.94
Scenario 4AEF(RS1)[188]	1,808	8,444	25.14	(48)	(259)	4.27
Scenario 4AEF(RS2)[189]	1,808	8,444	24.61	(48)	(259)	3.74
Scenario 4AEF(ADV)	1,810	8,456	24.09	(46)	(247)	3.22

The difference in capacity and energy requirements through the study period is further demonstrated in Chart 31 and Chart 32. The Y-axis does not go to zero in each graph, making the differential look larger. In each scenario that was iterated, there is minimal difference in both capacity and energy requirements by 2034.

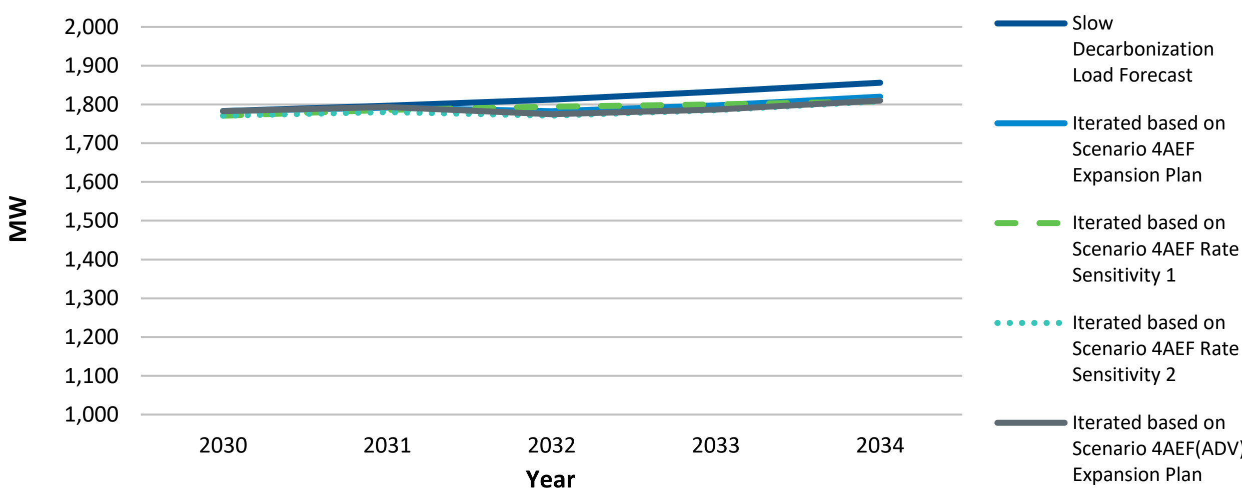


Chart 31: Scenario 4 (Minimum Investment Required) Iteration Comparison (MW)[190]

187 Compared against the Island Interconnected System Slow Decarbonization load forecast.
188 While there are differences in rates after 2029, the resulting changes in customer split between electric heat and non-electric heat due to rates over the 2030–2033 period and the forecast 2034 rate results in the same capacity and energy forecast in 2034 for both sensitivities.
189 While there are differences in rates after 2029, the resulting changes in customer split between electric heat and non-electric heat due to rates over the 2030–2033 period and the forecast 2034 rate results in the same capacity and energy forecast in 2034 for both sensitivities.
190 The Y-axis begins at 1,000 MW to allow the reader to better visualize the differential between scenarios.

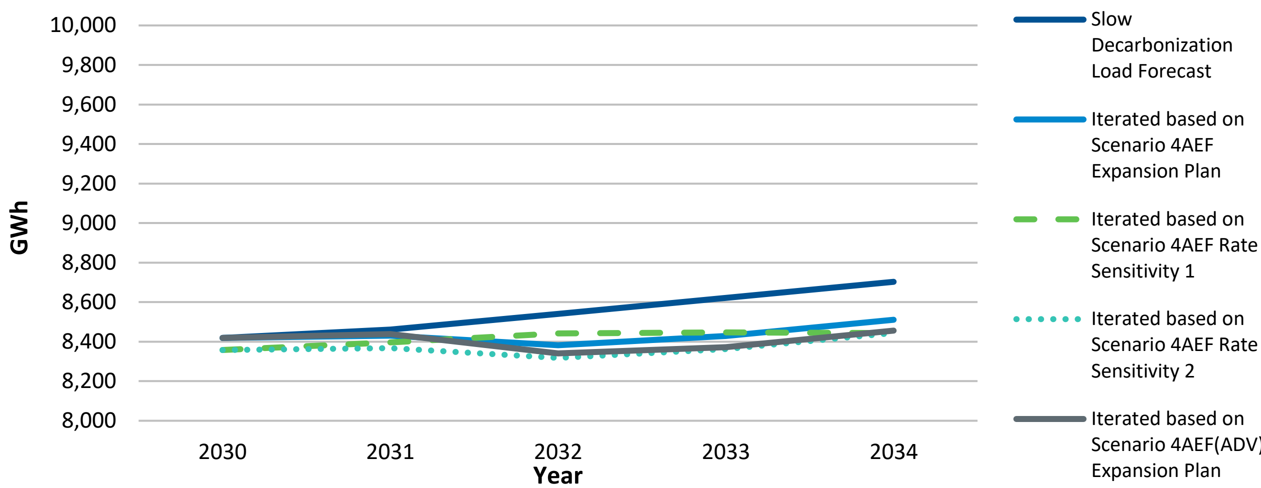


Chart 32: Scenario 4 (Minimum Investment Required) Iteration Comparison (GWh)[191]

7.4.3 Expansion Plan Iteration

To determine if the load decreases identified in Section 7.4.2 were material enough to defer the timing of the required investment, the Expansion Plans were re-run. The suffix ".1" is used to identify iterated Expansion Plan scenarios. The Expansion Plan Scenario 1AEF.1 (Reference Case) is summarized in Table 52.

Table 52: Scenario 1AEF.1 (Reference Case) – Iterated

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	1	1
CAT Unit 3	68.2	0		1	1	1	1
Wind 100 MW	22	350	2	4	4	4	4
Firm Capacity (MW)			44	452	452	452	452
Firm Energy (GWh)			700	1400	1400	1400	1400

Comparing the iterated Expansion Plan to the previous Scenario 1AEF (Reference Case) Expansion Plan, Table 39 in Section 6.3.4, it is evident that Bay d'Espoir Unit 8, a CT, and Cat Arm Unit 3 are still required by 2031. However, where previously a 50 MW proxy capacity resource was required in 2034, it has been

[191] The Y-axis begins at 8,000 GWh to allow the reader to better visualize the differential between scenarios.

pushed out of the study period. The iterated Expansion Plan results in a reduction in capacity build of 72 MW in 2034.

Unsurprisingly, the greatest impact on the decrease in load requirements is on the energy requirements. While 200 MW of wind is still required by 2030, only 400 MW of wind is required by the end of the study period, whereas previously, 500 MW of wind was identified to meet firm energy requirements by 2034. The iterated Expansion Plan results in a reduction in firm energy build of 0.35 TWh in 2034.

The results of Scenario 4AEF.1 (Minimum Investment Required) Expansion Plan are summarized in Table 53.

Table 53: Scenario 4AEF.1 (Minimum Investment Required) – Iterated

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
Wind 100 MW	22	350	1	3	3	3	4
Firm Capacity (MW)			22	220	220	220	242
Firm Energy (GWh)			350	1050	1050	1050	1400

Comparing the iterated Expansion Plan to the previous Scenario 4AEF (Minimum Investment Required) Expansion Plan, Table 39 in Section 6.3.4, Bay d'Espoir Unit 8 is still required by 2031. However, where previously the CT was required by 2034, the second capacity resource is no longer required within the study period. Therefore, the iterated Expansion Plan results in a reduction in capacity build of 142 MW in 2034.

As for the energy requirements, 100 MW of wind is still required by 2030, increasing to 300 MW by 2031 and 400 MW by the end of the study period. In the non-iterated load forecast, 400 MW of wind was needed to meet firm energy requirements by 2031. The iterated Expansion Plan does not result in a reduction in firm energy build in 2034; however, there is a potential reduction of 0.35 TWh for the years 2031 through 2033.

Scenario 4AEF(ADV) (Minimum Investment Required) was not iterated because it is not a direct outcome of the Expansion Model, as the second capacity resource was advanced to 2031 by Hydro as it has other reliability benefits (i.e., transmission constraint and LIL shortfall) but is not required to meet the probabilistic planning criteria requirements built into the Expansion Model. Going forward, Scenario 4AEF(ADV).1 refers to the iterated Scenario 4AEF.1 (Minimum Investment Required) with the second capacity resource (142 MW CT) added in 2031.

7.4.4 Shortfall Analysis on Iterated Expansion Plan

To extend the iteration of Scenario 4AEF (Minimum Investment Required) and Scenario 4AEF(ADV) (Minimum Investment Required) through all components of the analysis, shortfall analyses were completed to assess the reliability of the Island Interconnected System in the event of a prolonged LIL outage in the winter.

As illustrated in Chart 33, for Scenario 4AEF.1 (Minimum Investment Required), in the reference year 2032, under the Average Case (green line), unserved energy is expected to occur for 76 hours (8% of the time), totalling 4 GWh of energy shortfall. The supply shortfall would occur primarily during peak hours, with the highest anticipated shortfall estimated to be 186 MW. Under the Severe Case (blue line), the peak shortfall is estimated to be 297 MW with 266 hours of unserved energy over the period (26% of the time), totalling 21 GWh of energy shortfall.

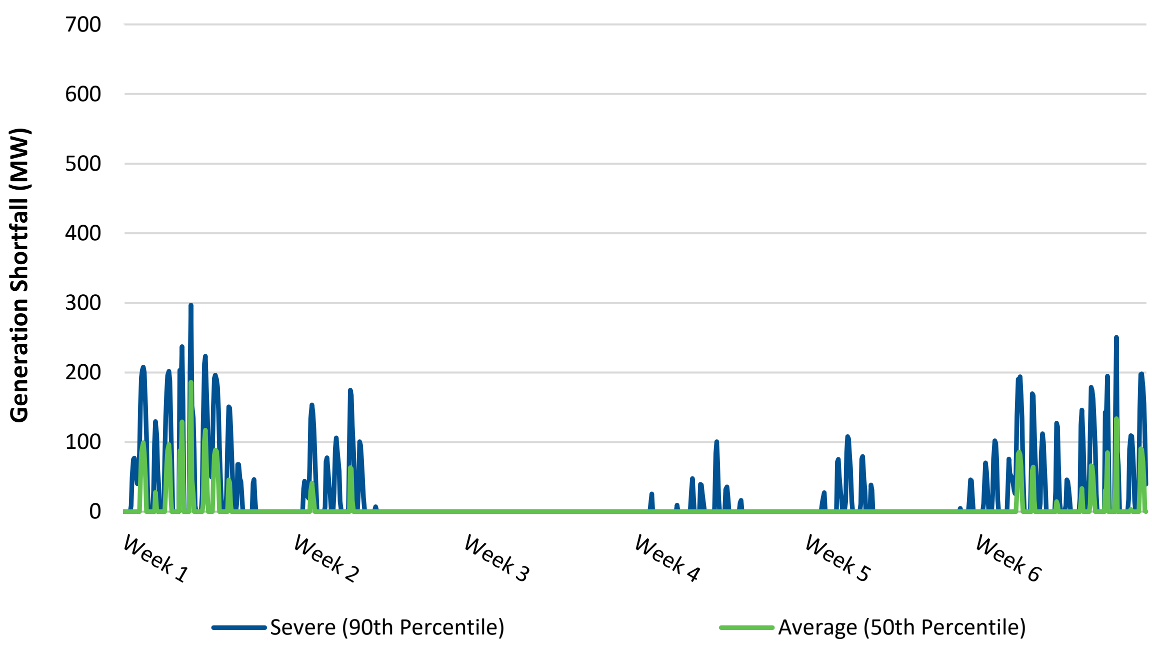


Chart 33: Shortfall over Six Weeks
(Scenario 4AEF.1 (Minimum Investment Required) Iterated Load and Expansion Plan)

1 Chart 34 shows the estimated unserved energy on the peak day in the 2032 reference year.

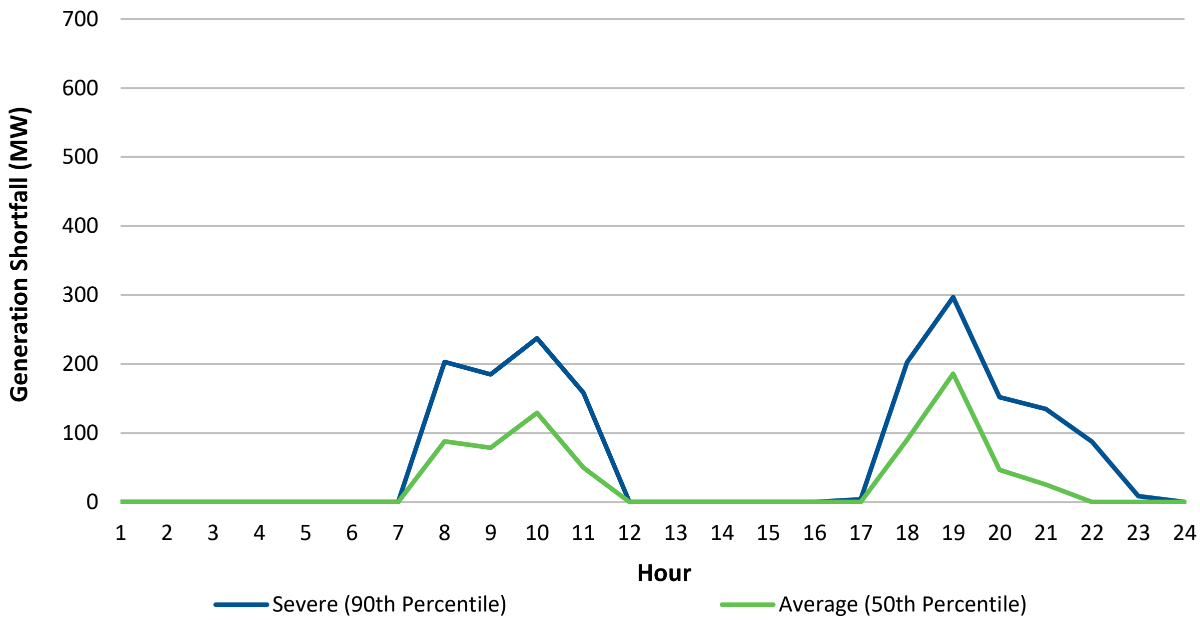


Chart 34: Shortfall on Peak Day (Scenario 4AEF.1 (Minimum Investment Required) Iterated Load and Expansion Plan)

2 Chart 35 depicts the shortfall duration curve for this iterated scenario. In the Average Case, a supply
3 shortfall of 100 MW or higher is expected approximately 1% of the time. In the Severe Case, a supply
4 shortfall of 100 MW or higher is expected approximately 8% of the time.

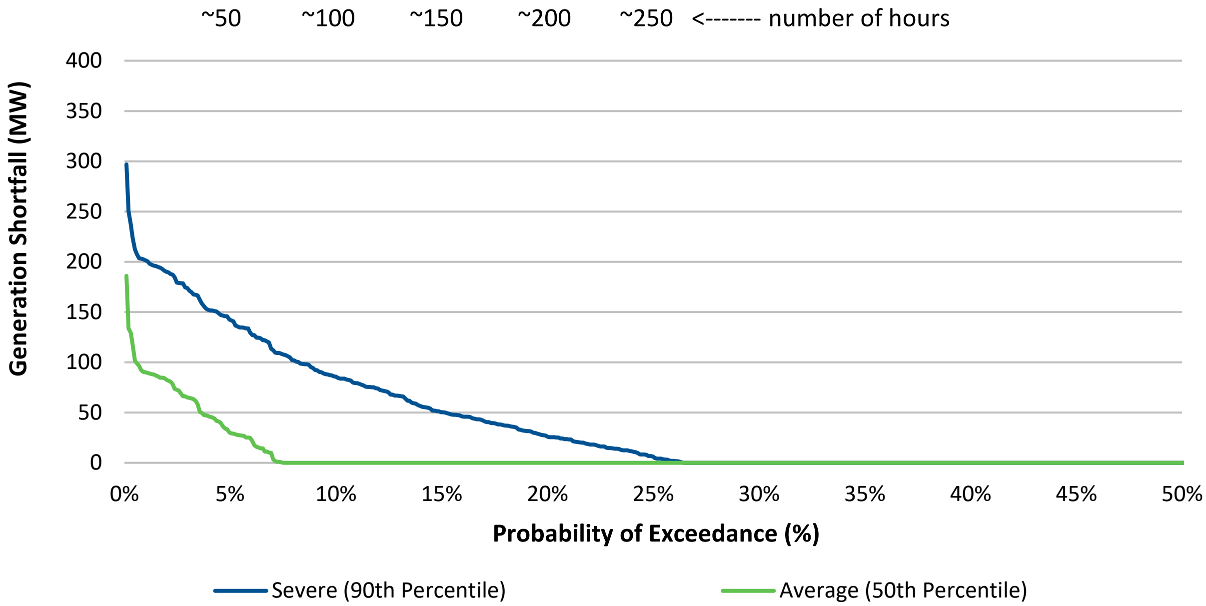


Chart 35: Shortfall Duration Curve (Scenario 4AEF.1 (Minimum Investment Required) Iterated Load and Expansion Plan)

As mentioned previously, the Scenario 4AEF(ADV).1 (Minimum Investment Required) Expansion Plan is assumed to be the same as Scenario 4AEF.1 (Minimum Investment Required) but includes a second capacity resource (142 MW CT) in 2031.As Chart 36 shows, for Scenario 4AEF(ADV).1 (Minimum Investment Required), in the reference year 2032 and under the Average Case (green line), unserved energy is expected to occur for only 1 hour, totalling 0.1 GWh of energy shortfall. The 1 hour of shortfall is estimated to have a magnitude of 50 MW. Under the Severe Case (blue line), the peak shortfall is estimated to be 169 MW with 55 hours of unserved energy over the six-week analysis period (5% of the time), totalling 2 GWh of energy shortfall.

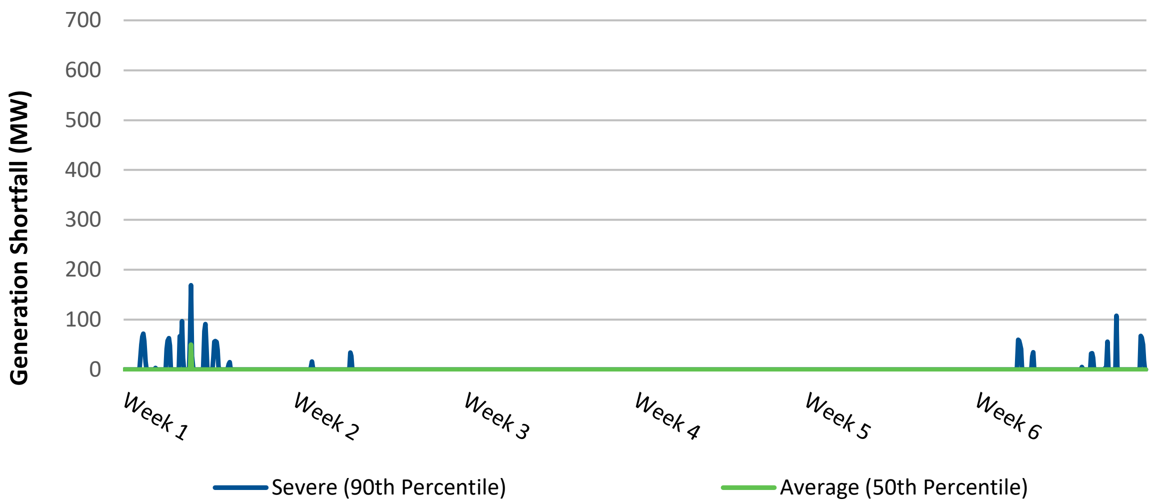


Chart 36: Shortfall over Six Weeks
(Scenario 4AEF(ADV).1 (Minimum Investment Required) Iterated Load)

1 Chart 37 shows the estimated unserved energy on the peak day in the 2032 reference year.

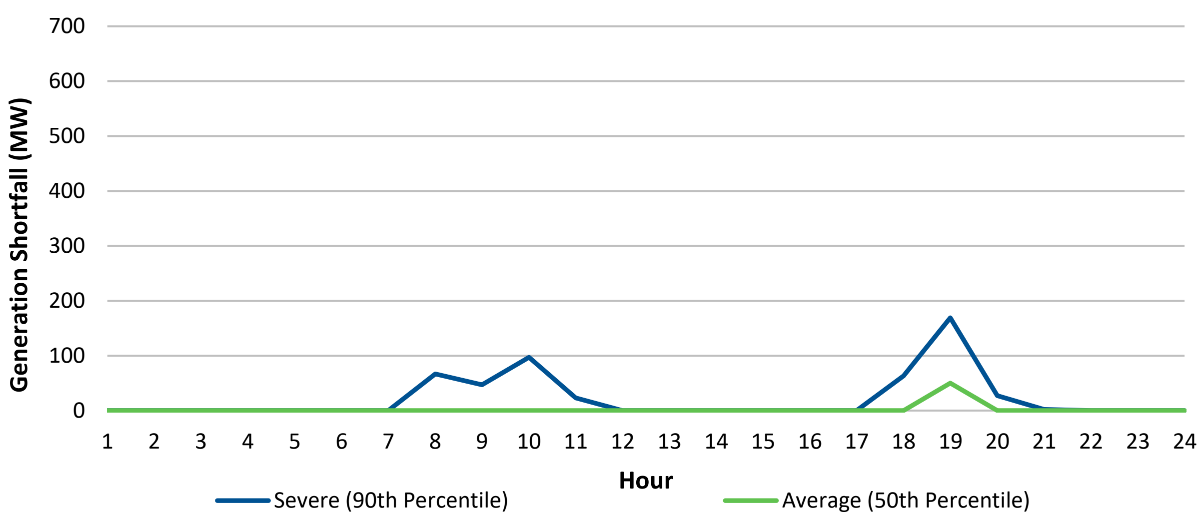


Chart 37: Shortfall on Peak Day (Scenario 4AEF(ADV).1 (Minimum Investment Required) Iterated Load)

2 Chart 38 depicts the shortfall duration curve for this iterated scenario. In the Average Case, a supply
3 shortfall of 100 MW or higher is never experienced. In the Severe Case, a supply shortfall of 100 MW or
4 higher is expected only 0.2% of the time.

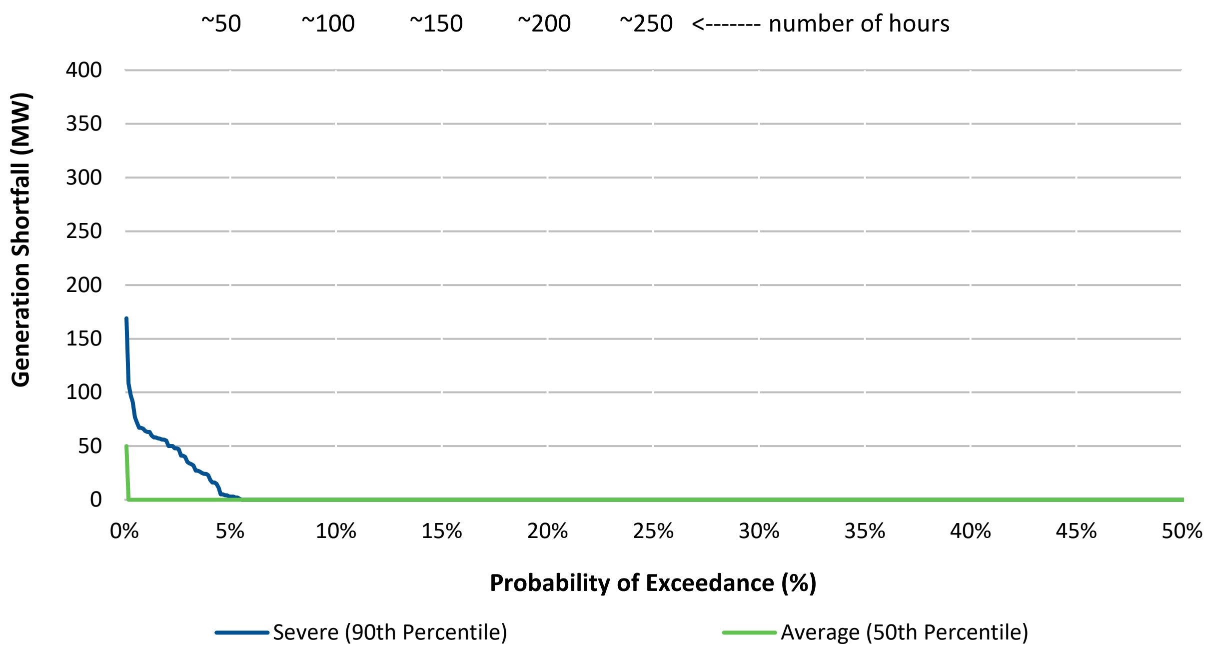


Chart 38: Shortfall Duration Curve
(Scenario 4AEF(ADV).1 (Minimum Investment Required) Iterated Load)

Based on the results of the shortfall analysis on Scenario 4AEF.1 (Minimum Investment Required), it is clear that not building a second capacity resource would have considerable supply shortage implications in the event of a prolonged LIL outage in winter. The shortfall analysis of Scenario 4AEF(ADV).1 (Minimum Investment Required) on the other hand (which includes a CT in 2031) leads to much lower levels of supply shortfall.

In addition, in Section 5.1.4.2 of Appendix B, Hydro identified that during the six-week period it anticipates being able to call upon CBPP capacity assistance at a reduced amount of 50 MW, recognizing it is a conservative approach. By advancing the second capacity resource option, as identified in Scenario 4AEF(ADV).1 (Minimum Investment Required), shortfall is mitigated to such a degree that it is likely that CBPP can provide the full capacity assistance amount of 90 MW during this period, thus reducing the shortfall by up to an additional 40 MW than identified.

8.0 Recommended Expansion Plan

The recommended Expansion Plan and how it meets Hydro's planning criteria is presented in Sections 8.1 and 8.2.

8.1 Minimum Investment Required Expansion Plan

LIL reliability, protecting the system against LIL bipole trips, and load growth are the main drivers of capacity and energy requirements in Hydro's Expansion Plans. Recognizing the uncertainties that remain for each, Hydro's strategy in this filing is to recommend an Expansion Plan that meets reliability criteria under the Minimum Investment Required scenario while balancing cost and environmental considerations. This strategy considers a highly reliable LIL (1% LIL bipole EqFOR) and Slow Decarbonization. Hydro recognizes that this Expansion Plan does not meet the reliability requirements of the Reference Case, or Expected Case, which considers a 5% LIL bipole EqFOR and Reference Case. However, it does identify resource options that should be immediately pursued for advancement in the regulatory process, as these resources are common to all scenarios considered. The need for additional resources, even in the Minimum Investment Required, is substantial and Hydro considers this the first step. Should load grow beyond the Slow Decarbonization and/or LIL bipole EqFOR be greater than 1%, the Minimum Investment Required Expansion Plan will not meet reliability requirements on the Island Interconnected System. Therefore, Hydro is proposing this first step while continuing to study additional requirements beyond what is proposed in the Minimum Investment Required Expansion Plan.

The recommended Expansion Plan being put forward is Scenario 4AEF(ADV).1 (Minimum Investment Required), which is summarized in Table 54. This Expansion Plan includes Bay d'Espoir Unit 8 and a CT coming into service in 2031 and up to 400 MW of wind energy by 2034 to meet firm energy planning criteria, resulting in approximately an additional 385 MW and 1.4 TWh added to the Island Interconnected System within the next ten years.

Table 54: Recommended Expansion Plan

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
CT	141.6	0		1	1	1	1
Wind 100 MW	22	350	1	3	3	3	4
Firm Capacity (MW)			22	362	362	362	384
Firm Energy (GWh)			350	1050	1050	1050	1400

While this shows the requirement for capacity in 2031, in reality, Hydro is working to advance both capacity resources as fast as possible to reduce the reliance on aging thermal assets.

The recommended Expansion Plan achieves the following:

- Meets the load growth considered in the Island Interconnected System Slow Decarbonization load forecast;
- Meets all prescribed planning criteria considering the Slow Decarbonization load forecast and a highly reliable LIL (1% LIL bipole EqFOR);
- Meets Hydro's firm energy criteria for the Slow Decarbonization load forecast;
- Balances cost and reliability under a prolonged LIL bipole outage by ensuring rotating outages are reasonably within what has been experienced on the system before;
- Considers the least-cost transmission upgrade required to alleviate the On-Avalon bottleneck during a LIL bipole outage;[192]
- Includes an On-Avalon unit with SC capability to help alleviate On-Avalon transmission bottlenecks that occur during a LIL bipole outage once aging On-Avalon assets are retired;
- Considers known diesel fuel restrictions on the Island;
- Helps to reduce the reliance on aging thermal assets and meet the retirement of these assets by 2030;
- Bay d'Espoir Unit 8 has the ability to support Hydro's annual maintenance outage requirements, which have been increasing due to aging assets in Hydro's existing fleet;
- Expected to adhere to the draft *CER* and includes consideration for a CT that has the ability to convert to a renewable fuel source in the future;
- Provides asset diversity with the combination of thermal, hydro, and energy resources; and
- Includes the resource options that reflect the substantial first step towards meeting the Reference Case requirements and/or the planning criteria determined for a LIL bipole EqFOR of 5%.

Chart 39 and Chart 40 present the load resource balance, including the recommended Expansion Plan under Scenario 4 conditions (Slow Decarbonization load forecast and 1% LIL bipole EqFOR). The load in

[192] As mentioned in Section 7.3, Hydro is actively trying to reduce the identified least-cost transmission upgrade through the implementation of an RAS and/or DLR.

these plots reflects the iteration that was completed to account for the cost of the Expansion Plan (and associated impact on demand) as identified in Section 7.4.2. As shown in Chart 39, the recommended Expansion Plan exceeds the requirements when comparing to planning reserve requirement only. The additional capacity is recommended based on the shortfall analysis, to improve reliability in the event of a prolonged LIL outage. Chart 40 illustrates that just enough wind energy is recommended to meet firm energy requirements in this scenario.

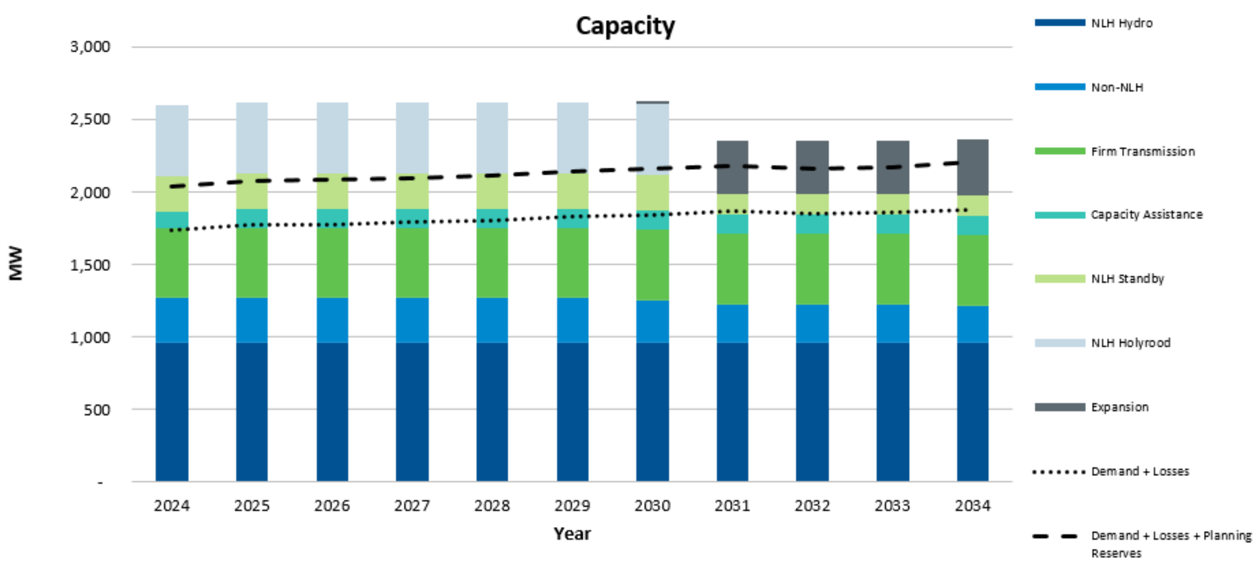


Chart 39: Capacity Load Resource Balance
(Slow Decarbonization Load Forecast (Iterated), 1% LIL EqFOR)

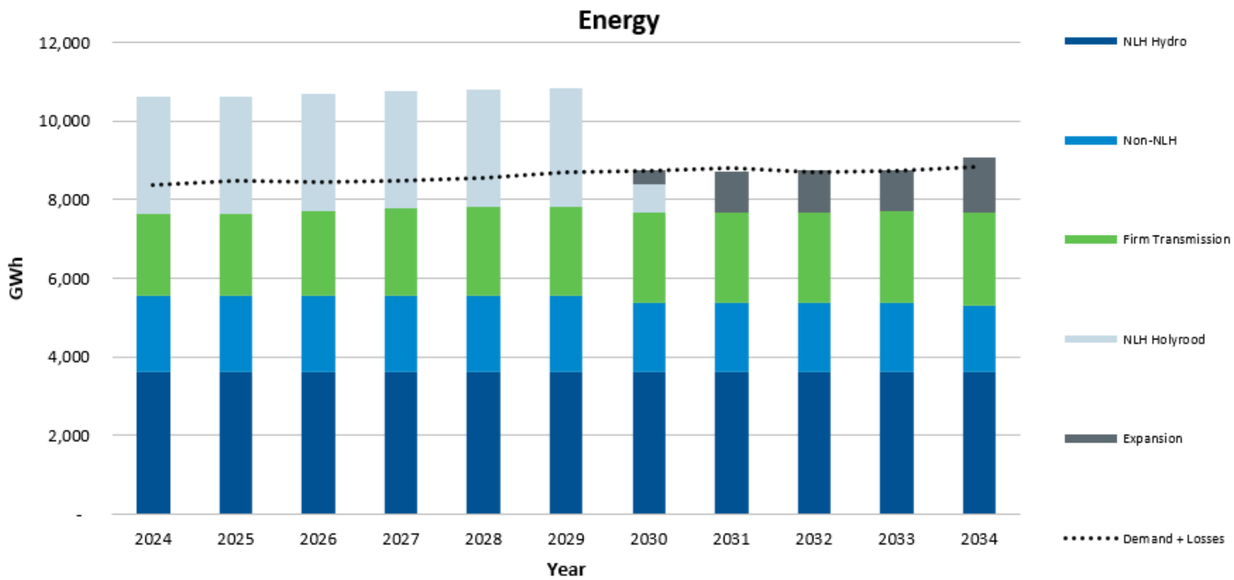


Chart 40: Energy Load Resource Balance (Slow Decarbonization Load Forecast (Iterated))

Chart 41 and Chart 42 present the load resource balance, including the recommended Expansion Plan under Scenario 1 conditions (Reference Case load forecast and 5% LIL bipole EqFOR). The load in these plots reflects the original forecast and does not account for the potential load reduction associated with the cost of the Expansion Plan.[193] As shown in Chart 41 and Chart 42, there remains a gap in both capacity and energy between the recommended Expansion Plan and requirements to meeting planning criteria under Scenario 2 conditions.

[193] While the Reference Case load forecast was iterated, it was done so based on Scenario 1 conditions (Reference Case load forecast and 5% LIL bipole EqFOR) Expansion Plan. Therefore, Hydro felt it was prudent to not combine the Scenario 4AEF(ADV).1 (Minimum Investment Required) Expansion Plan with an iterated Reference Case load forecast that is based on a different Expansion Plan.

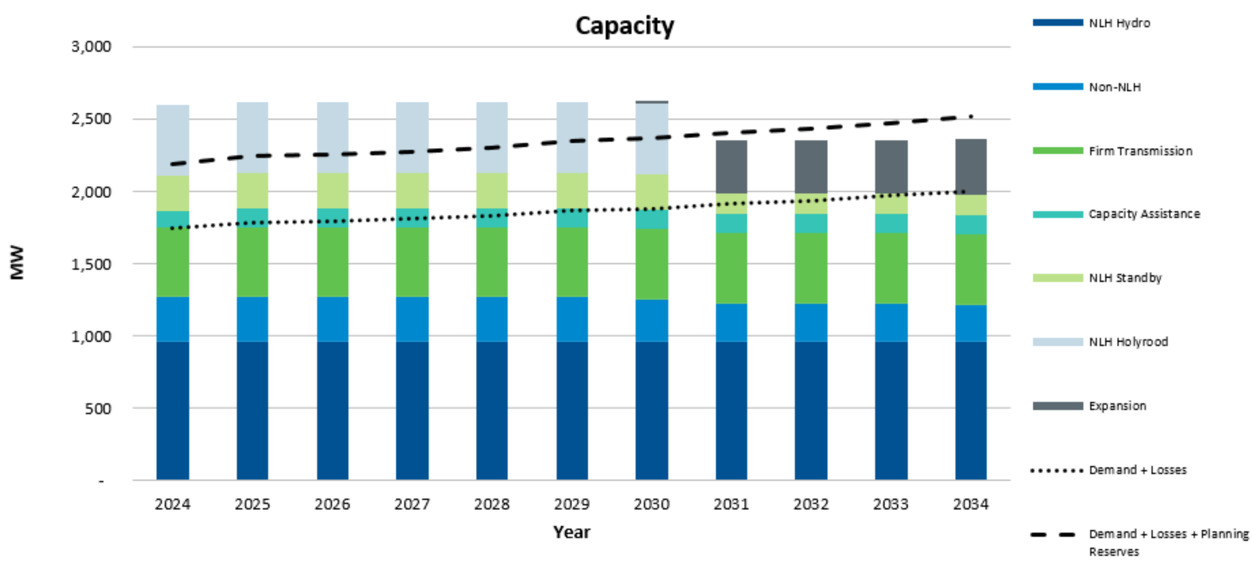


Chart 41: Capacity Load Resource Balance (Reference Case Load Forecast, 5% LIL bipole EqFOR)

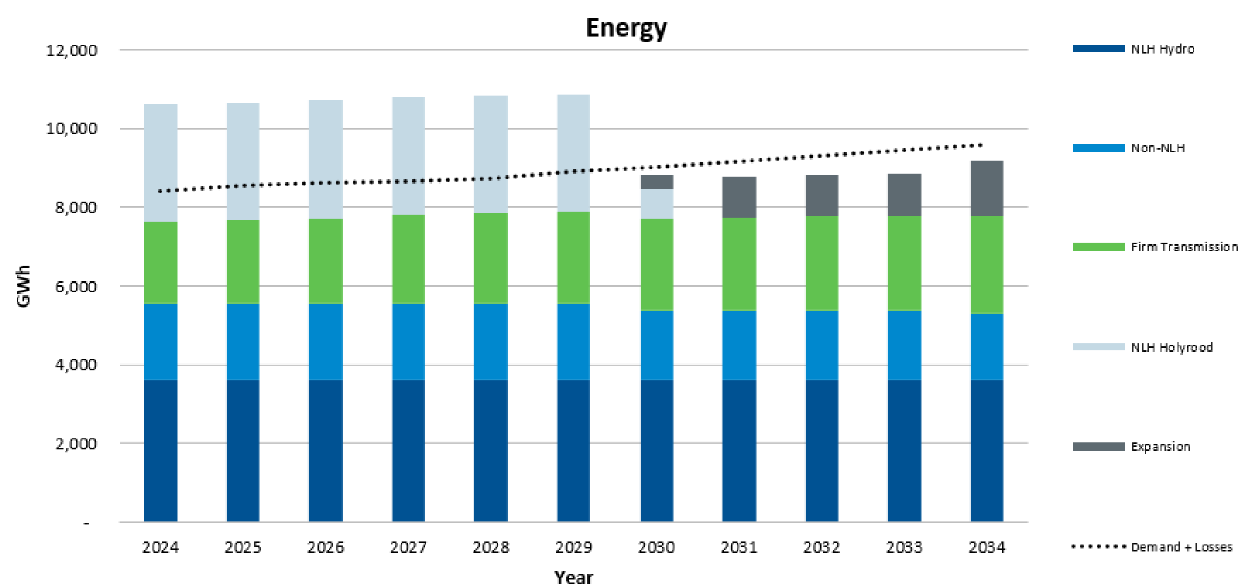


Chart 42: Energy Load Resource Balance (Reference Case Load Forecast)

1 Chart 43 and Chart 44 present the load resource balance, including the recommended Expansion Plan
2 under Scenario 2 conditions (Accelerated Decarbonization load forecast and 5% LIL bipole EqFOR). The
3 load in these plots reflects the original forecast and does not account for the potential load reduction
4 associated with the cost of the Expansion Plan. As shown in Chart 43 and Chart 44, there remains a gap

1 in both capacity and energy between the recommended Expansion Plan and requirements to meeting
2 planning criteria under Scenario 1 conditions.

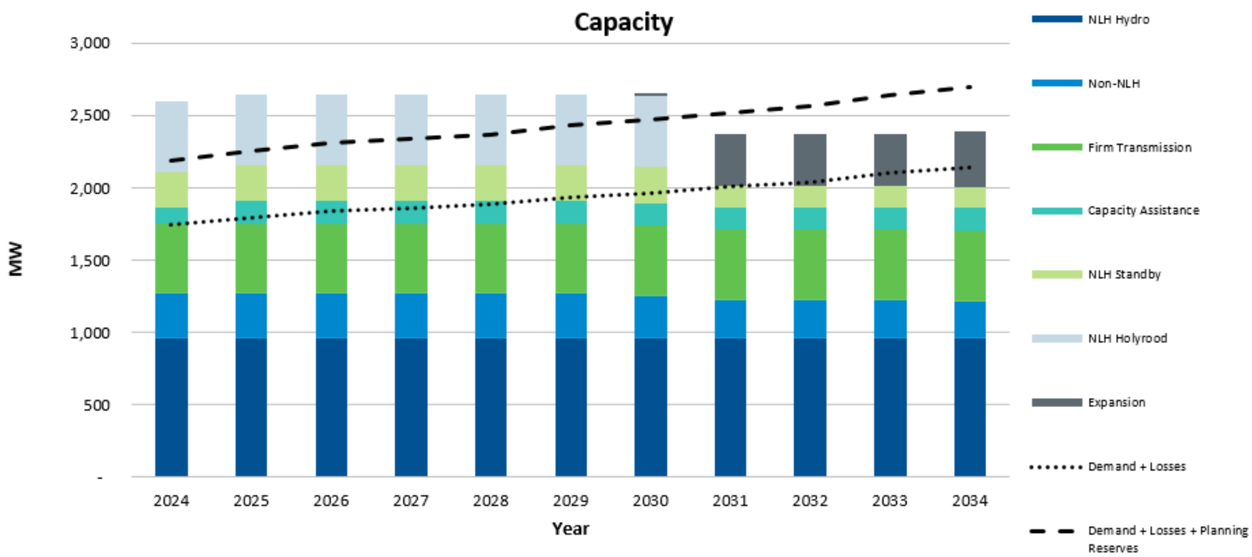


Chart 43: Capacity Load Resource Balance
(Accelerated Decarbonization Load Forecast, 5% LIL bipole EqFOR)

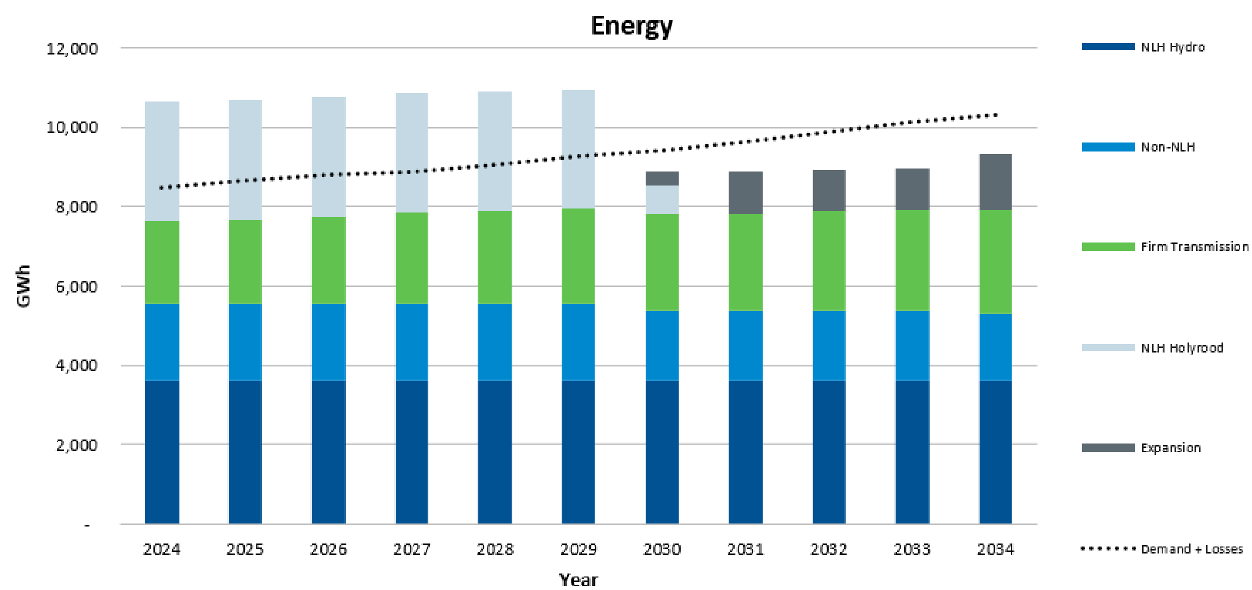


Chart 44: Energy Load Resource Balance (Accelerated Decarbonization Load Forecast)

3 Hydro recognizes that while the recommended Expansion Plan provides a balance between cost,
4 reliability and environmental impacts, it does not meet the reliability requirements should the

Reference Case load forecast materialize, or should the LIL bipole EqFOR be greater than 1%. However, the Minimum Investment Required Expansion Plan remains a significant investment in and of itself and the timing to have these new assets in place is critical to maintain the absolute minimum level of reliability of the Island Interconnected System. Hydro remains committed to continuing to assess the trajectory of future resource requirements to ensure the reliability of the Island Interconnected System through continued updates of the Resource Adequacy Plan, which could lead to additional build application requirements over and above what is recommended in the 2024 Resource Plan.

The actions required to meet the capacity, energy, and transmission requirements for the recommended Expansion Plan are discussed further in Section 9.0.

8.2 Meeting Hydro's Planning Criteria

All supply expansion analysis completed throughout the 2024 Resource Plan was conducted based on Hydro's resource planning criteria[194] in consideration of cost, reliability, and environmental responsibility. The planning criteria in relation to the key outcomes of this analysis are summarized as follows:

- **Probabilistic Capacity Criteria: The Island Interconnected System should have sufficient generating capacity to satisfy a LOLH expectation target of not more than 2.8 hours per year.**

  To meet these criteria, all scenarios identified, at a minimum, require at least one capacity resource upon the retirement of the Holyrood TGS, with the second capacity resource required within the following five years. Both capacity resources will be advanced as soon as possible to reduce the reliance on aging thermal assets, reduce the impacts of the LIL shortfall analysis, and to help with On-Avalon transmission bottlenecks that occur during a LIL bipole outage. The amount of capacity required is dependent on the load forecast scenario and LIL bipole EqFOR assumptions.

[194] For additional information on Hydro's resource planning criteria, please refer to Appendix B.

- **<u>Firm Energy Criteria:</u> The Island Interconnected System should have sufficient generating capability to supply all its firm energy requirements with firm system capability.**

  In all scenarios considered, at a minimum, new energy resources were required upon the retirement of the Holyrood TGS, with the amount of firm energy required dependent on the load forecast scenario considered.

- **LIL Shortfall Assessment: The Island Interconnected System should have sufficient generating capacity to limit the loss of load to a manageable level in the case of a LIL shortfall event.**[195]

  The shortfall analysis indicates that advancing a second capacity resource to 2031 provides a balance between mitigating the reliability impact of a prolonged LIL outage and cost. Another reason for advancing the second capacity resource as soon as possible is to reduce the reliance on aging thermal assets and support the least-cost On-Avalon transmission upgrade. A further reduction or elimination of the shortfall would require additional investment beyond those recommended in this analysis. It is therefore proposed that deliberation on additional infrastructure investments to further mitigate shortfall be deferred until decisions on Minimum Investment Requirements have been reached.

9.0 Action Plan

The action plan to meet the capacity, energy, and transmission requirements for the Minimum Investment Required Expansion Plan is summarized in Sections 9.1 though 9.3.

9.1 Action Plan to Meet Energy Requirements

To begin the process of meeting firm energy requirements identified in 2030, Hydro will issue an energy EOI for the Island Interconnected System within the next 12 months, seeking clean energy sources for power supply. The EOI is not a request for formal proposals; rather, the information developed through the EOI will be used in evaluating candidates to receive potential future RFPs for consideration for a PPA.

[195] The loss of the LIL bipole is considered a high consequence event impacting the Island Interconnected System. While it does not have specified planning criteria, planning to mitigate the consequences of a prolonged LIL outage is essential and Hydro continues to evaluate reliability implications of an extended LIL outage as part of the resource planning process.

In addition, Hydro recognizes that there could be a benefit to renewing existing energy PPAs should they continue to contribute towards least-cost supply requirements. Hydro will continue to work closely with existing independent power producers to determine options going forward.

9.2 Action Plan to Meet Transmission Requirements

9.2.1 On-Avalon Transmission

Hydro is exploring whether lower-cost steps can be taken to maximize transfer capacity through existing assets, including the implementation of an RAS and/or DLR technology as an equivalent to Option 4 transmission upgrades. An RAS would be designed to protect infrastructure following a contingency event to avoid a transmission line overload and/or abnormal voltage conditions. The thermal rating of a transmission line is typically calculated based on a series of conservative inputs to account for the worst-case weather conditions. Using real-time data, DLR technology would allow Hydro to operate a line to its full capacity based on the weather and conductor conditions at that moment in time. Hydro must evaluate these options to determine if they are technically viable for the Bay d'Espoir to Soldiers Pond transmission system. Detailed transmission analysis to understand potential limitations and costs in getting the capacity to the Avalon has been completed. DLR was installed on TL201 in March 2024 and the Avalon RAS Study is scheduled to begin in the third quarter of 2024. Once a sufficient amount of DLR data is collected and reviewed and the Avalon RAS Study is completed, Hydro will be able to confirm the extent of transmission reinforcements. However, should a transmission upgrade be required, the least-cost transmission requirement is Option 4, which includes the construction of a Western Avalon to Soldiers Pond transmission line in addition to adding DLR on TL201, TL202, TL206, TL203, with a total cost of approximately $150 million, as presented in Section 7.3. This assumes new On-Avalon generation with SC capability is constructed.

9.2.2 Labrador-Island Link

Recognizing the impact of LIL reliability on the reliability of the Island Interconnected System and Hydro's Expansion Plan, Hydro is also taking action to address issues identified through operation of the LIL early in its life cycle. The ongoing, completed, and planned work Hydro has undertaken in relation to both internal and external recommendations, as well as in making general enhancements to the LIL, demonstrates a prudent, customer-focussed approach.

Monitoring activities (e.g., weather stations, online infrastructure, patrols, external data collection, communications/reporting/review processes), will not only help Hydro employees best prepare the LIL before oncoming storms to reduce outage occurrences but will also help shorten repair duration and inform proper load considerations that will be utilized in future enhancement planning.

Replacement and upgrading of equipment (e.g., turnbuckles, extension straps, air flow spoilers, dampers, clamps, etc.) have allowed for the mitigation of effects due to climatological factors and helped prevent reliability issues stemming from phenomena exacerbated by weather events, such as galloping.

Analysis and studies (both internal and external) have also provided key information, which has informed future planning and also has helped Hydro avoid making unnecessary expenditures (e.g., tower and foundation adjustments) in sustaining the reliability of the LIL. Further studies, such as the engineering studies, restoration plan, and operational strategy review (being completed in 2024), will help Hydro understand the costs and benefits of various options to further reinforce the LIL assets and will help inform options to improve response to LIL outages to mitigate the impacts to customers.

Hydro has made considerable progress in satisfying all recommendations stemming from reporting and investigations and will continue to introduce new improvements when prudent, as it does for all system assets and in accordance with good utility practice. Further discussion of the recommendations and actions that Hydro is taking concerning LIL reliability is provided in Hydro's "Analysis of Recommendations, Mitigations and Enhancements of the Labrador-Island Link" report, filed with the Board on July 9, 2024.

9.3 Action Plan to Meet Capacity Requirements

Hydro will continue the advancement of the following two least-cost capacity resource options for FEED:

1) Bay d'Espoir Unit 8 with a capacity of 154 MW; and
2) A 150 MW CT located on the Avalon, with SC capability and the ability to run on, or be converted to using, alternate fuels.

The recommended Expansion Plan identified in Section 8.0 represents the conceptual design and options analysis that occurs early in the Front-End Planning phase of a project. While remaining Front-End Planning work would typically commence following the filing of the Expansion Plan results, time is of the essence to integrate new supply on the electrical system. Therefore, Hydro is currently executing FEED on both preferred new generation projects. This early decision to proceed was based on the urgent need for capacity solutions identified in the 2022 Update, which identified these supply solutions as the least-cost options for new capacity, further validated in the analysis provided herein. Once the FEED analysis is complete, Hydro intends to file applications for the first set of supply solutions will be made in late 2024 or early 2025. Because there is an immediate need to advance these projects, Hydro is making its best efforts to expedite their development while ensuring necessary, rigorous oversight. In addition, Hydro will continue to assess the grey market annually for short-term CT supply options to expedite the process.

Further information on the framework established to prepare for the construction of these assets is discussed in Sections 9.3.1 through 0.

9.3.1 Major Projects: Building Capability and Capacity

Due to the magnitude of investment required on the Island Interconnected System and the impacts that these substantial investments can have, a Major Projects Department has been created at Hydro to:[196]

- **Establish a Framework to Ensure the Successful Delivery of Major Projects:** Prepare Hydro for the regulatory oversight, governance, planning, and execution of Major Projects by developing the right processes, assembling a competent team, and engaging stakeholders to manage risk and maximize value.
- **Manage Individual Major Projects:** Completing Major Projects within cost, schedule, and quality targets.

Like utilities across the globe, Hydro is currently facing unique challenges as it plans the electricity system to enable government policies and changes in consumer behaviour that are driving increased electrification and load growth. Through its newly established Major Projects Department and supporting teams, Hydro will need to manage a portfolio of large projects while meeting both regulatory and public procurement requirements.

Having recently completed a Major Project—the construction of TL267—as well as the Muskrat Falls Mega Project, there are resources and processes that Hydro can use as well as many lessons learned from which Hydro and its customers would benefit. The Major Projects Department recognizes

[196] This was reflected in Commissioner Richard LeBlanc's recommendation from the Muskrat Falls Inquiry for well-defined oversight for projects with a budget of $50 million or more. Honourable Richard D. LeBlanc, "Muskrat Falls: A Misguided Project," Commission of Inquiry Respecting the Muskrat Falls Project, March 5, 2020, vol. 1, Key Recommendations, p. 61.

organizational readiness, proper governance, and decision-making are critical to successfully achieving a net-zero electricity grid.

The Major Projects Department has already taken the following actions to ensure the successful delivery of Major Projects:

- Engaged external expertise to support the development of key governance documents for Major Projects to ensure that project decisions are well-founded and well-documented. This included a review of the management of Major Projects within the electrical utility industry in Canada;
- Engaged Hydro's Internal Audit Department to create an audit plan for ongoing review of Hydro's Major Projects and processes;
- Implemented recommended actions as a result of engagement with Hydro's Internal Audit Department to review current governance of Major Projects against industry practices, such as the PMBOK Guide[197] and AACE Recommended Practices;
- Implemented recommended actions as a result of engagement with Hydro's Internal Audit Department to review early cost and schedule estimates of potential projects;
- Established an internal Executive Steering Committee and Special Board of Directors Sub-Committee specific to Major Projects initiatives;
- Developed a lessons-learned database, incorporating recommendations from the *Muskrat Falls Inquiry* as well as lessons learned from past Major Projects;
- Implemented Duty to Document processes in line with proposed amendments to the *Management of Information Act;*[198,199] and
- Initiated early engagement with major suppliers, contractors, and other utilities to understand supply issue challenges and the strategies other utilities are using to mitigate these risks.

[197] Project Management Institute, Inc. *A Guide to the Project Management Body of Knowledge (PMBOK Guide) and the Standard for Project Management,* 7th ed., Project Management Institute, Inc., Newton Square, PA, 2021.
[198] *Management of Information Act*, SNL 2005, c M-1.01.
[199] Amendments proposed under Bill 22, *An Act to amend the Management of Information Act and the House of Assembly Accountability, Integrity and Administration Act,* 2nd Session, 50th General Assembly, Newfoundland and Labrador. https://www.assembly.nl.ca/housebusiness/bills/ga50session2/bill2322.htm

The Major Projects Department has already taken the following actions to progress the new generation projects:

- Ongoing Front-End Planning, FEED, and EA activities for the Bay d'Espoir Unit 8 project, including field studies and stakeholder engagement;
- Ongoing Front-End Planning, FEED, and EA activities for the Avalon CT project, including field studies and stakeholder engagement; and
- Exploring opportunities for ECI for both the Bay d'Espoir Unit 8 and Avalon CT projects.

Initial planning is in motion, with the goal of integrating these resources swiftly. Major Projects initiatives are a corporate priority for Hydro; key deliverables have been identified per department and resources have been assigned, where required, to ensure Hydro is ready to effectively examine and present proposed investments to external relevant parties through the regulatory process and manage any approved major investment in the electrical system.

9.3.2 Major Projects Life Cycle

The project life cycle represents a series of stages a project passes through, from initiation to closure. Each phase represents distinct goals or milestones in the larger project life cycle. As a project moves through its life cycle, it becomes more defined; increasing levels of project definition and design development allow for more informed cost estimation, schedule development, and risk identification. Phases can overlap for different components of a project and deliverables mature as the project proceeds through the life cycle.

There are many ways to name and organize these stages, but construction projects typically progress through planning, execution, and closure phases. Figure 8 illustrates an example of the life cycle of a project with associated phases.

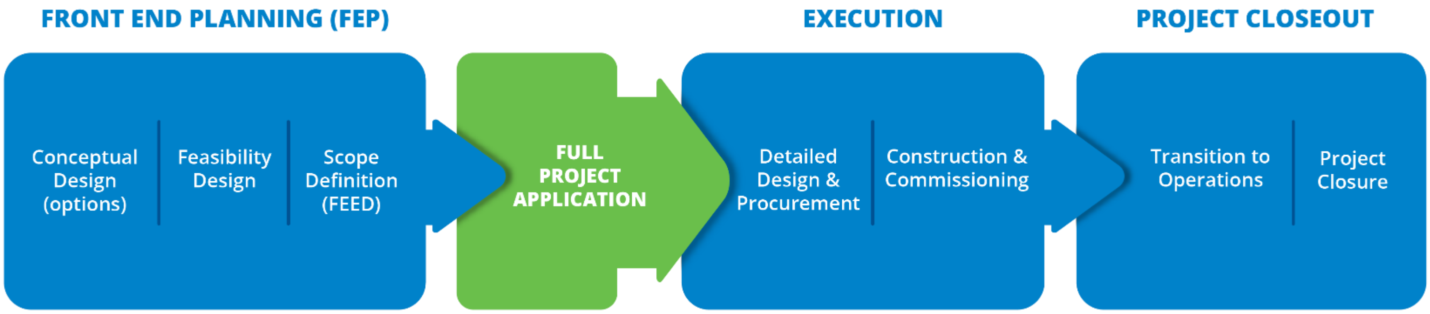


Figure 8: Project Life Cycle

A staged project life cycle approach to project delivery defines points during the life of a project when management carefully considers key information—such as project costs, schedule, scope, and risk—and assesses whether to approve proceeding to the next stage or whether to pause or terminate the project, if necessary. Hydro's current capital projects follow a similar process, with a FEED stage supporting the capital budget application followed by the execution and closeout phases for projects that proceed.

Hydro is currently reviewing processes from other Canadian utilities to develop a formal phased life cycle approach that is typical of large construction projects. The application of well-defined checkpoints, especially early in the project life cycle, provides management and relevant parties with an informed assessment of progress and issues, a validation of the project justification, and ultimately leads to better decisions on plans and investments for the future. This approach is a powerful and appropriate way to formalize project oversight.

Hydro is working with internal stakeholders to develop a draft life cycle process and is planning engagement with relevant external parties to align on the process, including key decision points and criteria for approval. Hydro's key considerations for this process are:

- External engagement, to allow informed, transparent, and efficient decision-making;
- Clearly defined criteria (cost, schedule, and project specifications) and review process for project approval;
- Consideration of decision points during the execution stage, where a commitment to build can be made or reviewed using updated cost estimates based on tender information received for major contracts; and

- Sound change management processes and decision-making during project execution, where project performance metrics, such as cost and schedule, are reviewed and communicated with relevant parties to ensure projects stay within determined risk profiles.

9.3.3 Completion of Front-End Planning

Front-End Planning is critical to the success of a project, as the ability to influence the characteristics of the project is highest at the beginning. From a cost perspective, the lowest costs associated with development and changes occur early in the project life cycle. As such, it is important that Hydro undertake the necessary Front-End Planning.

Within the context of the project life cycle illustrated, the recommended Expansion Plan identified in Section 8.0 represents the conceptual design and options analysis that occurs early in the Front-End Planning phase of a project. While remaining Front-End Planning work would typically commence following the filing of the Expansion Plan results, time is of the essence to integrate new supply on the electrical system. Therefore, Hydro is currently executing FEED on both preferred new generation projects. This early decision to proceed was based on the urgent need for capacity solutions identified in the 2022 Update, which identified these supply solutions as the least-cost options for new capacity, further validated in the analysis provided herein.

The work currently underway during the Front-End Planning phase follows industry standards, such as the PMBOK Guide and the AACE Recommended Practices. The outputs from this phase will include:

- Key execution planning documents, including the contracting plan, project execution plan, project controls plan, risk management plan, and other plans and strategy documents that will set a project up for execution success;
- Engineering deliverables that reflect the level of project definition necessary for an AACE Class 3 estimate;[200]

[200] AACE Class 3 estimate criteria as defined in the appropriate AACE International Recommended Practice.

- A cost estimate that meets the required industry standard,[201] the details of which will then be contained in a Basis of Estimate document;
- A cost estimate and contingency analysis that includes consideration for strategic and tactical risks, as well as escalation that includes the effects of inflation plus market conditions. The project budget put forward for approval will have a probability value of not less than P85,[202] which is consistent with the recommendation from Justice Leblanc from the *Muskrat Falls Inquiry*;[203]
- The new cost estimates will be reviewed against the Expansion Plan analysis to confirm that the projects remain the least-cost options for ratepayers;
- The establishment of EA registration requirements early in the Front-End Planning stage will reduce uncertainty around cost and schedule impacts associated with the EA process; and
- Continuing to look at new resource options, as required.

These outputs will inform the evidence provided with a build application submitted to the Board for approval.[204]

10.0 Ongoing Resource Planning Efforts

Consistent with good utility practice, Hydro will continue to assess load growth and asset performance on a regular basis to ensure the continued reliability of the Newfoundland and Labrador Interconnected System. Hydro will continue to make evidence-based decisions on future resources that are right for the province and customers. The solutions presented in this Resource Plan reflect the Minimum Investment Required in planning for the Island Interconnected System. The action plan requirements identified in

[201] For example, the cost estimate for the Bay d'Espoir Unit 8 Project will have a Class 3 cost estimate as defined per "AACE International Recommended Practice 69R-12: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industries," The Association for the Advancement of Cost Engineering, August 7, 2020. (AACE 69R-12).
[202] A P85 estimate is an estimate that incorporates sufficient contingency allowances such that there is an 85% likelihood that the cost estimate will not be exceeded.
[203] Honourable Richard D. LeBlanc, "Muskrat Falls: A Misguided Project," *Commission of Inquiry Respecting the Muskrat Falls Project*, March 5, 2020, vol. 1, Key Recommendations, p. 61. https://www.muskratfallsinquiry.ca/files/Volume-1-Executive-Summary-Key-Findings-and-Recommendations-FINAL.pdf
[204] Hydro intends to file applications for approval of construction of additional generation in late 2024 or early 2025.

Section 9.0 are Hydro's immediate priority to advance the regulatory process and to meet the absolute minimum reliability requirements of the Island Interconnected System.

To meet the Reference Case, or expected case, further action is required and additional expansion will likely be required. Hydro has also identified several Expansion Plan scenarios, particularly when load growth is high or LIL bipole EqFOR is on the high end of the range, where the identified capacity resource options are not adequate to meet the capacity requirements. Hydro is committed to identifying additional sources of capacity to meet these requirements. In addition to the action plan requirements identified in Section 9.0, Hydro's near-term actions include:

- **Battery ELCC:** Additional analysis is required to quantify the reliability benefit that batteries can provide. The ELCC for batteries was assumed to be 60% in this analysis with ELCC sensitivities of 40% and 80%. For the next Resource Adequacy Plan update, Hydro is committed to conducting a study to better define the battery ELCC for the Island Interconnected System.
- **Wind ELCC:** The ELCC for wind was assumed to be 22% in this analysis; however, there will likely be a reduction in the capacity contribution of wind as more is built on the system, particularly if the turbines are geographically close to each other. For the next Resource Adequacy Plan update, Hydro is committed to conducting a study to better define the ELCC of wind for the Island Interconnected System. The study will consider the potential synergies of pairing wind and batteries.
- **ECDM Programming:** Once complete, Hydro will assess the recommendations of the 2024 CDM Potential Study to develop the next multi-year plan for ECDM and incorporate into the next Resource Adequacy Plan update.
- **Incremental Capacity/Efficiency Potential from Existing Hydro Units**: The purpose of this study is to identify any opportunities to uprate units in Hydro's Island fleet to determine the feasibility of incremental capacity and/or efficiency.

Hydro has also identified several Expansion Plan scenarios, particularly when load growth is high, where the identified capacity resource options are not adequate to meet the capacity requirements. Hydro is committed to identifying additional sources of capacity to address the need should load growth continue. Long-term actions identified as part of continued resource planning include:

- **Pumped Storage Feasibility at Greenfield Sites:** The purpose of this study is to provide Hydro with information on the feasibility of pumped storage technology on greenfield sites on the Island, specifically on the Avalon.
- **Increase Capacity for Greenfield Hydro Development:** Assess alternative configurations of Island Pond, Round Pond, and Portland Creek to increase capacity from these resource options.

11.0 Conclusion

In the 2024 Resource Plan, Hydro is recommending Scenario 4AEF(ADV).1 (Minimum Investment Required) as a first step to progress planning for Scenario 1AEF (Reference Case). Advancing the second capacity resource to 2031 has a material benefit to the reliability of the Island Interconnected System in the event of a prolonged LIL bipole outage. Other reasons for advancing the second capacity resource as soon as possible is to reduce the reliance on aging thermal assets and to support the least-cost On-Avalon transmission upgrade. Lastly, if the Reference Case load forecast were to occur as Hydro anticipates, and/or the LIL bipole EqFOR is higher than 1%, both capacity options are required.

Resource Planning is an iterative process; Hydro is planning to complete the next update to its Resource Adequacy Plan in 2026. In the interim, Hydro will continue to perform analyses on the least-cost option to satisfy the Reference Case and continue to monitor load changes and resource capabilities. As the precise trajectory of load growth over the next decade is uncertain and LIL performance is still being proven, Hydro will continue pre-planning of additional expansion alternatives, should they be required. A further reduction or elimination of the shortfall would require additional investment beyond those recommended in this analysis. It is therefore proposed that deliberation on additional infrastructure investments to further mitigate shortfall be deferred until decisions on Minimum Investment Requirements have been reached.

At present, there are alternatives to satisfy the incremental load growth between the Minimum Investment Required and the Reference Case. Hydro is taking the appropriate actions to be ready to expedite additional supply should the expected case materialize.

Appendix C
Attachment 1

Appendix C, Attachment 1

Resource Cost Comparison

Daymark Energy Advisors

April 1, 2024

DAYMARK ENERGY ADVISORS

MEMORANDUM

TO: Samantha Tobin and David Goosney, Newfoundland and Labrador Hydro

FROM: Phil DiDomenico, Daymark Energy Advisors

DATE: April 1, 2024

SUBJECT: Resource Cost Comparison

BACKGROUND

As part of its 2024 Reliability and Resource Adequacy (R&RA) filing, Hydro will present an expansion plan that proposes resources which address any capacity and/or energy requirements over the modeled horizon. The cost and production characteristics of the resources that serve as options in the expansion plan differ significantly. Accordingly, it is critical that planners input accurate and consistent cost estimates into the software used to help develop the expansion plan (PLEXOS) to ensure that different resource options can be appropriately compared in the analysis.

An inherent complication in this cost estimate exercise is that energy project costs exhibit a high degree of unpredictability. For certain technology options, the potential cost uncertainty is exacerbated, such as hydroelectric projects which are highly dependent on site-specific civil conditions, or renewable energy technologies, which Newfoundland and Labrador does not have significant experience siting and deploying. Hydro has commissioned several studies to gather refined estimates for certain expansion options, which have been used to support the estimates used in the model. While these estimates provide valuable information about each of the specific technologies and/or projects being considered, to ensure a technically robust expansion plan it is also important to ensure that the estimates are adequately benchmarked against one another and are aligned with similar projects being observed across the industry. As such, Daymark reviewed Hydro's cost estimates to determine whether the capital cost and operating cost assumptions are generally consistent with industry benchmarks. Daymark's review did not entail any technical scrutiny of the estimates provided by engineering consultants.

DAYMARK ENERGY ADVISORS

APRIL 1, 2024

SUMMARY TABLE

The following table summarizes the findings of the benchmarking analysis.

Category	Cost Component	Units	Hydro Estimate	NREL ATB[2]	S&L[3]	AESO	Daymark Comments
Thermal	Capital	*$/kw*	$3,204	N/A	$2,179	$1,662	*Reasonable*[1]
	Fixed O&M	*$/kw-yr*	$20.00	N/A	$8.90	$64.42	*Reasonable*
	Variable O&M	*$/MWh*	$6.00	N/A	$7.73	$5.17	*Reasonable*
Hydro	Capital	*$/kw*	$3,345 - $19,055	$4,804 - $31,862	$9,598	N/A	*Reasonable*[4]
	Total O&M	*$/kw-yr*	$44 - $204	$44.73 - $301.90	$45.51	N/A	*Reasonable*
Wind	Capital	*$/kw*	$2,082	$2,177 - $3,132	$2,020	N/A	*Reasonable*
	Fixed O&M	*$/kw-yr*	$48.00	$46.32 - $60.70	$44.86	N/A	*Reasonable*
	Variable O&M	*$/MWh*	$0.00	N/A	N/A	N/A	*N/A*
Solar	Capital	*$/kw*	$1,659	$2,062	$2,038	N/A	*Reasonable*
	Fixed O&M	*$/kw-yr*	$26.00	$36.74	$27.45	N/A	*Reasonable*
	Variable O&M	*$/MWh*	$0.00	N/A	N/A	N/A	*N/A*
Battery	Capital	*$/kw*	$2,221 - $2,740	$2,851	$2,366	N/A	*Reasonable*
	Fixed O&M	*$/kw-yr*	$89 - $110	$38.34 - $140.57	$54.28	N/A	*Reasonable*
	Variable O&M	*$/MWh*	$0.00	N/A	N/A	N/A	*Reasonable*[5]

1. Allowing for site specific and design variations.
2. NREL ATB values were reported in 2020 USD. Adjustments were made using a conversion rate of 1 USD/1.357 CAD and a cumulative inflation rate of 17.71%.
3. S&L values were reported in 2023 USD. Adjustments assumed a conversation rate of 1 USD/1.357 CAD.
4. Costs for hydroelectric facilities are highly site-specific. Daymark expects that, given the two existing options, capital and O&M may materialize at the lower end of industry benchmarks given pre-existing infrastructure and staffing.
5. There may be cost drivers associated with battery usage within the system that Daymark recommends as an area for future review.

DAYMARK ENERGY ADVISORS

APRIL 1, 2024

METHODOLOGY

This review was performed on the expansion options that were in Hydro's model for the 2024 R&RA expansion planning process. Resource planning best practice is to ensure that the expansion module comprises all plausible resource options. This item will be discussed further in our review of the overall R&RA process.

Standard industry practice for resource comparison, which Hydro's expansion model adheres to, is to estimate the costs of resources up to the plant step-up transformer (i.e., the resource plus all balance of plant costs). Resource planning best practice is to consider the transmission cost differences associated with different resource plans. This will be discussed further in our review of the overall R&RA process.

To determine the reasonableness of Hydro's estimate, Daymark first determined, for each of the selected benchmark reports, the most appropriate reference technology for the option contained in Hydro's model. Next, Daymark considered the potential cost drivers for installations of the technology being reviewed, incorporating contextual information from the benchmark reports and industry knowledge, and reconciling this with Daymark's understanding of unique circumstances involved with deploying energy projects in the province. In cases where any cost difference between the benchmarks and the Hydro estimates can be explained by known deviations in cost drivers, on a directional and order-of-magnitude basis, Daymark considered Hydro's estimates to be reasonable.

SUMMARY OF RESOURCE ASSUMPTIONS

The table below summarizes the resource assumptions contained in the model as of February 9, 2024. For ease of comparison, the capital costs have been summed (straight line); in the model there are differences between capital commitment timelines by resource type. All costs are shown in 2023 CAD.

Category	Option Name	Rated Capacity (MW)	Capital cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)
Thermal CT	GE LM6000	142	3,204	20	6
Hydro	Portland Creek	23	15,746	119	8
Hydro	Island Pond	36	15,570	121	8
Hydro	Round Pond	18	19,055	144	8
Hydro	BDE Unit 8	154	3,345	16	8
Hydro	Cat Arm Unit 3	68	4,662	24	8
Renewable	Wind	100	2,082	48	0
Renewable	Solar	20	1,659	26	0
Battery	Battery	20	2,740	110	0
Battery	Battery	50	2,221	89	0

DAYMARK REVIEW

Sources

Daymark consulted three industry resources which provide comparisons of costs for various electricity generating technologies. Daymark's objective in consulting these resources was to determine if Hydro is using reasonable capital and operating costs in developing its expansion plans as part of the 2024 Reliability and Resource Adequacy filing.

- The National Renewable Energy Laboratory Annual Technology Baseline (NREL ATB)[2], is a survey of various electric generating technologies' costs. Daymark determined that the ATB does not contain detailed information about diverse thermal technologies and therefore discarded this source for the purposes of benchmarking thermal options.
- Sargent & Lundy's (S&L's) Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies[3] for the Energy Information Agency contains capital and operating cost estimates for a range of generic generating technologies with standard specifications.
- The Alberta Electric System Operator's (AESO's) Cost of New Entry Study[4] was referenced to provide an additional cost data point for aeroderivative combustion turbines.

Thermal Benchmarking

Summary

Hydro's expansion module contains one thermal expansion option, a GE LM6000 combustion turbine of 142 MW capacity. Daymark benchmarked the assumptions of this resource against the S&L and AESO publications.

Daymark used Case 3, which represents a simple cycle, four aeroderivative turbine arrangement, of 211 MW net capacity, as a reference for benchmarking Hydro's expansion option. The S&L estimate assumes a gas-fired unit with dual-fuel capability; therefore, Daymark would expect that Hydro's realized costs may be higher than this industry reference.

The AESO study considers an aeroderivative combustion turbine of the model GE LM6000-PF SPRINT with an annual average capacity of 87 MW.

Capital Costs

Hydro estimates its capital costs for the thermal expansion option at $3,204/kW.

[2] https://atb.nrel.gov/electricity/2023/index
[3] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf
[4] https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf

The capital cost estimate for the simple cycle turbine arrangement in the S&L report is $2,180/kW.

The capital cost estimate for the aeroderivative CT option in the AESO report is $1,663/kW[5].

Hydro performed a comparison of the AESO cost estimate versus the one used in the Expansion Model and identified several inconsistencies in what was included in Hydro's versus the AESO cost comparison. Removing inconsistent items resulted in Hydro's cost estimate reducing to $2,382/kW for an LM6000 which Daymark finds to be reasonable. Daymark notes that while higher than the benchmarked sources, Hydro identifies the following site-specific factors to be contributing to this discrepancy:

- Sync condenser capabilities,
- Fuel flexibility, and
- Terminal station assumptions, which may be larger than the benchmark references.

Fixed O&M Costs
Hydro estimates its fixed O&M costs for the thermal expansion option at $20/kW-year.

The fixed O&M cost estimate for the simple cycle turbine arrangement in the S&L report is $9/kW-year.

The fixed O&M cost estimate for the aeroderivative CT option in the AESO report is $64/kW-year[6].

Daymark finds Hydro's use of $20/kW-year to be reasonable given the oil-fueled and flex-fueled nature of this application.

Variable O&M Costs
Hydro estimates its variable O&M costs for the thermal expansion option at $6/MWh.

The variable O&M cost estimate for the simple cycle turbine arrangement in the S&L report is $7.73/MWh.

The variable O&M cost estimate for the aeroderivative CT option in the AESO report is $5.17/MWh[7].

Daymark finds Hydro's use of $6/MWh to be reasonable.

Hydroelectric Benchmarking

Summary

Hydro's expansion alternatives include five distinct, site-specific hydroelectric resources. There are three smaller, new-build resources at Portland Creek, Island Pond, and Round Pond, with capacity ratings of 23

[5] Value escalated from 2021 CAD to 2023 CAD by pulling forward the rates assumed in Section IV.C of the AESO report.
[6] Value escalated from 2021 CAD to 2023 CAD by pulling forward the rates assumed in Section IV.C of the AESO report.
[7] Value escalated from 2021 CAD to 2023 CAD by pulling forward the rates assumed in Section IV.C of the AESO report.

MW, 36 MW, and 18 MW, respectively, as well as two larger unit additions at existing sites, Bay D'Espoir Unit 8 (BDE 8) and Cat Arm Unit 3, with capacity ratings 154 MW and 68 MW, respectively. Daymark benchmarked these hydroelectric expansion options against the ATB and the S&L report.

Capital Costs

Hydro's estimates for the capital costs of its hydroelectric expansion options are $15,746/kW, $15,570/kW, and $19,055/kW for Portland Creek, Island Pond, and Round Pond, respectively, and $3,345/kW and $4,662/kW for BDE8 and Cat Arm Unit 3, respectively.

The capital cost range contained in the ATB is from $4,805/kW to $31,862/kW.

The capital cost estimate for the 100 MW hypothetical hydroelectric resource in the S&L report is $9,598/kW.

Costs of hydroelectric facilities are highly site-specific. As a result Daymark expected to observe a wide range of cost estimates when comparing generic estimates to site specific estimates. Further, given the two existing site expansion options, Bay D'Espoir and Cat Arm, the capital and O&M costs may be reasonably expected to be near the lower end of industry benchmarks given the existing infrastructure and staffing. Daymark therefore finds the capital cost estimates for all five expansion options to be reasonable.

However, it is worth considering a sensitivity with regards to capital costs. The capital costs for the two larger hydroelectric options were low in comparison to both benchmarks. While Daymark acknowledges that there is a high degree of site-specificity, especially given that these are existing projects, Daymark urges Hydro to consider substantially higher estimate for this parameter to better understand the sensitivity of the expansion plan to these cost estimates. This should potentially include any transmission solutions required to make either of the large hydro expansions viable.

Fixed O&M Costs

Hydro's estimates for the fixed O&M costs of its hydroelectric expansion options are $119/kW-year, $121/kW-year, and $144/kW-year for Portland Creek, Island Pond, and Round Pond, respectively, and $16/kW-year and $24/kW for BDE8 and Cat Arm Unit 3, respectively.

Both industry benchmarks consulted chose not to represent variable O&M costs. To allow for comparison, Hydro converted its variable O&M costs to fixed O&M costs which results in overall fixed costs of $168/kW-year, $162/kW-year, and $204/kW-year for Portland Creek, Island Pond, and Round Pond, respectively, and $44/kW-year and $54/kW for BDE8 and Cat Arm Unit 3, respectively.

The fixed O&M cost range contained in the ATB is from $45/kW-year to $302/kW-year.

The fixed O&M cost estimate for the 100 MW hypothetical hydroelectric resource in the S&L report is $46/kW-year.

Taking into consideration the small size of the three new build options and the economies of scale at the existing sites, Daymark finds the fixed O&M cost estimates for all five expansion options to be reasonable.

Variable O&M Costs
The industry benchmarks consulted did not represent costs as driven by energy production of the hydroelectric facilities. To ensure the reasonableness of Hydro's overall expansion options, the variable O&M costs have been rolled into the fixed O&M estimates for the sake of comparison as noted above.

Wind Benchmarking

Summary
Hydro's expansion alternatives include a 100 MW land-based wind option. Daymark benchmarked the assumptions for this expansion option against the ATB and S&L's report.

Capital Costs
Hydro's estimate for the capital cost of the wind expansion option is $2,082/kW.

The capital cost estimate for the "Technology 1"[8] configuration in the ATB report ranges from $2,177/kW to $3,132/kW.

The capital cost estimate for the hypothetical configuration in the S&L report is $2,021/kW.

Daymark finds Hydro's capital cost estimate for the wind expansion option to be reasonable.

Fixed O&M Costs
Hydro's estimate for the fixed O&M cost of the wind expansion option is $48/kW-year.

The fixed O&M cost estimate for the "Technology 1" configuration in the ATB report ranges from $46/kW-year to $61/kW-year.

The fixed O&M cost estimate for the hypothetical configuration in the S&L report is $45/kW-year.

Daymark finds Hydro's fixed O&M cost estimate for the land-based wind expansion option to be reasonable.

[8] Technology 1 reflects 34 turbines of 6 MW capacity each composing a 200MW site. Technology 1 is intended to provide an indicative configuration for higher-wind-speed sites. The individual turbine sizes are greater than those widely in application for on-shore wind designs today but are appropriate for expansion planning as they incorporate forward-looking industry trends.

Variable O&M Costs
Not applicable.

Solar Benchmarking

Summary
Hydro's expansion alternatives include a 20 MW nameplate solar photovoltaic expansion option. Daymark benchmarked the assumptions for this expansion option against the ATB and S&L's report. S&L's report considers a hypothetical 150 MW_{AC} solar photovoltaic installation.

Capital Costs
Hydro's estimate for the capital cost of the solar expansion option is $1,659/kW.

The capital cost estimate for utility scale solar installations in the ATB is $2,062/kW.

The capital cost estimate for the hypothetical configuration in the S&L report is $2,038/kW.

Daymark finds Hydro's capital cost estimate for the solar expansion option to be reasonable.

Fixed O&M Costs
Hydro's estimate for the fixed O&M cost of the solar expansion option is $26/kW-year.

The fixed O&M cost estimate for utility scale solar installations in the ATB is $37/kW-year.

The fixed O&M cost estimate for the hypothetical configuration in the S&L report is $28/kW-year.

Daymark finds Hydro's fixed O&M cost estimate for the solar expansion option to be reasonable.

Variable O&M Costs
Not applicable.

Battery Energy Storage Benchmarking

Summary
Hydro's expansion alternatives include two battery energy storage options, a 20 MW and a 50 MW nameplate capacity installation. Both resources are 4-hour duration batteries. Daymark benchmarked the assumptions for these expansion options against the ATB and S&L's report.

Capital Costs
Hydro's estimates for the capital costs of the battery energy storage expansion options are $2,740/kW and $2,221/kW for the 20 MW and 50 MW configurations, respectively.

The capital cost estimate for a 60 MW_{DC}, 4-hour battery in the ATB is $2,851/kW.

The capital cost estimate for the 150MW_{AC}, 4-hour battery in the S&L report is $2,366/kW.

Daymark finds Hydro's capital cost estimate for the battery storage options to be reasonable.

Fixed O&M Costs
Hydro's estimates for the fixed O&M costs of the battery energy storage expansion options are $110/kW-year and $89/kW-year for the 20 MW and 50 MW configurations, respectively.

The fixed O&M cost estimate for a 60 MW_{DC}, 4-hour battery in the ATB ranges from $62/kW-year to $120/kW-year.

The fixed O&M cost estimate for the 150MW_{AC}, 4-hour battery in the S&L report is $54/kW-year. This estimate of O&M costs assumes some battery augmentation to accommodate deterioration effects but assumes no major equipment replacement and instead assumes a service life of ten years.

Daymark finds Hydro's fixed O&M cost estimate for the battery expansion options to be reasonable. Daymark notes that the O&M costs of battery installations in particular exhibit a high degree of dependence on usage, intended service life, and performance requirements, and therefore recommends this as an area for continued focus for Hydro in its modeling efforts as the industry gains more familiarity with the technology.

Variable O&M Costs
Hydro's model and the industry benchmarks do not contain variable O&M cost estimates for the battery expansion options. However, as noted above, we expect that there may be cost drivers associated with battery usage within the system that we recommend as an area for future review.

CONCLUSION

The capital cost, fixed O&M costs, and variable O&M costs that Hydro uses as a basis for its expansion planning activities are reasonable in comparison to industry benchmarks.

Daymark in performing its review also noted that two of the expansion technologies, the combustion turbine and the battery energy storage systems, have O&M costs that are dependent on how the resource is used in the system. Daymark considers the assumptions Hydro has used in this filing for the O&M costs for these technologies to be reasonable but suggests that Hydro review the modeling treatment of these resources in future iterations of the expansion plan.

Daymark has the following recommendations to ensure that technologies are compared to one another as accurately as possible:

- The capital costs for the two larger hydroelectric options were low in comparison to both benchmarks. While Daymark acknowledges that there is a high degree of site-specificity, especially given that these are existing projects, Daymark urges Hydro to consider substantially higher estimate for this parameter to better understand the sensitivity of the expansion plan to these cost estimates.

- The capital cost for the CT was high in comparison to industry benchmarks. Daymark recommends that Hydro considers ensuring that all cost estimates carry the same level of design estimates. Overly burdening one supply resource may tend to skew results leading to a sub-optimal expansion plan. Hydro has confirmed that the capital costs will be refined for any future build applications.

Appendix C
Attachment 2

Appendix C, Attachment 2

Uprate Report

Hatch Ltd.

June 27, 2024

NL Hydro	Engineering Report
BDE Unit # 7 Condition Assessment	Engineering Management
H371822	Uprate Report

Report

Uprate Report

H371822-0000-2A1-066-0002

2024-06-27	0	Approved for Use	F. Welt	D. Flores/ M. Slijepcevic	D. Flores
Date	**Rev.**	**Status**	**Prepared By**	**Checked By**	**Approved By**

Disclaimer

This report has been prepared by Hatch Ltd. (Hatch) for the sole and exclusive use of NewFoundland Hydro Inc. (the "Owner") for the purpose of assisting the management of the Owner to determine the feasibility of making decisions with respect to the Bay D'Espoir Unit # 7 Level II Condition Assessment (the "Project") and must not be provided to, relied upon or used by any other party. The use of this report by the Owner is subject to the terms of the relevant services agreement between Hatch and Owner.

This report is meant to be read as a whole, and sections should not be read or relied upon out of context. The report includes information provided by the Owner and by certain other parties on behalf of the Owner. Unless specifically stated otherwise, Hatch has not verified such information and does not accept any responsibility or liability in connection with such information.

This report contains the expression of the opinion of Hatch using its professional judgment and reasonable care, based upon information available at the time of preparation. The quality of the information, conclusions and estimates contained in this report is consistent with the intended level of accuracy as set out in this report, as well as the circumstances and constraints under which this report was prepared.

As this report is an Uprate Condition study, all estimates and projections contained in this report are based on limited and incomplete data. Accordingly, while the work, results, estimates and projections in this report may be considered to be generally indicative of the nature and quality of the Project, they are not definitive. No representations or predictions are intended as to become the results of future work, and Hatch does not promise that the estimates and projections in this report will be sustained in future work.

Table of Contents

Disclaimer i

1. Executive Summary 1

2. Introduction 1

2.1 Study Objectives 1
2.2 Review of Available Information 2
2.2.1 Description 2
2.2.2 Limitations of Past GE Hydro and American Hydro Reports 2

3. Scenario Definition 3

3.1 Upgrade Considerations 3
3.1.1 Turbine 3
3.1.2 Generator 5
3.1.3 Power Train 6
3.1.4 Consideration for Bay D'Espoir Unit # 8 6
3.2 Scenario Definition Summary 6

4. Methodology 7

4.1 Unit Uprate Capital Costs 7
4.2 Risk Profile 7

5. Cost Evaluation Outputs 8

5.1 Annual Cost Streams and intervention Schedule 8
5.2 Expected Number of Failures 8

6. Conclusions 9

7. Recommendations 9

List of Tables

Table 1-1: Capital Costs for Each Scenario 1
Table 3-1: Upgrade Options 6
Table 5-1: Number of Expected Failures over Next 25 Years 9

List of Figures

Figure 3-1: U7 Historical Power Distribution – Year 2008 to 2020 4
Figure 3-2: Tailwater Elevation Characteristics 5
Figure 3-3: Efficiency Characteristics for the Various Runner Upgrade Options 7
Figure 5-1: CAPEX Plan for the Upgrade Option with a Higher Efficiency and Higher Capacity Unit 8

List of Appendices

Appendix A: Additional Information

A.1 Cost Calibration

List of Abbreviations

BDE	Bay D'Espoir Hydro Plant
CAPEX	Sustained Capital Expenditures
CB	Circuit Breaker
CFD	Computational Fluid Dynamic
CT	Current Transformer
^{o}C	Degree Celsius
GVO	Gate Vane Opening
MVA	Mega Volt Amp
MW	Megawatt
MWh	Megawatt Hour
NLH	Newfoundland and Labrador Hydro
OEM	Original Equipment Manufacturer
PF	Power Factor
RTDs	Resistance Temperature Detectors
U7	Bay D'Espoir Unit # 7

1. Executive Summary

Various uprate options for Unit # 7 at the Bay D'Espoir hydro plant were investigated for their feasibility based on a review of available information, and their associated capital costs were estimated.

Overall, upgrading Unit # 7 to a larger capacity of 174MW for an overall investment in the range of CAD$ 19M to 28M, including runner replacement and generator rehabilitation with stator and rotor rewind as well as other modifications, should be quite feasible. Upgrading to an even larger capacity of 180 MW should also be possible within the existing water passage and embedded components, however further analysis would be required to confirm its feasibility.

An economic evaluation was conducted for the main uprate options, and the results for what can be considered as the investments required for the upgrade are shown in Table 1-1.

Table 1-1: Capital Costs for Each Scenario

Scenario	Option	Capital Cost (K$)	Comments
1	Upgrade: 2% Efficiency Increase	18,750	Recommending changing the runner as soon as possible to benefit from gains in efficiency.
2	Upgrade: Capacity Increase	19,350 – 27,910	Expressed as a range as additional capital investment may be required to accommodate larger capacity based on future analysis.

Most of the investments required for the uprate would be similar to those required to maintain operation on the current equipment, as per Hatch's latest condition assessment, including runner replacement and generator rewind. However, additional investments to accommodate the larger capacity may have to be made based on future analysis, such as changes to the gate servo motor assembly, generator cooling system or step-up transformer, which would bring the overall investment closer to the upper range indicated above.

2. Introduction

2.1 Study Objectives

NLH have identified the need for increased on-island generation capacity through the Resource and Reliability Adequacy Study and its associated updates. One method identified by NLH to increase generation capacity is through the uprating of existing generating assets. NLH have selected BDE Unit #7 as the first to be investigated for uprating potential because this unit will require an overhaul in the near future due to its age and condition.

The objective of this study was to provide additional insight into the feasibility of a future capacity increase for BDE Unit # 7 based on a review of previous upgrade studies conducted for NLH. Particular attention was given to the studies conducted by GE Hydro in 2002 and American Hydro in 2020, while taking into consideration the fact that the GE report appears to be based on significantly more analysis than the American Hydro Report.

This present study assumed that the existing water flow at headrace level at rated output are maintained, major embedded parts such as scroll case and draft tube are not replaced and the new equipment requires no modifications to concrete and other powerhouse structures including the overhead crane.

2.2 Review of Available Information

2.2.1 Description

There was a variety of information provided by NLH on the unit historical operations, maintenance records, project drawings, manuals and procedures, asset data, prior condition assessments and uprate studies. All this information was reviewed and assessed in some detail based on the objective of the current uprate study.

The information on the plant and unit flows, hydraulic head, operating data for the various equipment, was provided by NLH upon request as the result of the on-site technical assessment.

The uprate reports on the BDE Unit # 7 runner replacement by GE Hydro (2004) and American Hydro (2020) were reviewed for information on the capital costs for runner replacement and the resulting performance benefits in terms of increased capacity, enhanced efficiency, and improved cavitation resistance.

The information provided by NLH on total costs for various historical refurbishment and upgrade projects for the key turbine and generator components was also considered to determine the costs for the different replacement and repair options considered in this study.

2.2.2 Limitations of Past GE Hydro and American Hydro Reports

2.2.2.1 GE Hydro Report (2004)

It should be noted that the GE Hydro and American Hydro reports did not fully analyze the viability of the upgrades. GE Hydro’s report analyzed a number of critical factors related to the unit upgrade including Computational Fluid Dynamics (CFD) and transient analyses. GE Hydro was confident that the runaway speed and hydraulic thrust of an uprated runner would not be an issue. More current state of the art methods and tools could be used by other OEMs to confirm this assessment. GE Hydro also commented on the generator capabilities. However, complete electromagnetic calculations would be required to confirm the generator capacity with stator and rotor modifications.

A brief review of the cost estimate provided by GE and escalated to 2023 CAD using the Engineering News Record – Construction Cost Index, appears to be much lower than anticipated by Hatch. To get a more accurate estimate, budgetary quotes from various OEMs are recommended.

2.2.2.2 American Hydro Report (2020)

American Hydro's report focused more narrowly on the runner uprate without as much supporting analysis as the GE Hydro report. American Hydro was confident in a 10% uprate in capacity, i.e., at a potential power of 174 MW, with a 1-3% efficiency gain. However, the American Hydro performance curve shows a lower efficiency compared to current design at outputs between 40 and 140 MW. American Hydro reported that a larger power increase would require modifications to the discharge ring and draft tube. Hatch is skeptical that these modifications are necessary but further studies would be required to make a definite determination.

3. Scenario Definition

3.1 Upgrade Considerations

The upgrade under consideration includes potential runner and generator upgrade options, including both efficiency improvements and output capacity increases, which may have an additional capital cost while potentially providing additional revenues for the facility.

It should be noted that no alterations to the hydraulic design were considered, thus excluding any changes to the tailwater elevation and associated unit head.

3.1.1 Turbine

When analyzing the runner capacity increase from 150 to 180 MW, attention should be given to the turbine efficiency in the operating range between 70 and 150 MW where the unit has been historically most frequently used based on available information, as illustrated in Figure 3-1 which shows utilization as a percentage of maximum power of 155 MW. If efficiency at typical operating conditions is sacrificed to provide a capacity uprate, the value of the turbine uprate is diminished. From the GE Hydro Report, the efficiency of the proposed runner is lower than the original design up to 150 MW.

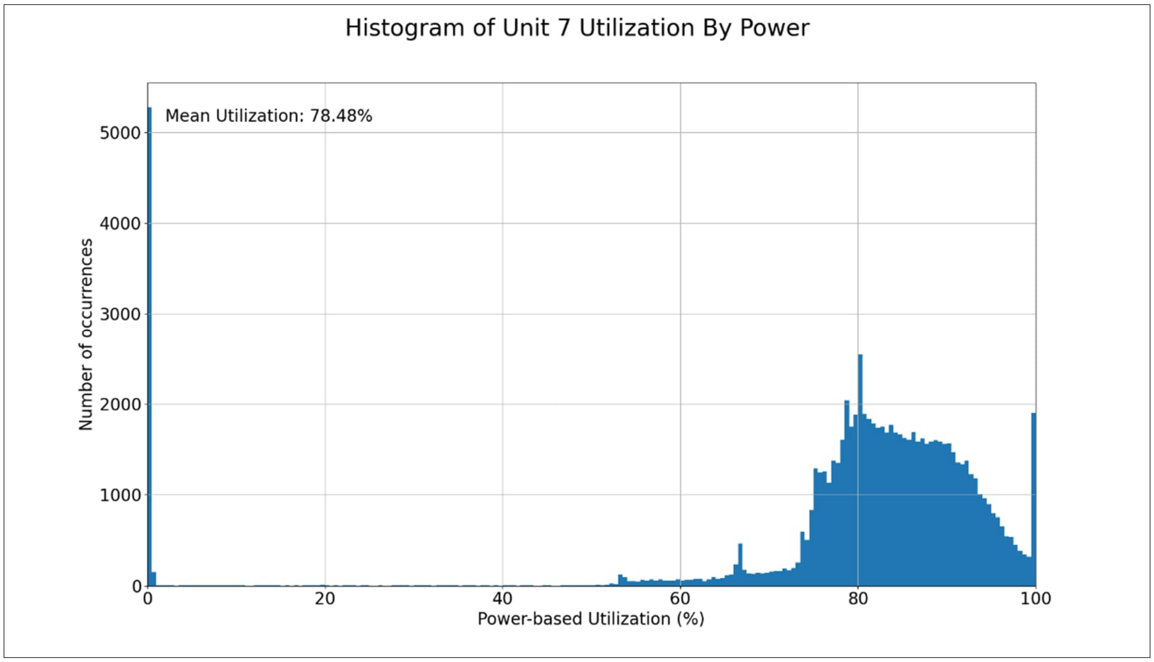
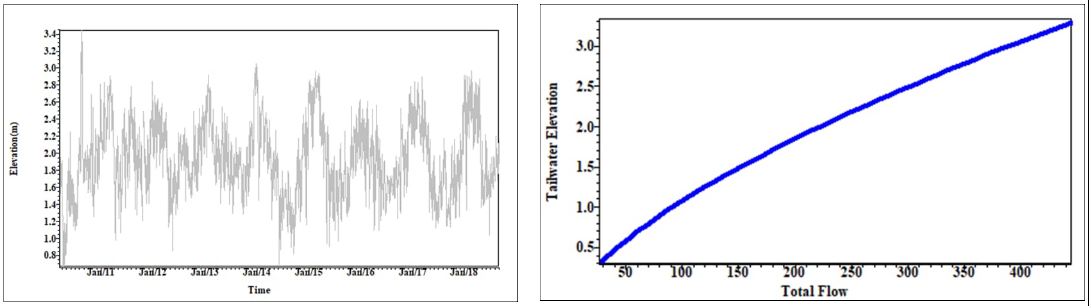


Figure 3-1: U7 Historical Power Distribution – Year 2008 to 2020

Also, confirmation of maximum power and best efficiency power Gate Vane Opening (GVO) should be considered. Asset data files shows that there is additional capacity that can be accommodated by the gate vane opening (unit power of 139.55MW with GVO of 77.4%).

Another consideration when upgrading the runner output is the tailwater elevation. Based on the GE Hydro Report, the ability to generate power up to or exceeding 180 MW relies on the sufficiently large tailwater elevation required for cavitation protection, i.e., where only 170 MW can be supported at an elevation of 0.8 m or higher, and 180 MW requires an elevation of 2.2 m or higher.

Note that based on operational data available to Hatch between year 2010 and 2018, the tailwater elevation generally varies between 1.0 and 2.8 m, with an overall average around 2.0 m. It is also flow dependent and would be higher when the turbine is operated at high capacity (Figure 3-2). Therefore, turbine outputs of 180 MW are expected to be operated within the proper elevation range and should be very feasible based on the available information, and without impacting the reliability of the unit under the assumptions that the appropriate modifications are made.



Recorded Tailwater Elevation Year 200-2018

Tailwater Rating Curve

Figure 3-2: Tailwater Elevation Characteristics

GE Hydro and American Hydro employed different design approaches, where each approach required modifications to the turbine to support the uprated capacity. GE Hydro required increasing the wicket gate opening and the gate servomotor closing time. American Hydro stated that excavation and replacement of the discharge ring and upper section of the draft tube would be required. Hatch has not confirmed if either the GE Hydro or American Hydro modifications are required but would anticipate that modifications to the gate operating mechanism would be necessary to increase the gate opening. Other modifications are likely, but Hatch has not fully analyzed to what extent those modifications would be required.

3.1.2 Generator

GE Hydro Report considered the maximum output of the generator at 185 MW, and 188 MW for the runner, in order not to exceed the power that can be taken by the modified generator. Hatch assumes that the generator is therefore capable of the proposed uprate to 180 MW. However, an electromagnetic, mechanical and vibration calculation would be required to ensure the generator is capable of the power uprate.

When analyzing the operating data provided for the months of January and August 2023, it was noticed that the total operating temperature of the stator as recorded by the embedded RTDs are approximately 30ºC below the recommended total operating temperature of 100ºC, confirming that the existing generator is very efficiently ventilated at the existing rating. A calculation of the total operating temperature for the stator used under a new uprated runner capacity of 180 MW shows that it would still operate with a margin of 25ºC below the recommended temperature. It also shows that keeping the total operating temperature unchanged under the new capacity would call for the replacement of the stator windings. This indicates that there is an opportunity for increasing the copper content per bar turn during a stator winding replacement, which would deliver lower stator winding resistive losses (I^2R). There is also an opportunity to lower the no-load stator core losses with a stator core replacement utilizing modern non-oriented magnetic steel.

GE Hydro recommended to replace the rotor floating rim design. Hatch has not confirmed the necessity of this intervention, but planning for a new or modified rotor, in addition to rewinding the stator, is advised to achieve an uprate in the range of 180 MW.

3.1.3 *Power Train*

The American Hydro Report stated that the current step-up transformer capacity should be 190 MVA at 0.9 PF for a potential maximum runner power output of 174 MW. When uprating the turbine, Hatch recommends that the capacity of the full power train be analyzed, and an additional scope would be required to replace the transformers and other possible upgrades to the power train.

3.1.4 *Consideration for Bay D'Espoir Unit # 8*

It should be noted that Hatch analyzed the Unit # 7 uprate independently of other possible capacity changes at the Bay D'Espoir facility, more specifically regarding the potential addition of Unit # 8. Since there is a finite amount of hydraulic capacity available in the Bay D'Espoir system to be utilized for the purposes of additional generating capacity, it may be more cost-effective to utilize that hydraulic capacity in a new purpose-built Unit # 8 rather than through a modification of Unit # 7. It would also change the typical tailwater elevations, and an analysis of an uprate to Unit # 7 given a new unit is recommended. Following such an analysis, the economics of a larger new unit may prove to be a better value to NL Hydro than a capacity increase to Unit # 7.

3.2 Scenario Definition Summary

A description of the various scenarios including the various runner upgrade options is described in Table 3-1.

Table 3-1: Upgrade Options

Scenario	Options	Description	Comments
1	Efficiency improvements only	A runner efficiency increase of 2% was assumed across the operating range.	Modern runners can typically provide 2-3% increase over older designs.
2	Efficiency improvements and capacity Increase	Utilizing additional hydraulic capacity available in the system to achieve more significant increases in generating capacity than would be possible through efficiency improvements alone.	Assumes no changes to hydraulic passage and electrical system. Capacity of 180 MW was assumed, based on 2004 report by American Hydro.
3	Replace-in-Place	Minor interventions, rehabilitation or like to like replacement.	No significant performance improvements in generation outputs.

The difference in turbine efficiency between the various options is illustrated in Figure 3-3 below.

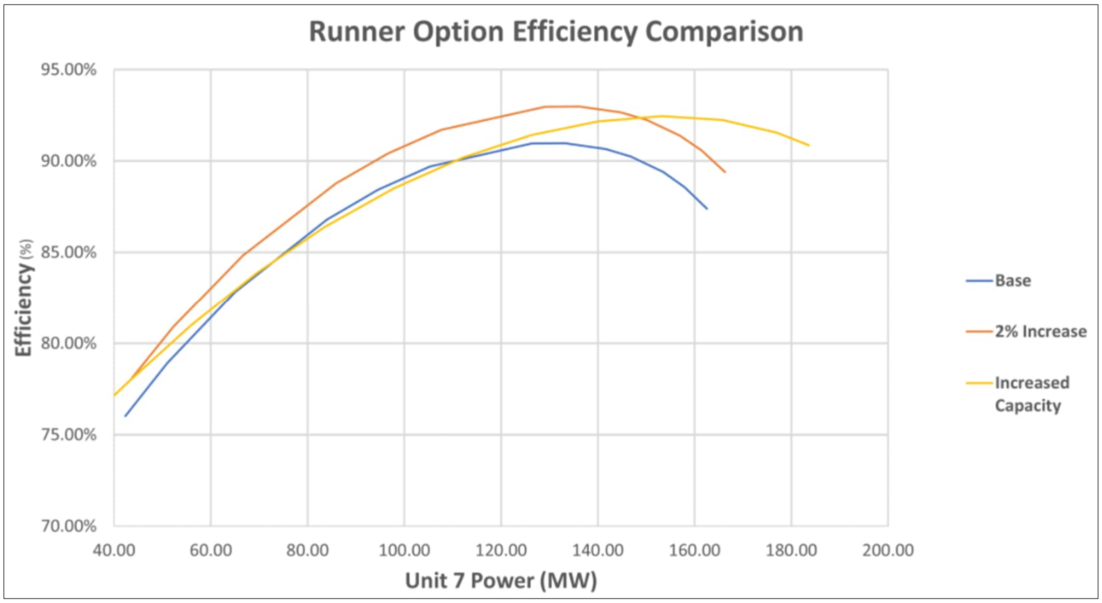


Figure 3-3: Efficiency Characteristics for the Various Runner Upgrade Options

4. Methodology

4.1 Unit Uprate Capital Costs

Capital costs were obtained from a number of sources including:

- Model calculation as a function of asset characteristics, such as size, weight, power, etc., as a function of the asset type.
- Data from uprate report provided by American Hydro, with costs re-adjusted for inflation from current conditions.
- From sample client data, used to provide a scaling factor that can be applied to the various capital expenditures considered for the uprate.

As a result of the analysis, capital expenditures were calibrated from Hatch's model benchmark values according to a scaling factor of 1.73.

This is documented in Appendix A.1. It should be noted that no losses of energy revenues due to downtime are included in the capital cost values used throughout this report.

4.2 Risk Profile

As a by-product of the model calculation, a forecast of the number of failures over the next 50 years for the major subcomponent was provided.

5. Cost Evaluation Outputs

Table results show that Scenario 1 (Efficiency Upgrade) and Scenario 3 (Replace-in-Place) options require the same amount and type of capital investments.

Table results also show that Scenario 2 (Efficiency and Capacity Increase upgrade) has a marginally to moderately higher capital costs, to be further refined pending further analysis.

5.1 Annual Cost Streams and intervention Schedule

A Planning Schedule summary for the Higher Efficiency and Capacity option (Scenario 2) is shown in Figure 5-1.

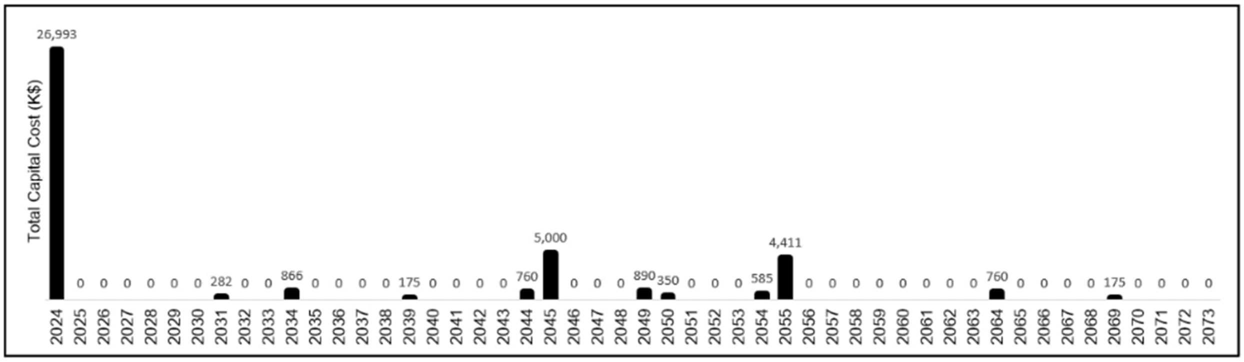


Figure 5-1: CAPEX Plan for the Upgrade Option with a Higher Efficiency and Higher Capacity Unit

5.2 Expected Number of Failures

Using the failure probability curve, the expected number of failures over the period can be extracted from the model. This is illustrated in Table 5-1 below for the major components, estimated over the first half of the study period (25 years).

Table 5-1: Number of Expected Failures over Next 25 Years

	Do-Nothing	Replace-In-Place
Stator Iron Core	2.1	0.11
Stator Winding	41.5	1.4
Generator Thrust Bearing	2.6	0.88
Runner	2.8	0.38
Pressure Relief Valve	2.6	0.00
Governor	2.6	0.61

6. Conclusions

A capacity increase of up to 174 MW, as suggested by the 2022 American Hydro report, requiring only a runner and wicket gate servo motor upgrade is deemed to be feasible without additional investment in electrical equipment or additional work on hydraulic structures, according to Hatch's preliminary analysis based on review of specifications and on-site inspection. Extending beyond such a capacity to 180 MW and higher is achievable but should require additional analysis to determine if an upgrade of the step-up transformer and power train major components is also needed. It should be noted that the 180 MW uprate option considered in the uprate report recommends upgrading both the generator and the runner concurrently, and this integrates both the impact on costs and efficiency range. Further analysis on the generator would therefore be part of the new design. However, the step-up transformer or other major components of the power train suitability were not part of the scope of this analysis.

Overall, upgrading Unit # 7 to a larger capacity of 174MW for an overall capital cost investment in the range of CAD$ 19 to 28M should be quite feasible. A potential upgrade up to 180MW can be considered but further study would be required to confirm its feasibility.

7. Recommendations

The uprate analysis for Unit # 7 should ultimately be made in combination with the addition of Unit # 8, where both units should be considered concurrently for the determination of their respective optimal capacity and design. In addition, the following analyses would be required:

- A more accurate cost estimate for the various uprate options requiring further consultation with the OEMs.
- Further analysis on the step-up transformer, Current Transformers (CT), Circuit Breakers (CB) and existing excitation system.
- Further analysis on the discharge ring and draft tube.
- Further analysis of electromagnetic and mechanical calculation to requalify major generator components of Unit # 7 acceptability at uprate level of 180 MW.

- A review of the status on Unit # 8 future design would be required in conjunction with the Unit # 7 uprate study, including:
  - Effect of both unit capacities on the tailrace elevation, and impact on the downstream tailrace structures.
- A hydrological study to determine the most desirable current and future BDE plant capacity, as well as the most efficient unit configuration from an overall BDE plant efficiency perspective given the plant utilization.

Appendix A: Additional Information

A.1 Cost Calibration

Failure and intervention costs were calibrated based on historical information obtained from NLH, as shown in Table A-5. The 2004 proposal to replace the runner at a cost of $3,038 was also included for comparison. It should be noted that model costs do not include revenue losses due to downtime for the installation, project, engineering costs and taxes. Model costs were also converted from US$ to CAN$.

Table A-1: Intervention Cost Calibration

Intervention	NLH Cost (CANK$)	Others	Model Cost (CANK$)	Scale
U1 Stator Rewind	4,532		3,325	1.36
U5 Stator Rewind	3,750		3,325	1.12
BDE U3 Discharge Ring Machining	1,545		684	2.25
Runner Upgrade*		3,038	1,400	2.18
Average**				1.73

*From American Hydro uprate report in 2004, with model prices adjusted to year 2004.

**Information on past HLK rotor and U7 turbine refurbishments was not included in the above table as there were too many items involved in the process to make a direct comparison with the model derived costs.

Appendix C, Attachment 3

Accelerated Holyrood Combustion Turbine Installation Options Study – Final Report

Stantec Consulting Ltd.

May 13, 2024

Stantec

Accelerated Holyrood Combustion Turbine Installation Options Study

Final Report

May 16, 2024

Prepared for:
Newfoundland & Labrador Hydro

Prepared by:
Stantec

Project No. 133549662

Revision	Description	Author		Quality Check		Independent Review	
A	Draft	M. Richard		R. Grey		G. Oliver	
B	Client Review	M. Richard		R. Grey		G. Oliver	
C	Final	M. Richard		R. Grey		G. Oliver	
D	Final	M. Richard		R. Grey		G. Oliver	
0	Issued to Client	M. Richard		R. Grey		G. Oliver	

Beaulieu, Norm Digitally signed by Beaulieu, Norm Date: 2024.05.16 11:31:07 -03'00'

Prepared by ______________________________
(signature)

Norm Beaulieu

Richard, Mike Digitally signed by Richard, Mike DN: CN="Richard, Mike", OU=Internal, OU=users, OU=stantec, DC=corp, DC=ads Date: 2024.05.16 10:12:41-03'00'

Prepared by ______________________________
(signature)

Mike Richard

Grey, Rick Digitally signed by Grey, Rick DN: CN="Grey, Rick", OU=Internal, OU=users, OU=stantec, DC=corp, DC=ads Date: 2024.05.16 15:05:26-03'00'

Reviewed by ______________________________
(signature)

Rick Grey

Peter Gregory Oliver -- P. Eng. - PEGNL Digitally signed by Peter Gregory Oliver -- P. Eng. - PEGNL Date: 2024.05.17 07:46:09 -02'30'

Approved by ______________________________
(signature)

Greg Oliver

Table of Contents

EXECUTIVE SUMMARY 1

1.0 INTRODUCTION 2

2.0 PREFERRED CONFIGURATION PARAMETERS 3

3.0 RESULTS OF MARKET SURVEY 4
3.1 USP&E 4
3.2 UNRESPONSIVE OEMS 5

4.0 GENERATOR STEP-UP TRANSFORMERS 6
4.1 PTI TRANSFORMER 6
4.2 GE/PROLEC 6
4.3 SIEMENS ENERGY 7
4.4 HYUNDAI 7
4.5 ABB/HITACHI 7
4.6 CTS SALES 8

5.0 UNIT CRITERIA COMPARISON 9

6.0 COST COMPARISON 10

7.0 CONCLUSIONS 10
7.1 TURBINES 10
7.2 TRANSFORMERS 10
7.3 COST COMPARISON 11

LIST OF APPENDICES

Appendix A VENDOR RESPONSES-TURBINES (Omitted in Redacted Report)
Appendix B VENDOR RESPONSES - TRANSFORMERS (Omitted in Redacted Report)

May 16, 2024

EXECUTIVE SUMMARY

The focus of this report is to identify combustion turbine options, of one or more units to provide 150 MWe, that may be readily available for an accelerated installation schedule at NL Hydro's (NLH) Holyrood generating facility. The availability and suitability of grey market units from existing inventory were the focus of this study. Engagement of OEMs and equipment packagers for combustion turbines primarily for emergency and peak load service, and with synchronous condensing capability was sought in the initial phases of the work package. Similar requests for suitable transformer supply were also sent out.

In general, responses were not supportive of rapid availability for supply/delivery of grey-market equipment. No grey market units were located that completely met NLH requirements. The only grey market respondent featured units not configured for diesel fuel usage, nor equipped with synchronous condensers, but can be modified for these features.

Similarly, no grey market transformers suitable for NLH were located. In general, other than a 175 MVA transformer quote received from [redacted] the potential suppliers of 175 MVA transformers independent from the turbine supply sources seemed unwilling or unable to provide data. Vendors seemed more willing or able to accommodate the supply of the 75MVA units separately. The delivery was noted to be greatly reduced if the transformers were sourced from [redacted] manufacturer deliveries ranged from 28 months to 48 months, deliveries from [redacted] ranged from 24 to 26 months, while [redacted] manufactured transformer deliveries ranged from 12 months to 18 months.

May 16, 2024

1.0 INTRODUCTION

The focus of this report is to identify combustion turbine options, of one or more units to provide 150 MWe, that may be readily available for an accelerated installation schedule. The availability and suitability of grey market units from existing inventory were the focus of this study. Engagement of OEMs and equipment packagers for combustion turbines primarily for emergency and peak load service, and with synchronous condensing capability was sought in the initial phases of the work package.

A concise description (datasheet) of the equipment requirements was prepared. OEMs and equipment packagers were contacted to see what units they have available for quick delivery and if they have knowledge of units that were never put into service or have only limited run time before the plant was shut down.

May 16, 2024

2.0 PREFERRED CONFIGURATION PARAMETERS

The preferred configuration for combustion turbine generation was developed in conjunction with NLH and was used to produce a Request for Information (RFI) for issue to prospective suppliers. Vendors were instructed that Newfoundland & Labrador Hydro has a future requirement for 150 MWe of simple cycle combustion turbine generation at its Holyrood Thermal Generating Station, near St. John's, NL, Canada, for load peaking, emergency service and synchronous condensing. The preferred configuration is as follows:

- Capacity may be provided via a single unit or up to three units - ie: 1 x 150 MWe or 3 x 50 MWe with 0.85pf.
- Primary fuel supply shall be No. 2 Diesel Fuel. The ability to operate on, or to be converted to, alternate fuels in the future will be an added benefit, including Hydrogen, Natural Gas and Biofuels such as HDRD (Renewable Diesel)
- Unit(s) shall be capable of synchronous condensing.
- Unit(s) shall be capable of fast start, with rated generation in no more than 10 minutes.
- Combustion turbine supply shall include air inlet filtration unit, exhaust stack, start-up system, instrumentation and control system, and medium and low voltage switchgear.
- Combustion turbine supply shall include Best Available Control Technology (BACT) for emission control.
- Rapid deployment of this 150 MWe of generating capacity may become necessary, so preference is for unit(s) that may be currently available due to cancelled or delayed projects, or existing/refurbished units with low running hours/starts. Mobile generation units may also be considered.

Vendors were encouraged to include supply for matching generator step-up transformer(s), as follows:

- 1 x 175 MVA or 3 x 75 MVA to match proposed turbine(s)
- 230 kV high voltage windings, secondary windings to match proposed turbine generator
- Delta-Grounded Wye
- De-energized HV Taps (+/- 5% in 2.5% Steps)

A separate RFI covering only the transformer(s), configured as above, was issued in parallel with the turbine RFI.

May 16, 2024

3.0 RESULTS OF MARKET SURVEY

The RFI was issued to the following turbine vendors, who were also asked to supply transformers if available:

Vendor	Contact Name	Email
GE Vernova	[redacted]	[redacted]
Siemens	[redacted]	[redacted]
Mitsubishi	[redacted]	[redacted]
Baker Hughes	[redacted]	[redacted]
IHI Power systems	[redacted]	[redacted]
Ansaldo Energia	[redacted]	[redacted]
Pro Energy	[redacted]	[redacted]
Aaron Equipment	[redacted]	[redacted]
Phoenix Equipment Corporation	[redacted]	[redacted]
USP&E	[redacted]	[redacted]
Industrial Marine Power	[redacted]	[redacted]

Of all vendors, only [redacted] responded. Of those four respondents, only [redacted] has available grey market options available at the time of RFI issue. The other three respondents offered new turbines. Grey market responses are detailed below.

3.1 [redacted]

Criteria	Offering
GT Configuration (GREY MARKET UNITS)	Currently have six [redacted] turbines. Units do not feature synchronous condensers. NLH would require three units to achieve 150 MW. Units are set up for natural gas but can be converted to dual fuel to also utilize diesel. Units manufactured in [redacted]
Delivery Schedule GT	Available (as of March 2024)
Delivery Schedule Step-Up Transformer	N/A
Budgetary Costs (USD)	$72,000,000

3.2 UNRESPONSIVE OEMS

The remaining OEMs on the distribution list indicated they did not have suitable equipment for a response or chose not to respond to the RFI.

May 16, 2024

4.0 GENERATOR STEP-UP TRANSFORMERS

A separate RFI was issued solely for transformer supply to the following vendors:

Vendor	Contact Name	Email
PTI Transformer	[redacted]	
GE/Prolec		
Siemens Energy		
Hyundai		
ABB/Hitachi		
CTS Sales		

The results of the RFI are summarized in the following sections. Similar to the turbine vendors, vendors only quoted new options and did not offer any grey market alternatives.

4.1 [redacted]

Option 1 Criteria	Offering
1 – 175 MVA, 230 kV/13.8 kV Power Transformer	Budget Quote [redacted] for single transformer and freight
Budgetary Cost (CAD)	$5,983,000
Delivery Schedule	48 Months [redacted]
Option 2 Criteria	**Offering**
3 – 75 MVA, 230kV/13.8 kV Power Transformers	Budget Quote Q100893B for three transformers and freight
Budgetary Cost (CAD)	$10,617,000 (Includes freight)
Delivery Schedule	48 Months [redacted]

4.2 [redacted]

Option 1 Criteria	Offering
1 – 175 MVA, 230 kV/13.8 kV Power Transformer	Not offered
Budgetary Cost (USD)	N/A
Delivery Schedule	N/A
Option 2 Criteria	**Offering**
3 – 75 MVA, 230 kV/13.8 kV Power Transformers	
Budgetary Cost (USD)	$4,800,000 (Not including delivery) $7,150,000 (Includes delivery)

Delivery Schedule	12 months [redacted] 24 months [redacted] 36 months [redacted]

4.3 [redacted]

Option 1 Criteria	Offering
1 – 150/175/200 MVA, 230 kV/13.8 kV Power Transformer	
Budgetary Cost (CAD)	$4,500,000 to $5,000,000
Delivery Schedule	18 months [redacted]
Option 2 Criteria	**Offering**
3 – 60 MVA, 230 kV/13.8 kV Power Transformers	
Budgetary Cost (CA)	$2,500,000 to $3,000,000
Delivery Schedule	18 months [redacted]

4.4 [redacted]

Option 1 Criteria	Offering
1 – 175 MVA, 230 kV/13.8 kV Power Transformer	Not offered
Budgetary Cost (CAD)	Not provided. Will offer only if delivery schedule is acceptable
Delivery Schedule	48 Months
Option 2 Criteria	**Offering**
3 – 75 MVA, 230 kV/13.8 kV Power Transformers	Not offered
Budgetary Cost (CAD)	Not provided. Will offer only if delivery schedule is acceptable
Delivery Schedule	48 Months

4.5 [redacted]

Option 1 Criteria	Offering
1 – 175 MVA, 230 kV/13.8 kV Power Transformer	Budget Quote [redacted] for single transformer and freight
Budgetary Cost (CAD)	$5,900,000 including freight
Delivery Schedule	24 - 26 Months [redacted]
Option 2 Criteria	**Offering**
3 – 75 MVA, 230 kV/13.8 kV Power Transformers	Budget Quote [redacted] for three transformers and freight

Budgetary Cost (CAD)	$12,450,000 including freight
Delivery Schedule	24 - 26 Months [redacted]

4.6 [redacted]

Option 1 Criteria	Offering
1 – 175 MVA, 230 kV/13.8 kV Power Transformer	Not offered
Budgetary Cost (USD)	N/A
Delivery Schedule	N/A
Option 2 Criteria	**Offering**
3 – 75 MVA, 230 kV/13.8 kV Power Transformers	[redacted]
Budgetary Cost (USD)	$9,000,000 (not including freight)
Delivery Schedule	28 to 34 months [redacted]

May 16, 2024

5.0 UNIT CRITERIA COMPARISON

The following is a comparison of the [redacted] grey market units and the preferred configuration criteria:

Preferred Configuration	Analysis
Capacity may be provided via a single unit or up to three units - ie: 1 x 150 MWe or 3 x 50 MWe with 0.85pf.	Zero hour [redacted] MW turbines. Three of the six units would be required ([redacted] MW).
Primary fuel supply shall be No. 2 Diesel Fuel. The ability to operate on, or to be converted to, alternate fuels in the future will be an added benefit, including Hydrogen, Natural Gas and Biofuels such as HDRD (Renewable Diesel)	Units are currently configured for natural gas. They would need to be converted to run on No.2 Diesel Fuel.
Unit(s) shall be capable of synchronous condensing.	Not available with these units. Could be added as a retrofit.
Unit(s) shall be capable of fast start, with rated generation in no more than 10 minutes.	Yes, based on [redacted] literature.
Combustion turbine supply shall include air inlet filtration unit, exhaust stack, start-up system, instrumentation and control system, and medium and low voltage switchgear.	Yes, included as part of the package, except for exhaust. Note, this unit was built for the [redacted] market. There is a potential the components do not meet CSA standards and would require review and registration, e.g. pressure vessels and fittings Canadian Registration Number (CRN). Since this unit originated as a combined cycle plant, it would be supplied simple cycle without an exhaust. An exhaust would be an additional cost.
Combustion turbine supply shall include Best Available Control Technology (BACT) for emission control.	Equipped with a Dry Low Emission (DLE) system for Natural Gas. A DLE system can be used with Diesel Fuel. DLE may not be the Best Available Control Technology and would need further investigation.
Rapid deployment of this 150 MWe of generating capacity may become necessary, so preference is for unit(s) that may be currently available due to cancelled or delayed projects, or existing/refurbished units with low running hours/starts. Mobile generation units may also be considered.	Units are currently available for purchase with zero run hours.

From a generation perspective, the units will meet the preferred capacity of 150MW however, they do not come with synchronous condenser capability, require a fuel conversion from natural gas to Diesel Fuel, and require an exhaust system.

Although the [redacted] units are currently available, Newfoundland & Labrador Hydro are not currently in a position to purchase at this time due to internal project approvals, environmental assessment, and a Public Utilities Board (PUB) project sanction. In addition, engineering design and site civil work would be required before unit installation can take place which could be upwards of two years before installation. Therefore, purchasing these units would require storage and preservation over the coming years until the site civil work is completed.

6.0 COST COMPARISON

This cost comparison is between the three grey market [redacted] and a new turbine supply option of similar scope. The associated cost comparison directly relates to unit costs and not the overall project cost.

3 x	**Grey Market Turbine**	$72,000,000 USD
3 x	**New Turbine**	$105,000,000 USD

While the grey market option appear to be less expensive, they are not configured properly for NLH purposes as noted in Section 5.0.

Additional cost would be associated with the following should the grey market option be considered:

- Conversion from Natural Gas to Diesel Fuel.
- Conversion or purchase of the generator to a synchronous condenser unit.
- Purchase of an exhaust system.
- Shipping components from [redacted] to Newfoundland.
- Storage and preservation costs
- Potential BACT system upgrades

7.0 CONCLUSIONS

7.1 TURBINES

Only one vendor, [redacted], offered used units from inventory but would require a deposit to hold. These units are not configured to burn diesel fuel, are not capable of operation as a synchronous condenser and do not include an exhaust system. In addition, the units were built for the [redacted] market and there is a potential the components do not meet CSA standards.

7.2 TRANSFORMERS

In general, other than a 175 MVA transformer quotes received from [redacted] and [redacted] the potential suppliers of 175 MVA transformers independent from the turbine supply sources seemed unwilling or unable to provide data. Vendors seemed more willing or able to accommodate the supply of the 75 MVA units separately. While the $7,150,000 to $9,000,000 USD cost for three of these 75 MVA units did not vary greatly between different vendors, the delivery was noted to be greatly reduced if the transformers were sourced from [redacted]. [redacted] manufacturer deliveries ranged from 28 months to 48 months, deliveries from [redacted] ranged from 24 to 26 months, while [redacted] manufactured transformer deliveries ranged from 12 months to 18 months.

No grey market transformers suitable for NLH were located meeting the required ratings. Equipment vendors were requested to advise on potential availability of refurbished or used transformers as well as new units. Other than a verbal conversation with one transformer supplier identifying the risks of dismantling, relocating, and restoring a used transformer back into service without proper detailed knowledge of its operating history, no response was received by any vendors on the availability of used units.

7.3 COST COMPARISON

The only grey market offering appeared to have a cost reduction compared to new units but would require a fuel conversion from gas to liquid fuel, synchronous condensers, exhaust system, shipment from [redacted], potential BACT system upgrades, and storage and preservation costs.

May 16, 2024

APPENDIX A
VENDOR RESPONSES -TURBINES

(Omitted in Redacted Report)

May 16, 2024

APPENDIX B
VENDOR RESPONSES - TRANSFORMERS

(Omitted in Redacted Report)

Appendix C
Attachment 4

Appendix C, Attachment 4

Long-Term Fuel Supply Study, Holyrood

Stantec Consulting Ltd.

May 6, 2024

Long Term Fuel Supply Study, Holyrood

May 6, 2024

Prepared for:
Brian Sparkes
Market Analysis and Load Forecasting
Newfoundland and Labrador Hydro
P.O. Box 12800
500 Columbus Drive
St. John's, NL A1B 0C9

Prepared by:
Stantec Consulting Ltd.,
141 Kelsey Drive
St. John's, NL A1B 0L2

Project Number:
133549631

Limitations and Sign-off

This document entitled Long Term Fuel Supply Study - Holyrood was prepared by Stantec Consulting Ltd. ("Stantec") for the account of Newfoundland and Labrador Hydro (the "Client"). Any reliance on this document by any third party is strictly prohibited. The material in it reflects Stantec's professional judgment in light of the scope, schedule and other limitations stated in the document and in the contract between Stantec and the Client. The opinions in the document are based on conditions and information existing at the time the document was published and do not take into account any subsequent changes. In preparing the document, Stantec did not verify information supplied to it by others. Any use which a third party makes of this document is the responsibility of such third party. Such third party agrees that Stantec shall not be responsible for costs or damages of any kind, if any, suffered by it or any other third party as a result of decisions made or actions taken based on this document.

Greg Oliver

Reviewed by

(signature)

Ken Harding

Prepared by (signature)

Aaron Cameron

Prepared by

(signature)

Vicki Corning

Prepared by

(signature)

Pietro Di Zanno

Prepared by

(signature)

Table of Contents

1 EXECUTIVE SUMMARY VII

2 INTRODUCTION AND BACKGROUND 1
2.1 PREAMBLE 1
2.2 HOLYROOD THERMAL GENERATING STATION AND TERMINAL 4
2.3 HOLYROOD GAS TURBINE(S) 5

3 REPORT STRUCTURE 8

4 PART 1: MARKET FORECAST AND AVAILABILITY FOR NO.2 DIESEL 9
4.1 AN OVERVIEW OF CANADA'S REFINING SECTOR 9
4.1.1 Commercial Production of Conventional Fuels in Canada 9
4.1.2 Commercial Production of Unconventional Green Fuels in Canada 20
4.2 AN OVERVIEW OF US REFINING SECTOR 33
4.2.1 Introduction 33
4.2.2 US Refining 34
4.2.3 US Biodiesel and Renewable Diesel 39
4.3 MARKET CHANGES 41
4.3.1 Industry Structure 41
4.3.2 Residential Heating 41
4.3.3 Vehicle Electrification 42
4.4 REGULATION IN CANADA 44
4.4.1 Canada's Electric Vehicle Availability Standard 45
4.4.2 Clean Electricity Regulations 46
4.4.3 Clean Fuel Regulations 49
4.4.4 Greenhouse Gas Regulations 51
4.4.5 Oil and Gas Sector Cap 54
4.4.6 Summary of Canadian Regulatory Influences 55
4.5 REGULATION IN US 56
4.5.1 Summary of US Regulatory Influences 66
4.6 SUMMARY 66

5 PART 2: REVIEW OF EXISTING HYDRO SUPPLY CHAIN PROCESSES 68
5.1 INTRODUCTION 68
5.2 DELIVERY TIME (FUEL RECEIPTS): OVERALL CONTRACTING STRATEGY, SCHEDULE 68
5.3 ASSET UTILIZATION: LIMITATIONS AND OPPORTUNITIES – TRANSPORT, STORAGE, OTHER AS APPLICABLE 75
5.4 INVENTORY MANAGEMENT – MAXIMUM STORAGE CAPACITY 77
5.5 SUPPLY CHAIN ALTERNATIVES – PRICING IMPACTS, OTHER AS APPLICABLE 77
5.6 ASSESSMENT OF DECLINING AVAILABILITY OF NO. 2 DIESEL IN THE REGIONAL AND LOCAL MARKET 78
5.7 RISK REVIEW 83

5.8 SUMMARY AND RECOMMENDATION 87

6 PART 3: CRITICAL ASSETS TO THE TOTAL SUPPLY CHAIN (FROM FUEL PRODUCER TO HYDRO) 88
6.1 CLIMATE DRIVEN DISRUPTIONS: FROM FEEDSTOCK AVAILABILITY TO IMPACTS ON DELIVERED FUEL PRICE 88
6.2 REFINERY CONVERSIONS / REDUNDANCY / CLOSURES: AS FUNCTION OF THE ENERGY TRANSITION, SUPPLY VOLATILITY 89
6.3 REGULATION: CURRENT AND FUTURE 92
6.4 TURBINE: CURRENT AND FUTURE OF POWER CONVERSION TECHNOLOGY 92
6.5 GENERAL: DEMAND VOLATILITY, ECONOMY / INFLATION, GEOPOLITICS, REGIONAL LABOUR RELATIONS 93

7 PART 4: PROVIDE OUTLOOK TO ALTERNATIVE FUEL SOURCES AND POTENTIAL TIMELINE 95
7.1 INTRODUCTION 95
7.2 ENERGY DENSITY OF SELECT FUELS 95
7.3 FUEL COMPOSITION AND FUEL STABILITY 97
7.4 CLEAN FUELS 99
7.4.1 Biodiesel and Renewable Diesel 100
7.4.2 Biomass 104
7.4.3 Hydrogen 104
7.4.4 Natural Gas - Compressed and Liquified 113
7.4.5 Oxygenates 114
7.4.6 Synthetic Fuels 117

8 SUMMARY: KEY OBSERVATIONS AND RECOMMENDATIONS 121
8.1 KEY OBSERVATIONS 121
8.2 RECOMMENDATIONS 124

9 APPENDIX 125
9.1 ABBREVIATIONS 125
9.2 DIESEL ASTM 128
9.3 KEY DEFINITIONS 129
9.4 NOMENCLATURE 130
9.5 TECHNICAL AND COMMERCIAL READINESS LEVEL 130
9.6 REPORT METHODOLOGY 132
9.7 TEST METHODS – DIESEL STABILITY 133

LIST OF REPORT TABLES

Table 1 Fuel Consumption and Inventory Requirement at Holyrood (Gas Turbines) 6
Table 2 Fuel Consumption at Holyrood Gas Turbine (2015 to 2023) 7
Table 3 Canadian Refineries – Location and Capacity (barrels)....12
Table 4 Canadian Refineries – Location and Capacity (million liters)....13
Table 5 Canadian Production of Transportation Fuels (Units: barrels per day) 17
Table 6 Canadian Production of Transportation Fuels (Units: million liters per day)....18
Table 7 Diesel – biodiesel blending mandate....21
Table 8 Gasoline – Ethanol Blending Mandate 21
Table 9 Biodiesel Facilities in Canada - Operating....24
Table 10 Renewable Diesel Facilities in Canada – Publicly Announced 25
Table 11 Biodiesel Production Technology - Operating Plant 26
Table 12 Renewable Diesel Production Technology – New Plant....27
Table 13 Ethanol (1G) Production in Canada....29
Table 14 Ethanol Production in Canada by Province 30
Table 15 Ethanol Consumption per Capita – Canada versus USA....30
Table 16 Renewable Diesel and Ethanol Demand; Units: barrels / day....31
Table 17 Renewable Diesel and Ethanol Demand; Units: million liters / day....32
Table 18 US Operable Refineries by PADD (January 2023)....36
Table 19 Diesel Production in the US (rough order of magnitude) 39
Table 20 U.S. Renewable Diesel Fuel and Other Biofuels Production Capacity (January 2024)....40
Table 21 Newfoundland and Labrador: Road Vehicle Registrations, 2017 to 2022....43
Table 22 Canadian Vehicle Fleet: Diesel versus Gasoline, 2017 - 2022 44
Table 23 Cost of Emission Credits under Clean Electricity Regulations....49
Table 24 Estimate of Compliance Cost under Greenhouse Gas Regulations 52
Table 25 Estimate of Daily Compliance Cost in 2030 under the Management of Greenhouse Gas Regulations....53
Table 26 Production levels Assumed by ECCC in Developing Caps....54
Table 27 US Direct GHG Emissions by Sector (2022) 60
Table 28 US Refinery Emissions by State (2022) 62
Table 29 US Refinery Emissions by PADD (2022)....63
Table 30 Supply Contracts: Bidder and Award History....69
Table 31 East Coast Shippers (Canadian)....70
Table 32 Newfoundland Fuel Terminals....71
Table 33 Holyrood Gas Turbines – Annual Diesel Demand (assumption)....72
Table 34 Holyrood Gas Turbines: Asset Utilization 75
Table 35 Fuel Diesel Investment Costs....76
Table 36 Risk Matrix: Inbound and Outbound Risk Factors 84
Table 37 Comparison of Diesel with other fuel types 96
Table 38 Biodiesel Types....101
Table 39 Hydrogen Production Pathways 105
Table 40 Energy Equivalent for Holyrood – Diesel to Hydrogen (Kilograms to Megajoules) 108
Table 41 Energy Equivalent for Holyrood - Hydrogen (kWh)....108
Table 42 Power Required to Produce and Liquefy Hydrogen (1 kg)....109

Table 43 Total Power Required for Hydrogen – Scenario 1 to 4 110
Table 44 Energy Equivalent for Holyrood – Diesel to Ammonia (Kilograms to Megajoules) 111
Table 45 Holyrood: Ammonia versus Diesel Emissions - Comparison 112
Table 46 Ammonia Shipment...113
Table 47 Alcohols as Fuel / Blend-stock 115
Table 48 Dimethyl Ether and Polyoxymethylene Ethers..116
Table 49 Synfuel Plants...118
Table 50 Primary and Secondary Data Sources 132

LIST OF REPORT FIGURES

Figure 1 Hatch – Summary of Site Selection Results (September; 2023) ... 2
Figure 2 Holyrood Thermal Generating Station and Terminal ... 5
Figure 3 Holyrood Gas Turbine and Storage Tanks: current and proposed (3x50MW) ... 7
Figure 4 A timeline of Canadian refinery capacity ... 10
Figure 5 Location of Canadian refineries ... 11
Figure 6 Canadian Conventional Refining - Installed, % Utilization and Operating Capacity ... 14
Figure 7 Canadian Refining - Percentage by Product ... 14
Figure 8 Canadian Refining - Percentage by Product (simplified) ... 15
Figure 9 Canadian Refinery - Refined Products Split ... 15
Figure 10 Canadian Conventional Refining Capacity by Product (bbls. / day) ... 16
Figure 11 Canadian Conventional Refining Capacity by Product (million liters / day) ... 19
Figure 12 Canadian Fuels Association members ... 20
Figure 13 Canada's Renewable / Low Carbon Fuel Mandates ... 22
Figure 14 Biofuels Canada – Capacity Forecast ... 22
Figure 15 World Crude Oil and Lease Condensate Production (EIA) ... 33
Figure 16 World Liquid Fuels Consumption (EIA) ... 33
Figure 17 US Production of Petroleum Products 2024 through 2050 ... 34
Figure 18 Market Share of Electric Light-Duty Vehicles, US (EIA) ... 34
Figure 19 US EIA Petroleum Administration for Defense Districts ... 35
Figure 20 Location of US Refineries ... 37
Figure 21 US Refinery Utilization (1995 – 2020) ... 38
Figure 22 Distillate Fuel by End Use, US ... 38
Figure 23 US Existing and Forecast Renewable Diesel Production Capacity (2010 - 2025) ... 40
Figure 24 Crude Oil, Refining and Fuels – An Evolving Sector ... 41
Figure 25 Canada Electric Vehicle Availability Standard ... 45
Figure 26 Carbon Pricing – Prices and Coverage (World Bank 2023) ... 57
Figure 27 (a) Global Carbon Pricing Schemes (World Bank 2023) ... 58
Figure 28 (b) Global Carbon Pricing Schemes (World Bank 2023) ... 58
Figure 29 (c) Global Carbon Pricing Schemes (World Bank 2023) ... 59
Figure 30 US Direct GHG Emissions by Sector (2022) ... 60
Figure 31 US Direct GHG Emissions by Sector (2012 to 2022) ... 61
Figure 32 Come-By-Chance Refinery to Holyrood Thermal Station ... 70
Figure 33 Incoterms 2020 – Point of Delivery and Transfer of Risk ... 73
Figure 34 US Ending Stocks Distillate Fuel – All, PADD 1A, 1B, 1C ... 79
Figure 35 US Ending Stocks Distillate Fuel – PADD 1A, 1B, 1C ... 79
Figure 36 US Refiner Net Production; Distillate (0-15 ppm S), Finished Gasoline ... 80
Figure 37 Refinery production versus consumption (PADD-1 and PADD-2) ... 81
Figure 38 Domestic Movements – PADD-1 and PADD-2 ... 81
Figure 39 US East Coast Ports: PADD-1 ... 82
Figure 40 US East Coast Fuel Market Dynamics ... 82
Figure 41 Risk Profile: Inbound Risk Factors ... 85
Figure 42 Risk Profile: Outbound Risk Factors ... 86
Figure 43 Rongsheng Petrochemical ... 90

Figure 44 (a) Technology Development in the Refining Sector 91
Figure 45 (b) Technology Development in the Refining Sector 91
Figure 46 Global Crude Oil Tanker Shipping 93
Figure 47 Global Chemical Tanker Shipping 94
Figure 48 Chemical Composition of Fats, Grease, and Oil Seeds 103
Figure 49 Hydrogen Production – Conventional Technology 105
Figure 50 Hydrogen Production – Emerging Technology 106
Figure 51 Wind Energy Projects Near the Avalon Peninsula, NL 107
Figure 52 CNG and LNG Virtual Pipeline 113
Figure 53 Dimethyl Ether – Properties, Advantages and Disadvantages 117
Figure 54 (a) Diesel No. 2 ASTM 128
Figure 55 (b) Diesel No. 2 ASTM (continued) 129
Figure 56 Technology Readiness Level (TRL) 131
Figure 57 Commercial Readiness Level (CRL) 131
Figure 58 Commonly used oxidative stability measurement techniques for diesel 133

1 EXECUTIVE SUMMARY

In December 2023, Newfoundland and Labrador Hydro ('Hydro') engaged Stantec to assist in developing a plan for the strategic and long-term supply of No. 2 Diesel and alternative fuel(s) as may be technically possible for the existing and future gas turbines at Holyrood, NL of 123MW and 150MW respectively.

Principal objectives of the study were to conduct / provide the following:

- Part 1: Market forecast and availability for No.2 Diesel,
- Part 2: Review existing supply chain processes to identify risks and potential improvements,
- Part 3: Outline any critical assets to the total supply chain (from fuel producer to Hydro), and
- Part 4: Provide an outlook to alternative fuels sources (biofuel, hydrogen) and a potential timeline.

Stantec's observations and findings are summarized below.

Market Forecast and Availability of No.2 Diesel

Canada's oil and gas sector along with that of refining and fuel supply, is coming under increasing structural pressure both directly and indirectly. This may in the longer-term cause domestic refiners to consider reducing capacity or to exit the market at least in terms of production. Refineries may restructure sites to non-producing terminal activities of those products and markets which remain profitable.

A factor that needs to be considered, is the size of the Canadian refining sector relative to competing jurisdictions and where the sector sees its future markets. Refiners producing liquid transport fuels in a decarbonizing era must ultimately ask - when do I cease production? As circumstance dictates, not all will close at the same time. Staying operational will depend on what market a refiner might direct its business profitably to.

The US refining sector in contrast is considerably larger than Canada's and, in some states, faced with circumstances not dissimilar to Canada's. On numerous qualitative considerations however, deeper comparison demonstrates the countries sectors differ significantly. The outlook for US refiners, if not overly positive, is at least optimistically neutral for a continuance of operations through 2050.

The strategic importance of the US refining and petrochemical sector to their economy along with international security should not be underestimated to the extent that both sectors can be expected to be somewhat shielded from decarbonization initiatives at least until a viable substitution has been identified, built, and proven. For this reason, we do not see medium nor longer-term risk to the production of traditional #2 diesel fuel in the US.

Molière (2023)[68] comments to the importance of reliable fast start gas turbines and their role in the energy transition, speaking to the fact the transition will require back-up power systems when renewable power falters. Government and society by implication, will maintain an operating base of refineries (conventional / new) to ensure stable supply of fuel to gas turbines to cover such events.

Regulatory Factors

Canada has embraced several regulatory initiatives with real intention to reduce industrial emissions, from softer initiatives like consumer access to EV's to formal regulation on clean electricity, greenhouse gas emissions and capping growth in oil and gas production. All are likely to cause Canada's conventional refining sector to evaluate continued operations as they approach the middle years and 2050. **Whether diesel or suitable fossil-based alternative produced in Canadian refineries will be available in 2040 is uncertain. What is more certain is the continued availability of both options from US refineries for simple expediency of US economy, geopolitics, and national security.**

Supply Chain Processes – Risks / Improvements

Bidder response to RFPs is severely limited with North Atlantic Refining winning the contract for the three cycles to date. On-island companies (Valero Energy, Irving Oil) not submitting supply proposals, suggests possible issues with the overall contract strategy, a lack of awareness of the RFP or an erosion of supplier pool as participants exit the market or restructure their business model. **To secure diesel in the future, it is vital to identify barriers to bidders and to develop a larger and more diverse supplier pool.**

On-island logistics with inventory management because of the urgent nature of the supply need during emergencies is a concern. Truck and driver availability on short notice possibly during severe weather where roadways are not open, and where accessible fuel storage is possibly scattered across the island is a concern that needs to be addressed in emergency response plans. **Holyrood's five-day inventory plan does provide some security, but additional storage options closer to the gas turbine(s) themselves to reduce or remove reliance on road transportation are recommended.**

As Hydro continues operating the Holyrood gas turbine as an emergency / peak power provider, this along with the possibility of new generation capacity in the future, requires implementation of a protocol to manage procurement and product quality against fuel instability. The change in operating philosophy with a possible significant increase in diesel required also suggests Hydro explore wider procurement options. **Access agreements, supplier managed inventory partnerships, or a just-in-time contracting strategy or combinations thereof, could reduce initial investment cost in inventory and Hydro's risk that comes with carrying a large inventory.**

Critical Assets

Since first constructed, refineries have never remained static. From lighting fluid to gasoline for an emerging auto sector, both in war and peace, refineries have evolved in response to global events. Modern aviation and plastics both owe their beginnings to technology discoveries and advances of World War II. Rather than close, refineries have evolved and can be expected to continue doing so.

In the past decade, those refiners with the vision / resources have responded to not only climate change concerns, but also the emergence of hybrids / EV's and the threat this poses to their business model. Whilst refiners are likely to increase focus on chemicals, the base feedstocks and processes themselves inside of refineries do not disappear. Refiners within reason, can choose which market they address.

Geopolitical events are not new and by nature disrupt the global economy. Less well known is the scale at which commodities and products of various description travel the world.

In the 1950's to the 1980's products servicing daily lives were likely produced a county, or province over. This is less true today, crude and chemicals are examples of product traded globally to the extent that when disrupted, the impact is mitigated by the availability of alternatives and the scale of the activity itself.

Demand volatility, state of the economy (interest rates, inflation) geopolitics, regional labor relations and other factors are for the most part, out of Hydro's ability to influence. The remaining option is to acknowledge such events and from that, determine how they might be mitigated.

Should supply of bulk diesel to Newfoundland be disrupted from mainland Canada or East Coast US, there are options. Supply from further afield e.g. Europe is possible, but will require intentional planning.

Alternative Fuels

An 'alternative fuel' by definition, may only be classified an 'alternative' if the candidate is able to meet the operational needs of the circumstances to which it is to be deployed - current and future.

In providing a broader description of fuels, Stantec narrowed the conversation to those alternatives that realistically might find a place in Newfoundland's unique setting. For reason of physical properties, no fuel is as perfect as fossil-derived diesel appears.

Hydrogen is disqualified as an alternative on account of practical reasons relating to production, unavailable green power, viable transport and long-term storage and the very volume required for the existing and future gas turbines at Holyrood, or other location. The challenges for the present are very significant as well as likely cost prohibitive if they were not. In acknowledgement of this, ammonia was analyzed. However, until gas turbine vendors prove ammonia a viable fuel, it will remain an idea and a consideration utility companies can only observe with future interest.

Biodiesel as produced by the reaction of ethanol and animal fats or similar with limited further processing is disqualified on basis of the fuel not being suitable to Canadian conditions and unstable in long-term storage. Production of renewable diesel in contrast, involves multiple and chemically more sophisticated processes that can produce a product to Canadian requirements. This is not where the challenge lies however - **sourcing large volumes of said product can be expected to be slightly to very challenging as producers will direct sales to markets willing to pay a premium for the privilege in their own right or as function of their own jurisdictional requirements / subsidies.**

Bioethanol may be an alternative in the future. There are several references to the use of ethanol in gas turbines, however these have been in countries like Brazil that produce ethanol at large scale. **Whilst ethanol has positive attributes, it is penalized by a low energy density implying 1.68 times volumetric increase compared to diesel with associated logistics implications.** The volumetric constraint might be overcome with larger onsite storage delivered seasonally by barge or coastal tanker and the matter of long-term product stability addressed by storing under nitrogen.

2 INTRODUCTION AND BACKGROUND

In October 2023, Hydro issued a Professional Service Request (PSR) for a consultant to assist Hydro in developing a plan for the strategic and long-term supply of No. 2 Diesel and alternative fuel(s) as may be technically possible to the existing and future additional gas turbines at Holyrood, NL of 123.5MW and approximately 150MW (3 x 50MW[1]) respectively.

Given the importance of electricity in communities, it is to be expected that power producers and utility providers like Hydro will continuously monitor their own generating capacity, electrical grid network and fuel supply-chain to ensure reliable and stable power supply to their customers year-round, and more importantly do this against the backdrop of a world in which the manner by which electricity is produced and used continues to evolve.

Climate-change heralds a wholly new setting that is not only scrutinizing: (i) how we produce electricity, but (ii) how and (iii) where we use electricity. All three questions naturally have implications for traditional refiners, the fuels they produce and their customers like Hydro where the latter must examine their current and future operational options against looming change in the former.

2.1 PREAMBLE

The following provides a summary of events from 2022 to Stantec's January 2024 appointment to the present study.

Reliability and Resource Adequacy Study - 2022 Update, October 3, 2022

At more than 300 pages, the update covered the following items:

- Planning for Today, Tomorrow, and the Future – 2022 Update, a summary document that briefly highlights key considerations of the 2022 Update;
- Hydro's Study Methodology and Planning Criteria; and
- Hydro's Long-Term Resource Plan.

The report makes the recommendation that additional generation is required to reliability meet the province's electricity needs. Until new sources of generation can be selected, approved by the Regulator, and constructed, both the Holyrood Thermal Generating Station (490MW) and Hardwoods Gas Turbine (50MW) are recommended to be kept available as backup in event of supply disruption.

Kalibrate, Phase-1 Report, Preliminary and Background Market Review, November 3, 2022

In their report, Kalibrate provides the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB-NL) background to the supply (source) of diesel and pricing thereof from refiners and suppliers located in Canada and USA respectively.

[1] Newfoundland and Labrador Hydro - Concept Design Report Final Report; 28 Sept. 2023; PDF Page number 89.

Newfoundland and Labrador Hydro – Reliability and Resource Adequacy, Study Review – 2022 Update – Further Process – Newfoundland Power's Comments, June 13, 2023

Hydro provides the PUB-NL on their listing of planned reports and similar planned or underway with respect to resource planning and potential alternative generation resources. Relevant commentary made in the document for noting in the context of the present study are:

- Holyrood TGS not being suitable as a fast start emergency / backup generator.
- A Combustion Turbine Feasibility Study underway with the likelihood of a Combustion Turbine Front End Engineering Design study to follow.
- Uncertainty around replacement of Holyrood TGS and Hardwoods GT capacity.

Hatch, Combustion Turbine Feasibility Study, September 28, 2023

In this report and based on agreed siting criteria, Hatch reviewed six locations at which combustion turbines might be located. The Northeast Avalon region, specifically Holyrood emerges as the recommended location[2] as shown in Figure 1 below. Holyrood was the only option located on the coast and more specifically within one (1) km of an existing terminal and storage tanks[3].

Hatch reviewed three capacity scenarios: 150MW, 300MW and 450MW; the report also considered the opportunity for alternative fuels - biofuel and ethanol, hydrogen and natural gas.

Table 1-4: Summary of Site Selection Results

Option	Site Name	Classification	Score	Preferred Rank
A	Holyrood TGS	Brownfield	87%	1
B	Paddy's Pond	Greenfield	63%	3
C	Sugarloaf Pond	Greenfield	51%	4
D	Soldiers Pond	Greenfield	70%	2
E	Bremigen's Pond	Greenfield	51%	4
F	Petty Harbour Long Pond	Greenfield	41%	5

Reference: Newfoundland and Labrador Hydro - Concept Design Report Final Report; Hatch; 28 Sept. 2023; PDF Page number 16.

Figure 1 Hatch – Summary of Site Selection Results (September; 2023)

[2] Hydro; Reliability and Resource Adequacy Study Review – Combustion Turbine Feasibility Study, October 4, 2023; PDF page no. 11.
[3] Note: the jetty and tanks referenced are configured for the delivery of Bunker-C fuel – are not multi-purpose.

Reliability and Resource Adequacy Study Review – Combustion Turbine Feasibility Study, October 4, 2023

In this document Hydro reviews the findings of Hatch's report. Extracts of note with bold text added are:

- In line with good utility practice, there is **a need for reliable backup generation** to address the uncertainty of the LIL's reliability'.[4]
- The review considered the use of a combustion turbine in the instance where it might be required to provide **backup generation for six consecutive weeks**, supporting reliable delivery of electricity, primarily during peak hours.[5]
- Scope for the Concept Design Report required Hatch to contemplate new combustion turbine(s) that would be **installed for emergency backup generation and load peaking as required**.[6]
- Review also included the criteria that any technology considered **must have fuel flexibility** that would allow Hydro to maintain compliance with Canada's **Clean Electricity Regulations**. Hatch reviewed three size scenarios (150 MW, 300 MW, and 450 MW) and **only the options that were capable of burning diesel, natural gas, biofuel, and hydrogen blends were considered**.[7]
- **Northeast Avalon is preferred due to the appreciable transmission constraints that limit power flow to the Avalon Peninsula**. The requirement for future transmission reinforcements would be reduced if generation supply, **or a combustion turbine, were to be located closer to the Northeast Avalon as the main load center**.[8]

Reliability and Resource Adequacy Study Review – Combustion Turbine Feasibility Study, October 13, 2023

Hydro provides feedback to PUB-NL as regards to the Hatch study. Extracts of note with bold text added from the attached Hatch report are:

- 1.10.2 Recommendations[9]
  - Aeroderivative gas turbines are good candidates,
  - Recommended plant site is the Holyrood site as it already has an **existing dock and road facility for both barge and truck delivery,**
  - Due to the large on-site fuel storage and transportation requirements for larger plant sizes we **recommend building a 150 MW** (nominal) power plant. A better alternative to a large plant

---

[4] Hydro; Reliability and Resource Adequacy Study Review – Combustion Turbine Feasibility Study, October 4, 2023; PDF page no. 4., lines 18 to 20.
[5] Hydro; Reliability and Resource Adequacy Study Review – Combustion Turbine Feasibility Study, October 4, 2023; PDF page no. 9, lines 2 to 3.
[6] Hydro; Reliability and Resource Adequacy Study Review – Combustion Turbine Feasibility Study, October 4, 2023; PDF page no. 9, lines 12 to 13.
[7] Hydro; Reliability and Resource Adequacy Study Review – Combustion Turbine Feasibility Study, October 4, 2023; PDF page no. 9, lines 17 to 18.
[8] Hydro; Reliability and Resource Adequacy Study Review – Combustion Turbine Feasibility Study, October 4, 2023; PDF page no. 10, lines 19 to 22.
[9] Hydro, Reliability and Resource Adequacy Study Review – Combustion Turbine Feasibility Study, 13th Oct. 2023. PDF page no. 20.

size of 300MW or 450MW is to build a smaller gas turbine back up plant of 150 MW to support the first project phase; and **further investigate the feasibility of larger plant sizes while considering renewable energy sources with battery storage or hydrogen for subsequent project phases**.

Reliability and Resource Adequacy Study Review – 2023 Near-Term Reliability Report; 15th November

In this document, Hydro provides feedback to PUB-NL and comments / suggests:

- Holyrood TGS should remain available for a "Bridging Period" until 2030[10, 11, 12].
- Consideration be given to extending the service life of the Stephenville GT[13].

Long Term Fuel Supply Study - Holyrood, Stantec January 2024

As part of the ongoing activities and studies listed above, Stantec was engaged by Hydro to conduct a long-term fuel supply strategy where this covered four key items:

- Part 1: Market forecast and availability for No.2 Diesel.
- Part 2: Review existing client supply chain processes to identify risks and potential improvements.
- Part 3: Outline Any Critical Assets to the Total Supply Chain (from fuel producer to Hydro).
- Part 4: Provide outlook to alternative fuels sources (bio-fuel, hydrogen) and a potential timeline.

2.2 HOLYROOD THERMAL GENERATING STATION AND TERMINAL

In their September 2023 study, Hatch determined the Holyrood Thermal Generating Station (Holyrood TGS) is not a long-term option to meet the growing power needs in the Avalon Peninsula. Consequently, the existing Holyrood TGS and it is assumed that unless otherwise decided, the associated marine fuel jetty with four bulk oil storage tanks, are scheduled for decommissioning in March 2030[14,15] Figure 2.

10 Hydro: Reliability and Resource Adequacy Study Review – 2023 Near-Term Reliability Report – 15th November Report; PDF page no. 19, line 21.
11 Hydro: Reliability and Resource Adequacy Study Review – 2023 Near-Term Reliability Report – 15th November Report; PDF page no. 26, line 12.
12 Hydro: Reliability and Resource Adequacy Study Review – 2023 Near-Term Reliability Report – 15th November Report; PDF page no. 27, line 3.
13 Hydro: Reliability and Resource Adequacy Study Review – 2023 Near-Term Reliability Report – 15th November Report; PDF page no. 28., line 2.
14 Newfoundland and Labrador Hydro - Concept Design Report Final Report; Hatch, 28 Sept. 2023; PDF Page numbers 21, 72.
15 The Hardwoods 50MW facility is on the same retirement schedule.

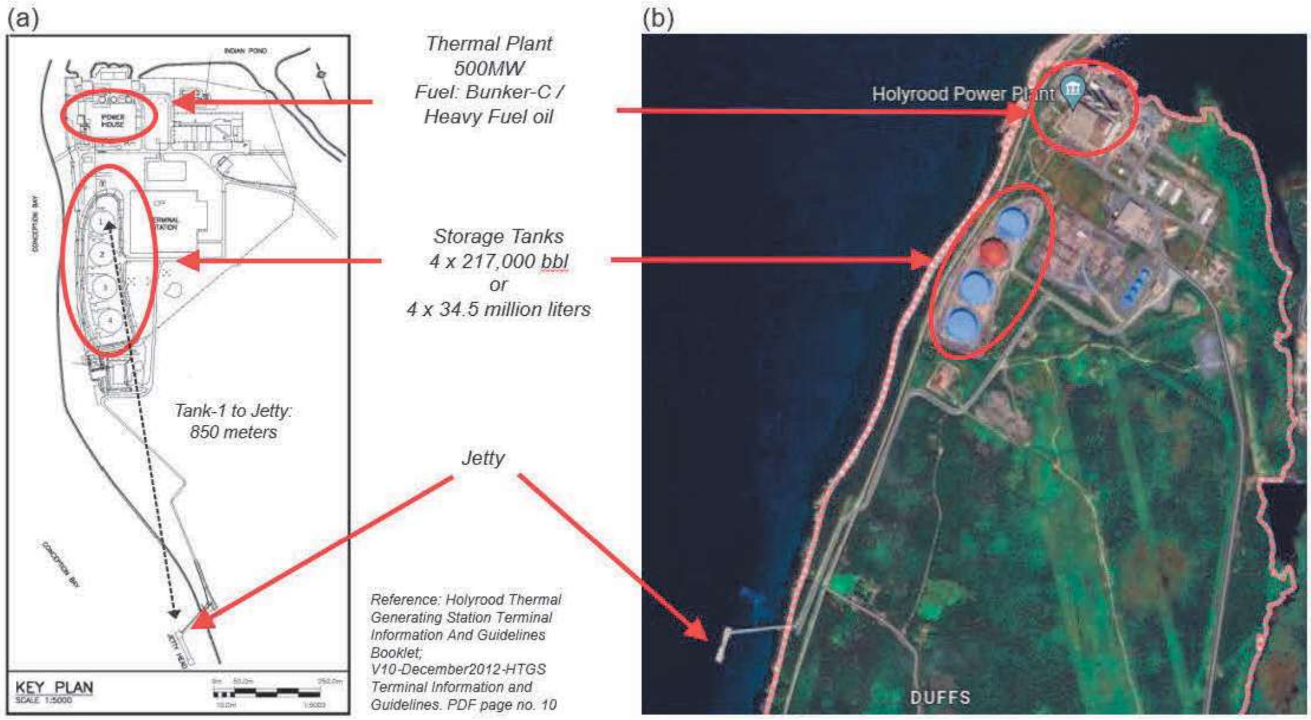


Figure 2 Holyrood Thermal Generating Station and Terminal

2.3 HOLYROOD GAS TURBINE(S)

The existing Holyrood gas turbine (GT) consumes approximately 969,000 liters per day at full load of No. 2 Diesel[16]. Assuming a similar fuel to MW ratio, the proposed 150MW turbine(s) would consume roughly 1.18 million liters of diesel per day; refer to Table 1 below for expected Fuel Consumption and Inventory Requirements at Holyrood for Gas Turbines.

[16] Newfoundland and Labrador Hydro - Concept Design Report Final Report; 28 Sept. 2023; PDF Page number 82.

(a) Diesel Consumption in One day (full load)

No	Description	Capacity (MW)	liters / day	Bbl. / day	kg / day
1	Holyrood gas turbine - existing [(a)]	123	969,000	6,095	823,650
2	Holyrood gas turbine - proposed	150	1,181,707	7,433	1,004,451
3	Total site capacity	273	2,150,707	13,528	1,828,101
4	*Holyrood gas turbine - future*	*300*	*2,363,415*	*14,865*	*2,008,902*
5	*Total site capacity*	*573*	*4,514,122*	*28,393*	*3,837,004*

Reference(s)
(a) Hatch report, 28th September 2023, PDF Page numbers 82

Barrels to liters	*158.99*
Diesel No. 2 density	*0.85*
Ratio: 123 MW : 969 kiloliters	*7,878*

(b) Holyrood Inventory Requirement (5 days)

No	Description	Capacity (MW)	Liters	Bbl.	Kg
1	Holyrood gas turbine - existing [(a)]	123	4,845,000	30,474	4,118,250
2	Holyrood gas turbine - proposed	150	5,908,537	37,164	5,022,256
3	Total site capacity	273	10,753,537	67,638	9,140,506
4	*Holyrood gas turbine - future*	*300*	*11,817,073*	*74,327*	*10,044,512*
5	*Total site capacity*	*573*	*22,570,610*	*141,965*	*19,185,018*

Assumption(s)	
Days	*5*

(c) Holyrood Inventory Value (5 days)

No	Description	Capacity (MW)	C$ Case-1	C$ Case-2
1	Holyrood gas turbine - existing [(a)]	123	7,267,500	8,280,105
2	Holyrood gas turbine - proposed	150	8,862,805	10,097,689
3	Total site capacity	273	16,130,305	18,377,794
4	*Holyrood gas turbine - future*	*300*	*17,725,610*	*20,195,378*
5	*Total site Value*	*573*	*33,855,915*	*38,573,172*
	Diesel price (assumption)	*C$ / liter*	*1.50*	*-*
	Irving; St Johns (279 Portugal Cove Rd), 14th March 2024	*C$ / liter*	*-*	*1.71*

Table 1 Fuel Consumption and Inventory Requirement at Holyrood (Gas Turbines)

Note: Whilst the additional diesel fuel requirements for expansion beyond the 150MW gas turbine at Holyrood was outside of the scope of this study, it was added to Table 1, Rows 4 and 5 as an item the study needed to be cognizant of when it came to reviewing the existing supply chain (Part-2 section 5 page 68) and critical assets (Part-3 section 6 page 88). Future additions at Holyrood have present day considerations as regards to which alternative fuel(s) are practical at Holyrood.

Consideration of the present turbine's utilization from 2015 to 2023, shows it generally well below 14% with a single excursion approaching 21% in 2016. Unpredictability of use impacts the supply chain (Table 2; Rows 7 and 8) and inventory management in terms of diesel stability and hence fuel quality.

No	Description	Units	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Operating Hours	hours	788	1,811	1,228	1,038	178	93	413	31	309
2	**Operating Days**	**days**	**33**	**75**	**51**	**43**	**7**	**4**	**17**	**1**	**13**
3	Percentage Utilization	%	9.0%	20.7%	14.0%	11.9%	2.0%	1.1%	4.7%	0.4%	3.5%
4	Fuel consumed	liters	13,276,144	26,358,691	24,954,656	21,233,897	4,084,699	1,978,072	8,948,316	689,476	6,138,125
5		barrels	83,505	165,791	156,960	133,557	25,692	12,442	56,283	4,337	38,608
6		tonnes	15,619	31,010	29,358	24,981	4,806	2,327	10,527	811	7,221
7	Deliveries - no. of truck loads	no.	214	425	402	342	66	32	144	11	99
8	Deliveries - no. of truck loads per 24 hours	no.	7	6	8	8	9	8	8	9	8

Reference(s)
NL Hydro data. See File of name 'HRDGT Operating Hrs and Fuel consumption'
(a) Hatch report, 28th September 2023, PDF Page numbers 79.

Barrels (liters)	*158.99*
Diesel No. 2	*0.85*
Factor	*1000.00*
Operating hours / annum	*8,760*
Fuel delivery (B-Train truck; liters)	*62,000*

Table 2 Fuel Consumption at Holyrood Gas Turbine (2015 to 2023)

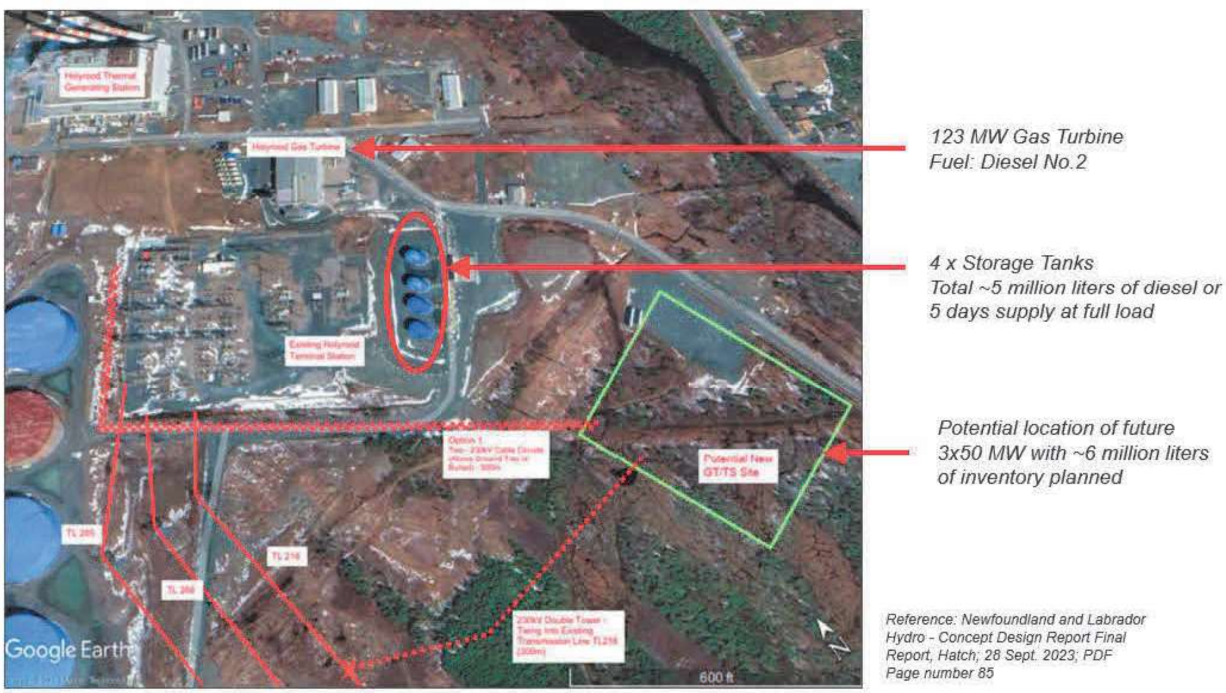


Figure 3 Holyrood Gas Turbine and Storage Tanks: current and proposed (3x50MW)

3 REPORT STRUCTURE

The report is structured as follows:

- Section 1: Executive Summary,
- Section 2: Introduction and Background,
- Section 3: Report Structure,
- Section 4: (Part 1) Market forecast and availability for No.2 Diesel,
- Section 5: (Part 2) Review existing client supply chain processes to identify risks and potential improvements,
- Section 6: (Part 3) Outline Any Critical Assets to the Total Supply Chain (from fuel producer to Hydro),
- Section 7: (Part 4) Provide outlook to alternative fuels sources (bio-fuel, hydrogen) and a potential timeline,
- Section 8: Summary: Key Findings, Strategic considerations, and Recommendations, and
- Section 9: Appendix.

4 PART 1: MARKET FORECAST AND AVAILABILITY FOR NO.2 DIESEL

The following provides an introductory overview of the Canadian and US refining industry as background to the production and supply / demand for diesel and renewable diesel. The information is presented as follows:

- Section 4.1: An Overview of Canada's Refining Sector
- Section 4.2: An Overview of US Refining Sector
- Section 4.3: Market Changes
- Section 4.4: Regulation in Canada
- Section 4.5: Regulation in US
- Section 4.6: Summary

4.1 AN OVERVIEW OF CANADA'S REFINING SECTOR

The following considers existing and conventional energy production, distribution, and supply infrastructure in Canada.

4.1.1 Commercial Production of Conventional Fuels in Canada

The number of operating refineries in Canada has declined from a high of 45 in 1960 to 13 currently, the trend is not unusual, is a function of competition within the sector, market forces, improved country wide logistics, increasing and achieving economies of scale resulting in consolidation or shutdowns. Refining capacity peaked in the 1980's but has declined slightly since to hover at ≈1.8 million barrels (bbl.) per day since; see Figure 4.

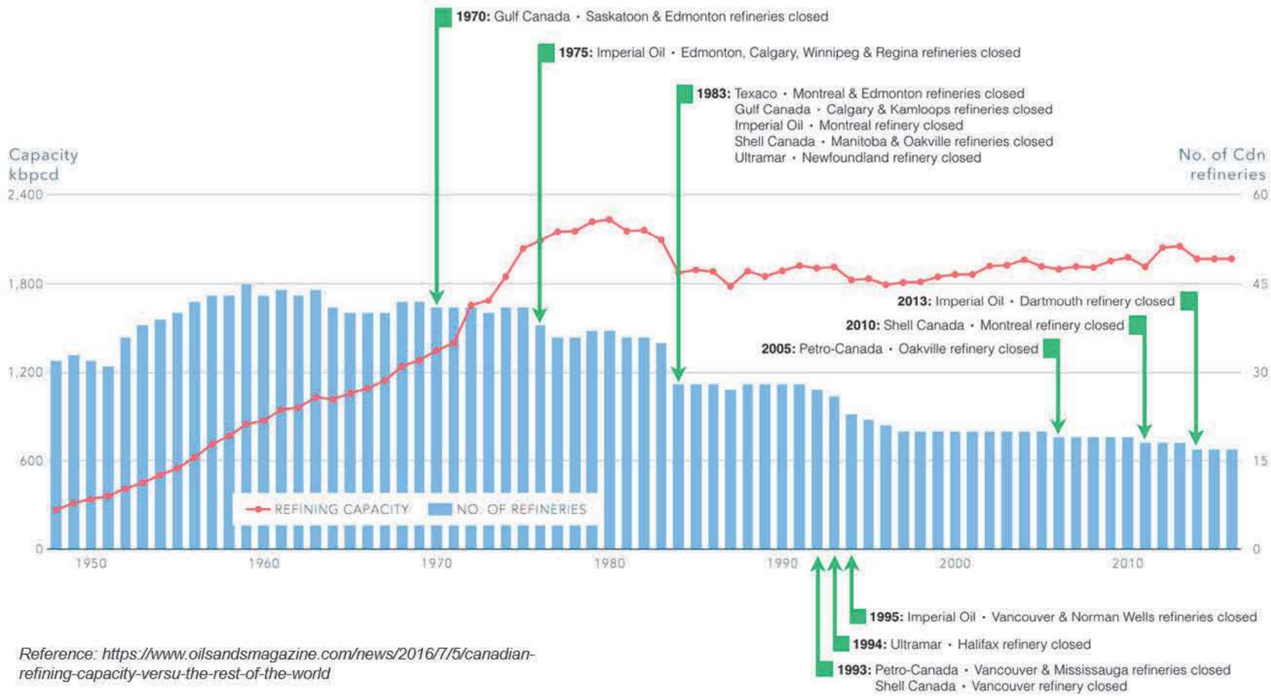


Figure 4 A Timeline of Canadian Refinery Capacity

The location of Canada's refineries is shown in Figure 5. Their locations are as function of:

- Immediate feedstock availability or for the need to access imported crude oil or products,
- Access to transport routes from a supply (crude oil imports) and distribution of marketable products via rail and waterway and
- Access to large local markets (within a primary 300-kilometer radius).

Cursory examination of refineries across the world will demonstrate most are located at or close to the coast or at least on waterways and rail routes. Those not in such locations, are located where they are for other factors, such as the ready availability of feedstock, an immediate domestic or at least nearby market that cannot be readily served by other producers.

Reference: https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/crude-oil-petroleum-products/report/2018-refinery-report/canadian-refinery-overview-2018-energy-market-assessment-canada-refineries.html?=undefined&wbdisable=true

Figure 5 Location of Canadian Refineries

Recent developments in Canada's traditional refining sector worth noting are:

- **1994 – 2023:** North Atlantic Refining (NARL) at Come-By-Chance experiences various changes of ownership.
- **June 2013**: Imperial Oil announces plans to close their 89,000 bpd Dartmouth Nova Scotia refinery and convert the site to a marine terminal[17].
- **March 2020:** The Come-by-Chance refinery is idled as fuel demand plummets during COVID[18].
- **May 2020**: Irving signals it is in negotiations to acquire and reopen idled Come-by-Chance[19].
- **October 2020:** The continued idling of the Come-By-Chance refinery (capacity 115,000 bpd - is announced following the collapse of a possible sale to Irving Oil[20].

---

[17] https://en.wikipedia.org/wiki/Dartmouth_Refinery
[18] https://financialpost.com/commodities/energy/first-north-american-refinery-shuts-with-fuel-demand-plunging
[19] https://www.cbc.ca/news/canada/newfoundland-labrador/refinery-irving-sale-1.5588017
[20] https://www.cbc.ca/news/canada/newfoundland-labrador/refinery-closing-irving-1.5751203

- **November 2021:** Cresta Fund Management acquires a controlling stake in NARL with the intention of converting the refinery to the production of renewable diesel and aviation fuel from used cooking oil, corn oil and animal fat; expected capacity - 14,000bpd[21].
  - The article reports the minority owner - Silverpeak – would continue to control NARL Marketing, the party responsible for importing conventional fuels into Newfoundland and Labrador and surrounds.
- **June 2023**: Irving Oil announces it will review its strategic direction; partial or complete sale of its St John, NB refinery (318,000bpd) is not ruled out[22].

Table 3 and Table 4 lists Canadian refineries currently operating along with their capacity in barrels and million liters per day respectively.

No	Province	Location	Ownership	Capacity (bbl / day)	Provincial Capacity (bbl / day)	% Split	Provincial Share
1	Alberta	Edmonton	Imperial Oil	187,000	429,000	10.7%	24.6%
2		Edmonton	Suncor Energy	142,000		8.2%	
3		Fort Saskatchewan	Shell Canada	100,000		5.7%	
4	British Columbia	Burnaby	Parkland Fuels	57,000	69,000	3.3%	4.0%
5		Prince George	Tidewater [(a)]	12,000		0.7%	
6	New Brunswick	Saint John	Irving Oil	318,000	318,000	18.3%	18.3%
7	Newfoundland and Labrador	*Come by Chance*	*North Atlantic Refining* [(b)]	*115,000*	*115,000*	-	-
8	Ontario	Sarnia	Imperial Oil	121,000	393,000	7.0%	22.6%
9		Nanticoke	Imperial Oil	112,000		6.4%	
10		Sarnia	Suncor Energy	85,000		4.9%	
11		Corunna	Shell Canada	75,000		4.3%	
12	Quebec	Levis	Valero	265,000	402,000	15.2%	23.1%
13		Montreal	Suncor Energy	137,000		7.9%	
14	Saskatchewan	Regina	Federated Co-operatives	130,000	130,000	7.5%	7.5%
15	**Total**	-	-	**1,741,000**	1,741,000	100.0%	100.0%

Reference(s)	*Stantec*
Note(s)	*(a) Tidewater: being converted to biodiesel - announced July, 2021*
	(b) 2021, Nov.: Cresta Fund Management acquire a controlling stake in NARL with the intention of converting Come-by-Chance to the production of renewable diesel and aviation; https://www.cbc.ca/news/canada/newfoundland-labrador/nl-north-atlantic-refinery-1.6267625

Table 3 Canadian Refineries – Location and Capacity (barrels)

[21] https://www.cbc.ca/news/canada/newfoundland-labrador/nl-north-atlantic-refinery-1.6267625
[22] https://atlantic.ctvnews.ca/irving-oil-weighing-its-options-including-the-possible-sale-of-its-assets-1.6431120

No	Province	Location	Ownership	Capacity (million liters / day)	Provincial Capacity (million liters / day)	% Split	Provincial Share
1	Alberta	Edmonton	Imperial Oil	29.28	67.18	10.7%	24.6%
2		Edmonton	Suncor Energy	22.24		8.2%	
3		Fort Saskatchewan	Shell Canada	15.66		5.7%	
4	British Columbia	Burnaby	Parkland Fuels	8.93	10.81	3.3%	4.0%
5		Prince George	Tidewater	1.88		0.7%	
6	New Brunswick	Saint John	Irving Oil	49.80	49.80	18.3%	18.3%
7	Newfoundland and Labrador	*Come by Chance*	*North Atlantic Refining*	*18.01*	*18.01*	-	-
8	Ontario	Sarnia	Imperial Oil	18.95	61.55	7.0%	22.6%
9		Nanticoke	Imperial Oil	17.54		6.4%	
10		Sarnia	Suncor Energy	13.31		4.9%	
11		Corunna	Shell Canada	11.75		4.3%	
12	Quebec	Levis	Valero	41.50	62.95	15.2%	23.1%
13		Montreal	Suncor Energy	21.45		7.9%	
14	Saskatchewan	Regina	Federated Co-operatives	20.36	20.36	7.5%	7.5%
15	**Total**	-	-	**272.65**	272.65	100.0%	100.0%

Reference(s)	*Stantec*

Table 4 Canadian Refineries – Location and Capacity (million liters)

Installed and historical operating capacity of the refineries is shown in Figure 6. Refinery utilization has hovered between 80% and slightly over 90% since 1997 to 2018, ranging between 1.5 and 1.8 million barrels of refined petroleum products manufactured per day.

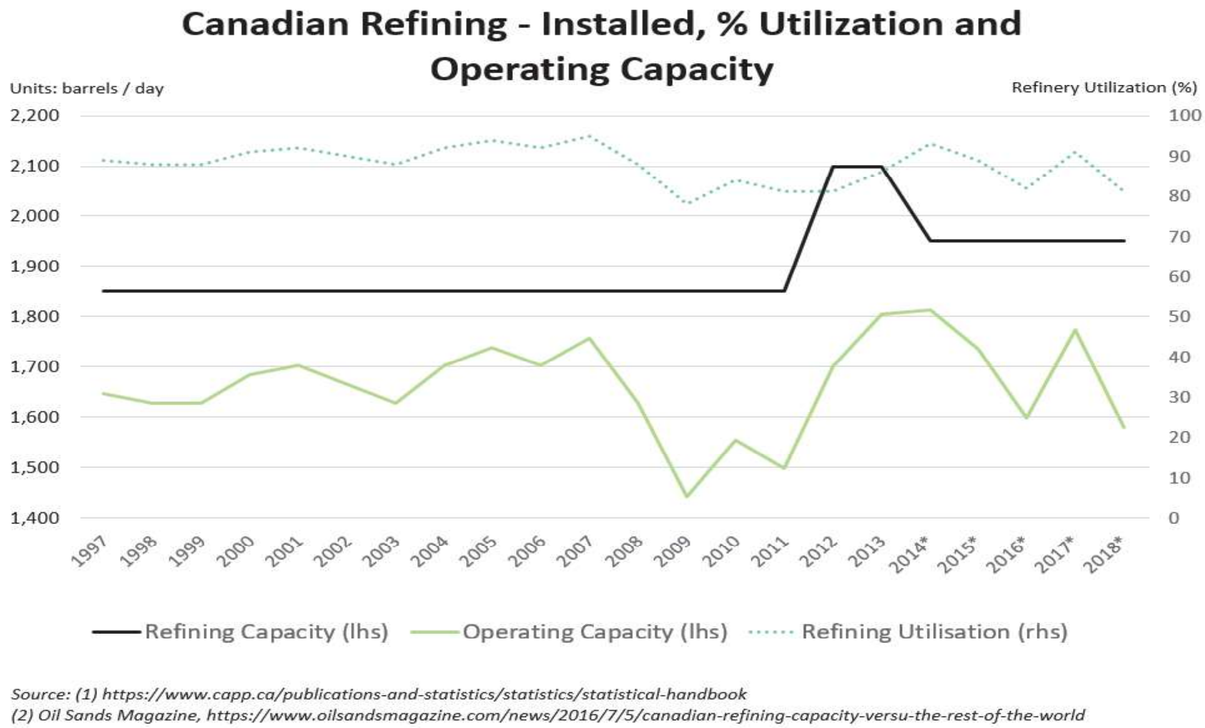


Figure 6 Canadian Conventional Refining - Installed, % Utilization and Operating Capacity

Primary products produced are gasoline, diesel, light and heavy oils, and aviation fuel in that order; Figure 7 and Figure 8.

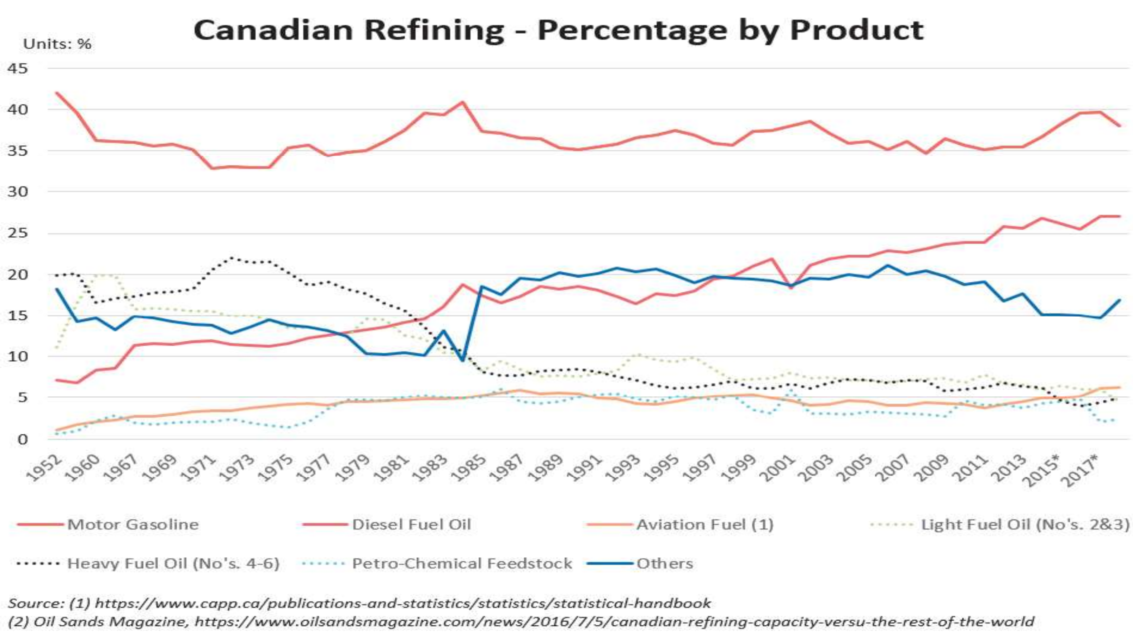


Figure 7 Canadian Refining - Percentage by Product

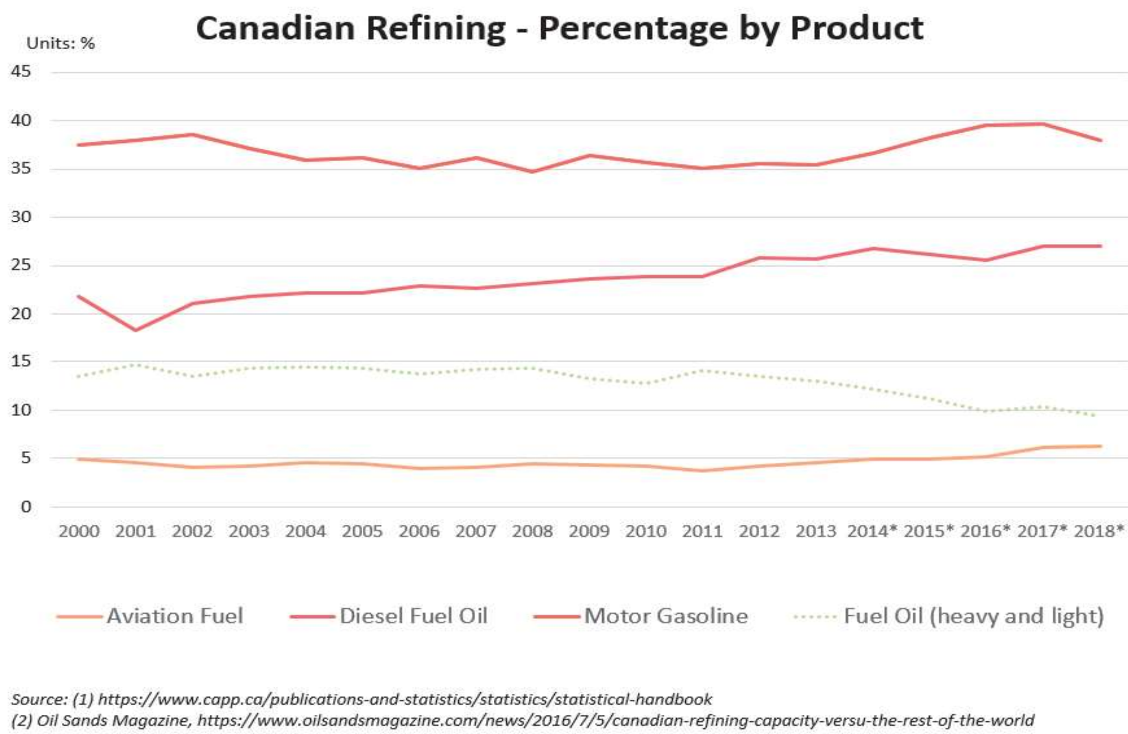


Figure 8 Canadian Refining - Percentage by Product (simplified)

Transport fuels are the dominant product from refining with <4% of refined product directed to the production of chemicals, Figure 9.

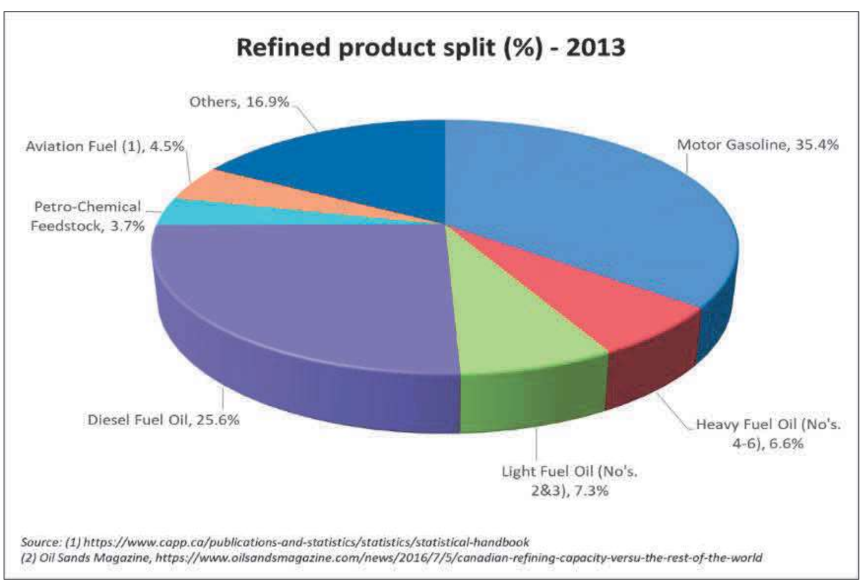


Figure 9 Canadian Refinery - Refined Products Split

Refining capacity by product has remained mostly flat since year 2000; per Figure 10. Such fluctuation as there is reflects global economic conditions such as the 2008 downturn extending to 2011.

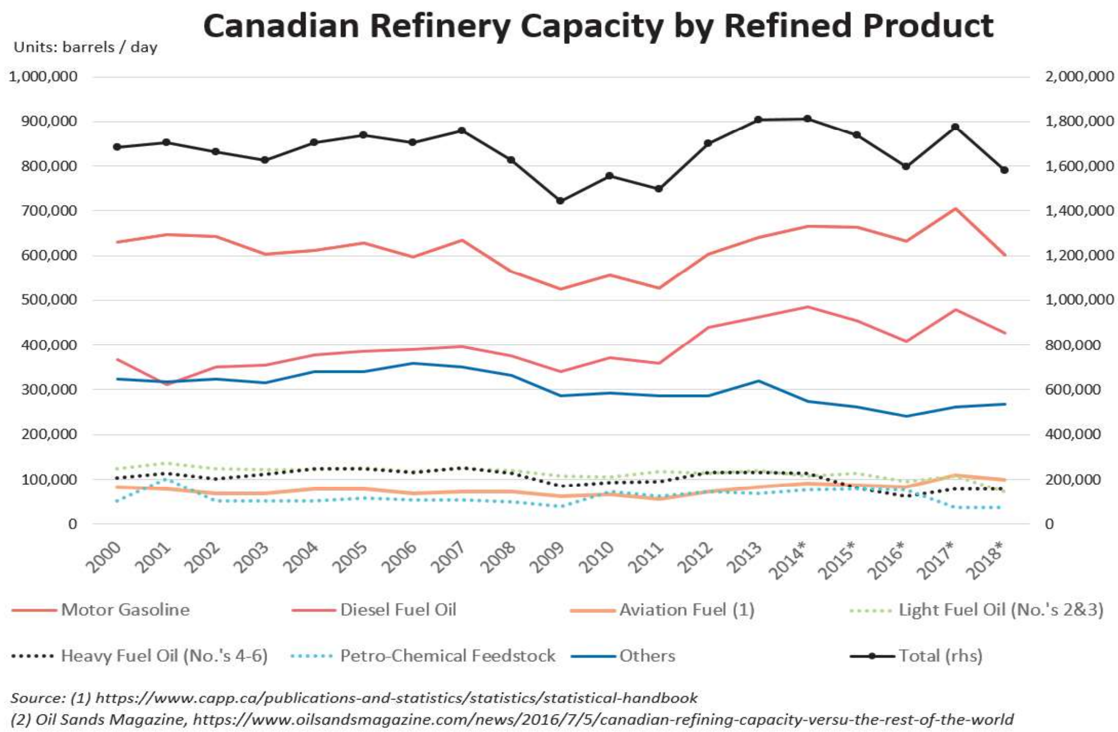


Figure 10 Canadian Conventional Refining Capacity by Product (bbls. / day)

Canadian refineries are focused on the production of transportation fuels such as diesel and automobile gasoline; Table 5 and Table 6 shows production for these products from year 2000 in barrels and liters per day. The ratio of gasoline to diesel produced has fluctuated across the period from a low of 0.48 to high of 0.73 and can be expected to be the result of more use of ethanol in the gasoline pool, as well as more diesel use in trucks and some cars. Diesel as a percentage of total refined product has fluctuated from 24% to 33%, gasoline from 47% to 50%. Hence 71% to 81% of product manufactured at Canadian refineries goes to road transportation fuels. Extrapolating from historical data, provides a rough production forecast for aviation fuel, diesel and gasoline; Figure 11.

Year	Diesel Fuel Oil	Motor Gasoline	Heavy Fuel Oil (No.'s 4-6)	Light Fuel Oil (No.'s 2&3)	Aviation Fuel	Total	Gasoline : Diesel ratio	Diesel %	Gasoline %	Total
2000	367,003	631,313	102,694	124,579	82,492	1,308,080	0.58	28.1%	48.3%	76.3%
2001	311,466	646,760	114,034	136,160	78,292	1,286,712	0.48	24.2%	50.3%	74.5%
2002	351,315	642,690	101,565	123,210	68,265	1,287,045	0.55	27.3%	49.9%	77.2%
2003	354,904	603,988	110,704	122,100	68,376	1,260,072	0.59	28.2%	47.9%	76.1%
2004	377,844	611,018	124,246	120,842	78,292	1,312,242	0.62	28.8%	46.6%	75.4%
2005	386,058	627,779	123,469	125,208	78,255	1,340,769	0.61	28.8%	46.8%	75.6%
2006	389,758	597,402	115,736	117,438	68,080	1,288,414	0.65	30.3%	46.4%	76.6%
2007	397,195	634,458	126,540	123,025	72,058	1,353,275	0.63	29.4%	46.9%	76.2%
2008	376,068	564,916	113,960	118,844	71,632	1,245,420	0.67	30.2%	45.4%	75.6%
2009	340,548	525,252	83,694	106,782	62,049	1,118,325	0.65	30.5%	47.0%	77.4%
2010	371,406	554,778	93,240	105,672	65,268	1,190,364	0.67	31.2%	46.6%	77.8%
2011	358,142	525,974	94,406	116,883	55,445	1,150,848	0.68	31.1%	45.7%	76.8%
2012	438,858	603,855	115,668	113,967	71,442	1,343,790	0.73	32.7%	44.9%	77.6%
2013	462,896	640,046	115,819	119,304	81,523	1,419,588	0.72	32.6%	45.1%	77.7%
2014*	486,036	665,282	113,108	108,212	89,768	1,462,406	0.73	33.2%	45.5%	78.7%
2015*	453,469	662,787	80,284	113,207	86,619	1,396,366	0.68	32.5%	47.5%	79.9%
2016*	407,745	631,605	62,361	95,940	83,148	1,280,799	0.65	31.8%	49.3%	81.1%
2017*	479,115	704,477	78,078	106,470	110,019	1,478,159	0.68	32.4%	47.7%	80.1%
2018*	426,684	600,518	77,435	71,114	99,560	1,275,310	0.71	33.5%	47.1%	80.5%

Reference:	*Source: (1) https://www.capp.ca/publications-and-statistics/statistics/statistical-handbook* *(2) Oil Sands Magazine, https://www.oilsandsmagazine.com/news/2016/7/5/canadian-refining-capacity-versu-the-rest-of-the-world*

Table 5 Canadian Production of Transportation Fuels (Units: barrels per day)

Year	Diesel Fuel Oil	Motor Gasoline	Heavy Fuel Oil (No.'s 4-6)	Light Fuel Oil (No.'s 2&3)	Aviation Fuel	Total	Gasoline : Diesel ratio	Diesel %	Gasoline %	Total
2000	58.35	100.37	16.33	19.81	13.12	208	0.58	28.1%	48.3%	76.3%
2001	49.52	102.83	18.13	21.65	12.45	205	0.48	24.2%	50.3%	74.5%
2002	55.85	102.18	16.15	19.59	10.85	205	0.55	27.3%	49.9%	77.2%
2003	56.43	96.03	17.60	19.41	10.87	200	0.59	28.2%	47.9%	76.1%
2004	60.07	97.14	19.75	19.21	12.45	209	0.62	28.8%	46.6%	75.4%
2005	61.38	99.81	19.63	19.91	12.44	213	0.61	28.8%	46.8%	75.6%
2006	61.97	94.98	18.40	18.67	10.82	205	0.65	30.3%	46.4%	76.6%
2007	63.15	100.87	20.12	19.56	11.46	215	0.63	29.4%	46.9%	76.2%
2008	59.79	89.81	18.12	18.89	11.39	198	0.67	30.2%	45.4%	75.6%
2009	54.14	83.51	13.31	16.98	9.87	178	0.65	30.5%	47.0%	77.4%
2010	59.05	88.20	14.82	16.80	10.38	189	0.67	31.2%	46.6%	77.8%
2011	56.94	83.62	15.01	18.58	8.81	183	0.68	31.1%	45.7%	76.8%
2012	69.77	96.01	18.39	18.12	11.36	214	0.73	32.7%	44.9%	77.6%
2013	73.59	101.76	18.41	18.97	12.96	226	0.72	32.6%	45.1%	77.7%
2014*	77.27	105.77	17.98	17.20	14.27	233	0.73	33.2%	45.5%	78.7%
2015*	72.10	105.37	12.76	18.00	13.77	222	0.68	32.5%	47.5%	79.9%
2016*	64.83	100.42	9.91	15.25	13.22	204	0.65	31.8%	49.3%	81.1%
2017*	76.17	112.00	12.41	16.93	17.49	235	0.68	32.4%	47.7%	80.1%
2018*	67.84	95.47	12.31	11.31	15.83	203	0.71	33.5%	47.1%	80.5%

Reference:	*Source: (1) https://www.capp.ca/publications-and-statistics/statistics/statistical-handbook* *(2) Oil Sands Magazine, https://www.oilsandsmagazine.com/news/2016/7/5/canadian-refining-capacity-versu-the-rest-of-the-world*

Table 6 Canadian Production of Transportation Fuels (Units: million liters per day)

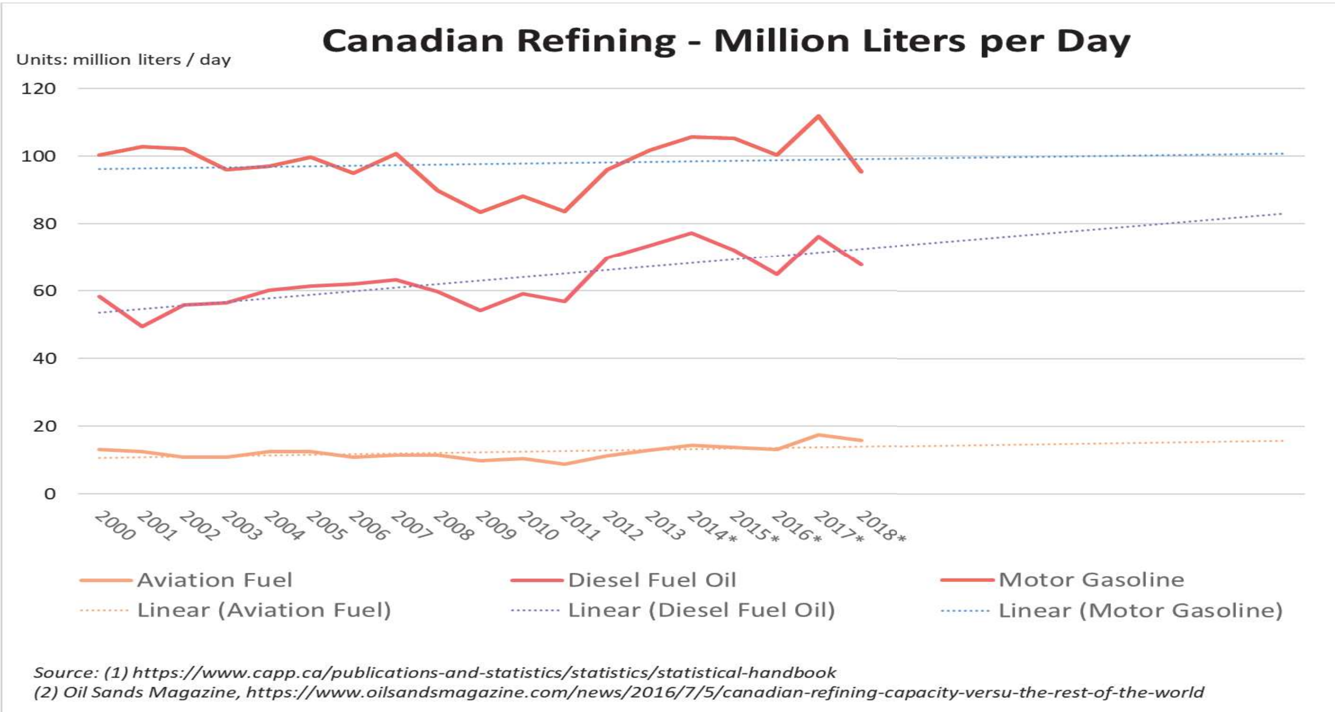


Figure 11 Canadian Conventional Refining Capacity by Product (million liters / day)

Diesel, gasoline, fuel (or heating) oils along with aviation fuels are produced and distributed in Canada by the companies shown in Figure 12. All are of long standing and in their own right, form hubs or clusters of allied supporting industries into distribution culminating at retail sales.

Figure 12 Canadian Fuels Association Members

4.1.2 Commercial Production of Unconventional Green Fuels in Canada

The production of unconventional fuels in Canada is driven by Federal and Provincial policy. Table 7 and Table 8 provide historical minimum blending mandates adopted for diesel and gasoline, respectively. Figure 13 depicts the mandates graphically across the country from west to east coast with a capacity forecast from Advanced Biofuels Canada; Figure 14.

The distinction between biodiesel and renewable diesel is dealt with in section 7.4.1 page 100. Production of biodiesel, renewable diesel and ethanol are discussed in sections 4.1.2.1 and 4.1.2.2 below respectively.

No	Region	2010	2011	2012 & 13	2014 & 15	2016	2017 to 2020	2021
1	British Columbia	3.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
2	Alberta	-	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
3	Saskatchewan	-	-	2.0%	2.0%	2.0%	2.0%	2.0%
4	Manitoba	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
5	Ontario	-	-	-	2.0%	3.0%	4.0%	4.0%
6	Canada	-	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

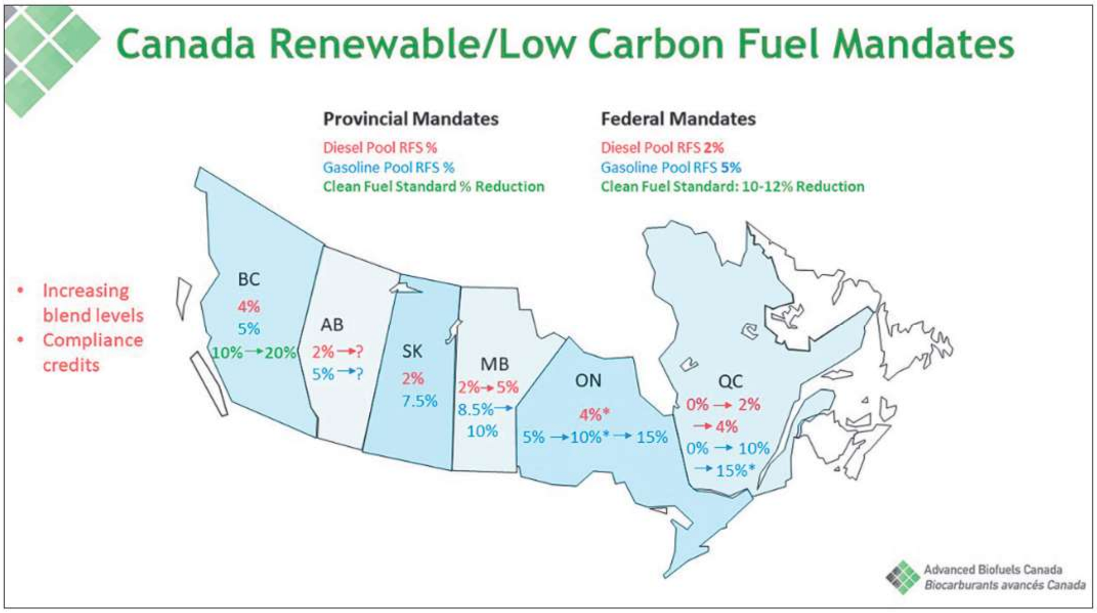
Reference(s)
Tracking Biofuel Consumption, feedstocks and avoided Greenhouse Gas Emissions, Nov. 2021, Navius Research. PDF page no. 13

Table 7 Diesel – biodiesel blending mandate

No	Region	2010	2011 to 2019
1	British Columbia	5.0%	5.0%
2	Alberta	-	5.0%
3	Saskatchewan	7.5%	7.5%
4	Manitoba	8.5%	8.5%
5	Ontario	5.0%	5.0%
6	Canada	-	5.0%

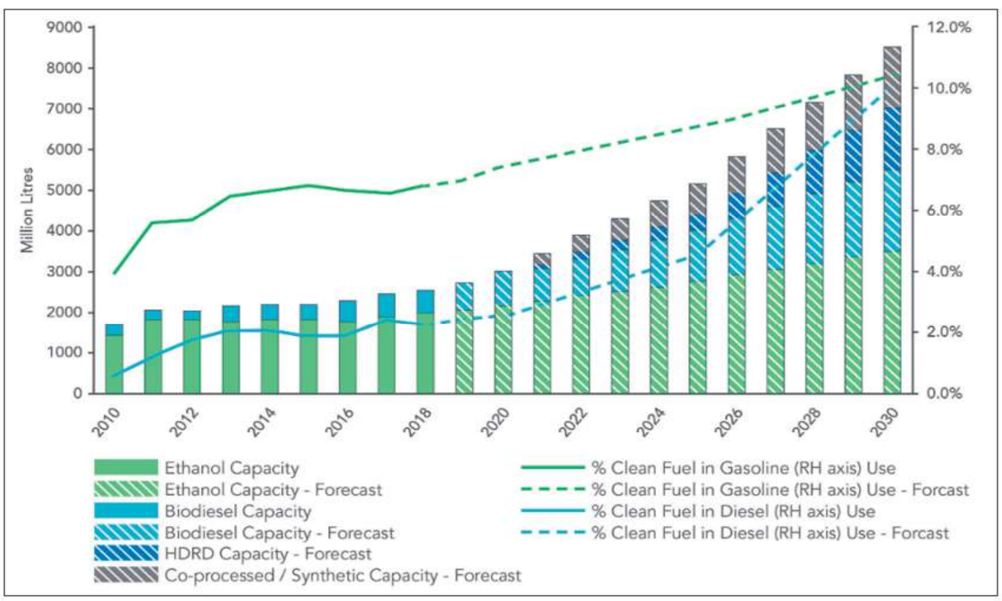
Reference(s)
Tracking Biofuel Consumption, feedstocks and avoided Greenhouse Gas Emissions, Nov. 2021, Navius Research. PDF page no. 13

Table 8 Gasoline – Ethanol Blending Mandate



Reference: Advanced Biofuels Canada; https://advancedbiofuels.ca/policy/#

Figure 13 Canada's Renewable / Low Carbon Fuel Mandates



Reference: Advanced Biofuels Canada; https://advancedbiofuels.ca/policy/#

Figure 14 Biofuels Canada – Capacity Forecast

4.1.2.1 Biodiesel and Renewable Diesel

The distinction between bio- and renewable diesel is covered in section 7.4.1 page 100.

Biodiesel in Canada is produced at the facilities listed in Table 9. Canada's traditional refineries in 2018 produced 426,600 barrels / day of conventional diesel (Table 5 page 16) whereas the installed operating capacity for biodiesel was ≈12,000 bbl. per day or 2.8 % of the former. This figure is expected to rise by an additional ≈70,000 barrels per day with announcement of new investment in renewable diesel; see Table 10 for Renewable Diesel Facilities in Canada.

No	Name	Location	Province	Capacity (million liters / year)	Feedstock	Capacity (barrels)	Capacity (bbl. / day)	Capacity (liters / day)	Remarks	Notes
1	ADM	Lloydminster	Saskatchewan	265	Canola	1,666,667	4,902	779,412	*Startup 2013*	-
2	Verbo Diesel Canada (formerly Atlantic Biodiesel)	Welland	Ontario	170	Canola, soybean	1,069,182	3,145	500,000	-	-
3	Canary Biofuels (formerly Invigor Bioenergy Corp, formerly Kyoto Fuels Corp)	Lethbridge	Alberta	66	Canola, animal tallow	415,094	1,221	194,118	*Developed in ≈2012. Operating status uncertain*	-
4	Consolidated Biofuels Ltd.	Delta	British Columbia	11	Yellow grease	69,182	203	32,353	*Operating status uncertain*	-
5	INNOLTEK (formerly QFI Biodiesel)	St-Jean-d'Iberville	Quebec	10	Multi-feedstock	62,893	185	29,412	*Operating status uncertain*	-
6	Methes Energies Canada Inc.	Mississauga	Ontario	5	Yellow grease	31,447	92	14,706	*Closed in 2015*	(a)
7	Methes Energies Canada Inc.	Sombra	Ontario	50	Multi-feedstock	314,465	925	147,059	*Acquired by BIOX 2015*	(b)
8	Milligan Bio-Tech Inc.	Foam Lake	Saskatchewan	20	Canola	125,786	370	58,824	*In receivership - 2018*	(c)
9	Noroxel Energy Ltd.	Springfield	Ontario	5	Yellow grease	31,447	92	14,706	*Operating status uncertain*	-
10	Rothsay Biodiesel	Montreal	Quebec	55	Multi-feedstock	345,912	1,017	161,765	*Closed in 2021*	(d)
11	World Energy (formerly BIOX Corp)	Hamilton	Ontario	66	Multi-feedstock	415,094	1,221	194,118	*Operating*	-
12	**Total**			**723**		**4,547,170**	**13,374**	**2,126,471**		
13	**Total (adjusted)**			**663**		**4,169,811**	**12,264**	**1,950,000**		

Reference / Notes	
	https://ricanada.org/industry-map/; Biodiesel Magazine (http://www.biodieselmagazine.com/plants/listplants/Canada/)
	(a) http://www.biodieselmagazine.com/articles/365137/mississauga-biodiesel-equipment-shipped-to-havelock-ontario
	(b) https://www.canadianmanufacturing.com/manufacturing/biox-buys-idle-sarnia-ont-biodiesel-plant-from-methes-energies-for-us4-5m-170415/
	(c) https://www.realagriculture.com/2018/02/milligan-biofuels-enters-receivership/
	(d) https://www.biobased-diesel.com/post/darling-ingredients-closes-2-biodiesel-plants-in-us-canada-with-no-plans-to-reopen#:~:text=Darling%20Ingredients%20released%20its%20Q4,Griffin%20Industries%20renamed%20Darling%20Ingredients).

Table 9 Biodiesel Facilities in Canada - Operating

No	Name	Location	Province	Capacity (million liters / year)	Feedstock	Capacity (barrels)	Capacity (barrels / day)	Capacity (liters / day)	Remarks	Notes
1	Braya Renewables	Come-By-Chance	Newfoundland and Labrador	757	Multi-feedstock	4,760,000	14,000	2,226,000	*Announced 2021, Nov.*	(a)
2	Covenant Energy Ltd.	Estevan	Saskatchewan	325	Canola	2,044,025	6,012	955,882	*Announced 2021, Mar.*	(b)
3	Federated Co-operatives Limited	Regina	Saskatchewan	1,000	Canola	6,289,308	18,498	2,941,176	*Announced 2021, Apr.*	(c)
4	Forge Hydrocarbons	Sombra	Ontario	28	Multi-feedstock	178,553	525	83,500	*Announced 2020*	(d)
5	Imperial Oil	Fort Saskatchewan	Alberta	984	Canola	6,190,000	18,206	2,894,735	*Announced 2021, Aug.*	(e)
6	Parkland Corp.	Burnaby	British Columbia	649	*(aa)*	4,080,000	12,000	1,908,000	*Announced 2022, May*	(f)
7	Refuel Energy	*(aa)*	Southern Ontario	162	Multi-feedstock	1,020,000	3,000	477,000	*Announced 2022, Apr.*	(g)
8	Tidewater	Prince George	British Columbia	649	Canola	4,080,000	12,000	1,908,000	*Announced 2021, Apr.*	(h)
9	**Total**			**4,554**		**23,881,887**	**70,241**	**11,168,294**		

(aa) not determined

Reference / Notes
https://ricanada.org/industry-map/; Biodiesel Magazine (http://www.biodieselmagazine.com/plants/listplants/Canada/)
(a) https://www.saltwire.com/atlantic-canada/business/end-to-uncertainty-biofuel-future-for-come-by-chance-gives-new-hope-for-workers-at-idle-refinery-100664831/; https://www.cbc.ca/news/canada/newfoundland-labrador/refinery-leadership-braya-1.6344695
(b) https://www.covenantenergy.ca/2021/03/18/covenant-energy-prepares-to-meet-new-demand-for-renewable-diesel/
(c) https://www.producer.com/news/fcl-takes-on-renewable-diesel-project/
(d) https://www.canadianbiomassmagazine.ca/forge-hydrocarbons-to-build-30m-biofuel-plant-in-ontario/
(e) https://news.imperialoil.ca/news-releases/news-releases/2021/Imperial-to-produce-renewable-diesel-at-Strathcona-refinery/default.aspx
(f) https://www.canadianbiomassmagazine.ca/parkland-plans-to-build-bcs-largest-renewable-diesel-complex/
(g) http://www.biodieselmagazine.com/articles/2518094/refuel-energy-announces-plans-for-ontario-biorefinery
(h) https://www.myprincegeorgenow.com/144624/news/tidewater-midstream-plans-to-build-canadas-first-renewable-diesel-facility-in-pg/

Table 10 Renewable Diesel Facilities in Canada – Publicly Announced

The technologies deployed in the above listed facilities are provided in Table 11 and Table 12.

No	Name	Location	Province	Feedstock	Remarks	Technology	Product(s)
1	ADM	Lloydminster	Saskatchewan	Canola	*Startup 2013*	*Esterification* [(a)]	*FAME, glycerol (raw)*
2	Verbo Diesel Canada (formerly Atlantic Biodiesel)	Welland	Ontario	Canola, soybean	-	Esterification	FAME, glycerol (raw)
3	Canary Biofuels (formerly Invigor Bioenergy Corp, formerly Kyoto Fuels Corp)	Lethbridge	Alberta	Canola, animal tallow	*Developed in ≈2012. Operating status uncertain*	Esterification	FAME, glycerol (raw)
4	Consolidated Biofuels Ltd.	Delta	British Columbia	Yellow grease	*Operating status uncertain*	Esterification	FAME, glycerol (raw)
5	INNOLTEK (formerly QFI Biodiesel)	St-Jean-d'Iberville	Quebec	Multi-feedstock	*Operating status uncertain*	Esterification	FAME, glycerol (raw)
6	Methes Energies Canada Inc.	Mississauga	Ontario	Yellow grease	*Closed in 2015*	closed	-
7	Methes Energies Canada Inc.	Sombra	Ontario	Multi-feedstock	*Acquired by BIOX 2015*	Status undermined	-
8	Milligan Bio-Tech Inc.	Foam Lake	Saskatchewan	Canola	*In receivership - 2018*	In receivership - 2018	-
9	Noroxel Energy Ltd.	Springfield	Ontario	Yellow grease	*Operating status uncertain*	-	-
10	Rothsay Biodiesel	Montreal	Quebec	Multi-feedstock	*Closed in 2021*	closed	-
11	World Energy (formerly BIOX Corp)	Hamilton	Ontario	Multi-feedstock	*Operating*	*Esterification* [(a)]	*FAME, glycerol (raw)*

(a) not verified

Reference(s)	*Stantec - business intelligence gathering / various public sources*

Table 11 Biodiesel Production Technology - Operating Plant

No	Name	Location	Province	Feedstock	Technology	Product(s)	Notes
1	Braya Renewables	Come-By-Chance	Newfoundland and Labrador	Multi-feedstock	*Undetermined / not announced*	Renewable Diesel SAF	(a)
2	Covenant Energy Ltd.	Estevan	Saskatchewan	Canola oil	HDRD (Haldor Topsøe)	Renewable Diesel SAF (?)	(b)
3	FCL	Regina	Saskatchewan	Canola oil	*Undetermined / not announced*	Renewable Diesel SAF (?)	(c)
4	Forge Hydrocarbons	Sombra	Ontario	Multi-feedstock	Lipid-to-Hydrocarbons (proprietary)	Renewable Diesel	(d)
5	Imperial Oil	Fort Saskatchewan	Alberta	Canola oil	*HDRD* [(a)]	*Renewable Diesel SAF (?)*	(e)
6	Parkland Corp.	Burnaby	British Columbia	Multi-feedstock	*Undetermined / not announced*	*Renewable Diesel SAF (?)*	(f)
7	Refuel Energy	*(aa)*	Southern Ontario	Multi-feedstock	HDRD (Haldor Topsøe)	Renewable Diesel SAF (?)	(g)
8	Tidewater	Prince George	British Columbia	Canola oil	HDRD (Haldor Topsøe)	Renewable Diesel SAF (?)	(h)

(aa) not verified or determined; assumption

Reference / Notes
(a) https://www.saltwire.com/atlantic-canada/business/end-to-uncertainty-biofuel-future-for-come-by-chance-gives-new-hope-for-workers-at-idle-refinery-100664831/; https://www.cbc.ca/news/canada/newfoundland-labrador/refinery-leadership-braya-1.6344695
(b) https://www.covenantenergy.ca/2021/03/18/covenant-energy-prepares-to-meet-new-demand-for-renewable-diesel/
(c) https://www.producer.com/news/fcl-takes-on-renewable-diesel-project/
(d) https://www.canadianbiomassmagazine.ca/forge-hydrocarbons-to-build-30m-biofuel-plant-in-ontario/
(e) https://news.imperialoil.ca/news-releases/news-releases/2021/Imperial-to-produce-renewable-diesel-at-Strathcona-refinery/default.aspx
(f) https://www.canadianbiomassmagazine.ca/parkland-plans-to-build-bcs-largest-renewable-diesel-complex/
(g) http://www.biodieselmagazine.com/articles/2518094/refuel-energy-announces-plans-for-ontario-biorefinery
(h) https://www.myprincegeorgenow.com/144624/news/tidewater-midstream-plans-to-build-canadas-first-renewable-diesel-facility-in-pg/

Table 12 Renewable Diesel Production Technology – New Plant

A concept in comparatively early development and falling within the definition of renewable diesel, is that of synthetic paraffinic kerosene (SPK) produced from green-H_2 and carbon dioxide in a reverse water-gas shift to produce syngas, and then Fischer-Tropsch (FT) synthesis to produce renewable / (bio)diesel and SAF. The concept is interesting, but current technical[23] and economic[24] barriers to commercialization remain high to the extent that when compared to the development history of existing commercial FT

[23] Fischer-Tropsch derived diesel is not a fungible - directly marketable diesel - it has a lower density than road diesel.

[24] Fischer-Tropsch plants are an assembly of integrated licensed technologies that typically carry a notably to significant higher cost than a standard crude oil refinery. More on the history and challenges of synthetic fuels can be found in Section 7.4.6 page 114.

companies, this variant could be years or decades from broad commercialization where it makes economic sense.

4.1.2.2 Ethanol

There are 14 facilities and slightly less companies scattered across Canada that have a total installed capacity of 1,843 million liters per year or 11.2 million barrels/year of first generation (1G) technology; per Table 13. Assuming 340 operating days a year this translates to roughly 33,000 bbl. or 5.2 million liters of ethanol per day. Production is principally via 1st generation (1G) technology (fermentation and distillation) from corn and wheat, some from alternative crops, and only Tembec utilizing forestry biomass. The latter suggests 2nd generation (2G) technology based on fermentation of non-food feedstocks (agricultural / forest residues) has yet to mature to the extent necessary to be of commercial relevance.

At provincial level, Ontario leads with 63% of the country's production capacity with remaining provinces producing between 7 and 11%; per Table 14. Canada in contrast to the USA has considerably less capacity - 1.84 billion liters per year versus 66.3 billion liters per year. On a per capita basis – this translates to 49 versus 197 liters per capita; per Table 15.

No	Name	Location	Province	Capacity (mmgy)	Capacity (million liters)	Feedstock	Capacity (barrels)	Capacity (barrels / day)	Capacity (tons)	Capacity (tons / day)	Capacity liters / day
1	Future Fuel	Hairy Hill	AB	11	40	Wheat	251,572	740	31,320	92	117,647
2	Husky Energy	Lloydminster	AB	34	130	Wheat	817,610	2,405	101,790	299	382,353
3	Permolex International (API Grain Processors)	Red Deer	AB	11	42	Wheat, wheat starch, corn, barley, rye & triticale	264,151	777	32,886	97	123,529
4	Husky Energy	Minnedosa	MB	34	130	Wheat, corn	817,610	2,405	101,790	299	382,353
5	Suncor	St. Clair	ON	106	400	Corn	2,515,723	7,399	313,200	921	1,176,471
6	Greenfield Global Inc.	Chatham	ON	52	195	Corn	1,226,415	3,607	152,685	449	573,529
7	Greenfield Global Inc.	Johnstown	ON	66	250	Corn	1,572,327	4,624	195,750	576	735,294
8	Greenfield Global Inc.	Tiverton	ON	7	27	Corn	169,811	499	21,141	62	79,412
9	IGPC Ethanol	Aylmer	ON	45	172	Corn	1,081,761	3,182	134,676	396	505,882
10	Kawartha Ethanol	Havelock	ON	21	80	Corn	503,145	1,480	62,640	184	235,294
11	Greenfield Global Inc.	Varennes	QE	46	175	Corn	1,100,629	3,237	137,025	403	514,706
12	Tembec (Rayonier Advanced Materials)	Temiscaming	QE	4	17	Forestry	106,918	314	13,311	39	50,000
13	Noramera Bioenergy Corp	Weyburn,	SK	7	25	Corn / wheat	157,233	462	19,575	58	73,529
14	Pound-Maker Agventures, Ltd.	Lanigan	SK	4	15	Wheat	94,340	277	11,745	35	44,118
15	Terra Grain Fuels (FCL / CO-OP owned)	Belle Plaine	SK	40	150	Wheat	943,396	2,775	117,450	345	441,176
16	**Total**			**488**	**1,848**		**11,371,069**	**33,444**	**1,415,664**	**4,164**	**5,435,294**
17	Canada population (2018)			million	37						
18	Consumption			liter / capita	50						

Reference(s)	https://ricanada.org/industry-map/

Table 13 Ethanol (1G) Production in Canada

No	Province	Capacity (million liters)	Provincial Split (%)	Capacity (barrels)	Capacity (barrels / day)	Capacity (tons)	Capacity (tons / day)
1	Alberta	212	11%	1,333,333	3,922	165,996	488
2	Manitoba	130	7%	817,610	2,405	101,790	299
3	Ontario	1,124	61%	4,993,711	14,687	621,702	1,829
4	Quebec	192	10%	106,918	314	13,311	39
5	Saskatchewan	190	10%	1,037,736	3,052	129,195	380
6	Total	1,848	100%	8,289,308	24,380	1,031,994	3,035

Reference(s)	
	https://ricanada.org/industry-map/

Table 14 Ethanol Production in Canada by Province

No	Desription	Unit	Value
1	Canada	Capacity (million liters)	1,823
2	Canada population (2018)	million	37
3	Consumption	liter / capita	49
4			
5	USA	Capacity (million liters)	64,257
6	USA population (2018)	million	327
7	Comsumption	liter / capita	197

References
https://ricanada.org/industry-map/
https://www.naics.com/naics-code-description/?code=325193
http://www.hoovers.com/company-information/company-search.html?nvind=1822&maxitems=25&page=2
http://ethanolproducer.com/plants/map/

Table 15 Ethanol Consumption per Capita – Canada versus USA

4.1.2.3 Blend Availability

Based on the volume of diesel and gasoline[25] produced per Table 5 and Table 6, and with a Canadian blend mandate of 2% renewable diesel and 5% ethanol, the annual demand for these two components falls in the region of:

- Renewable diesel: ≈8,500 bbl. / day or ≈1.4 million liters / day, and
- Ethanol: ≈30,000 bbl. / day or ≈4.8 million liters / day; Table 16 and Table 17.

Announced production, and existing capacity for renewable diesel and ethanol respectively are as follows:

- Renewable diesel: ≈70,000 bbl. / day; Table 10 page 25 and
- Ethanol: ≈33,000 bbl. / day; Table 13 page 29.

[25] Whilst the focus of this report is diesel as opposed to gasoline, this section includes comment to gasoline, as electrification of the vehicle pool would / will impact the demand for gasoline and ethanol in turn; and ethanol conceptually could be an alternative fuel at Holyrood.

The above suggests that for both diesel and gasoline with all factors being equal, adequate volumes of renewables should be available.

Year	Diesel Fuel Oil	Motor Gasoline	Diesel Fuel Oil	Ethanol
2000	367,003	631,313	7,340	31,566
2001	311,466	646,760	6,229	32,338
2002	351,315	642,690	7,026	32,135
2003	354,904	603,988	7,098	30,199
2004	377,844	611,018	7,557	30,551
2005	386,058	627,779	7,721	31,389
2006	389,758	597,402	7,795	29,870
2007	397,195	634,458	7,944	31,723
2008	376,068	564,916	7,521	28,246
2009	340,548	525,252	6,811	26,263
2010	371,406	554,778	7,428	27,739
2011	358,142	525,974	7,163	26,299
2012	438,858	603,855	8,777	30,193
2013	462,896	640,046	9,258	32,002
2014*	486,036	665,282	9,721	33,264
2015*	453,469	662,787	9,069	33,139
2016*	407,745	631,605	8,155	31,580
2017*	479,115	704,477	9,582	35,224
2018*	426,684	600,518	8,534	30,026

Description	*Diesel*	*Gasoline*
Assumption (blending mandate)	*2%*	*5%*

Table 16 Renewable Diesel and Ethanol Demand; Units: barrels / day

Year	Diesel Fuel Oil	Motor Gasoline	Diesel Fuel Oil	Ethanol
2000	58.35	100.37	1.17	5.02
2001	49.52	102.83	0.99	5.14
2002	55.85	102.18	1.12	5.11
2003	56.43	96.03	1.13	4.80
2004	60.07	97.14	1.20	4.86
2005	61.38	99.81	1.23	4.99
2006	61.97	94.98	1.24	4.75
2007	63.15	100.87	1.26	5.04
2008	59.79	89.81	1.20	4.49
2009	54.14	83.51	1.08	4.18
2010	59.05	88.20	1.18	4.41
2011	56.94	83.62	1.14	4.18
2012	69.77	96.01	1.40	4.80
2013	73.59	101.76	1.47	5.09
2014*	77.27	105.77	1.55	5.29
2015*	72.10	105.37	1.44	5.27
2016*	64.83	100.42	1.30	5.02
2017*	76.17	112.00	1.52	5.60
2018*	67.84	95.47	1.36	4.77

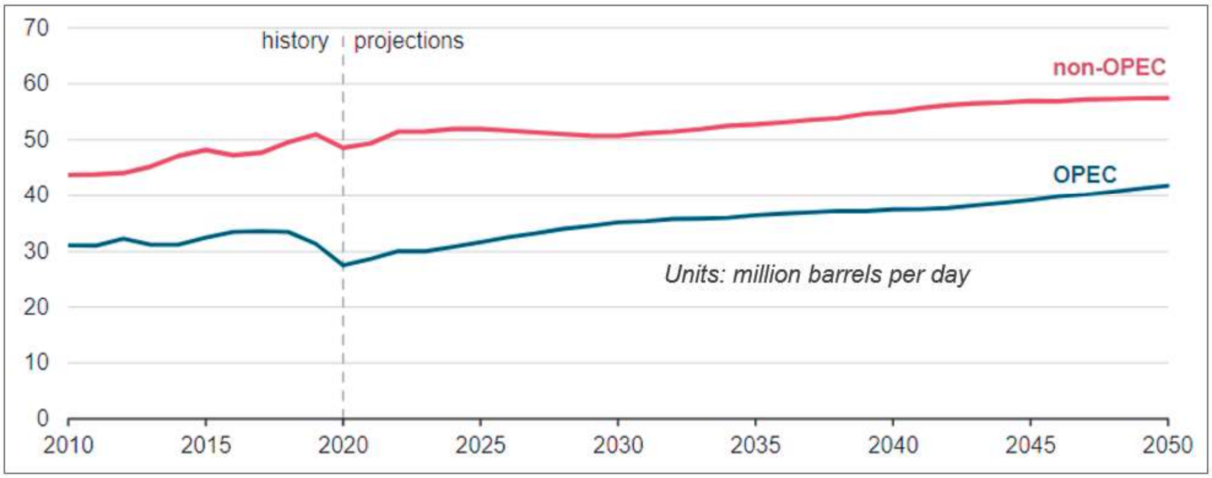
Description	*Diesel*	*Gasoline*
Assumption (blending mandate)	*2%*	*5%*

Table 17 Renewable Diesel and Ethanol Demand; Units: million liters / day

4.2 AN OVERVIEW OF US REFINING SECTOR

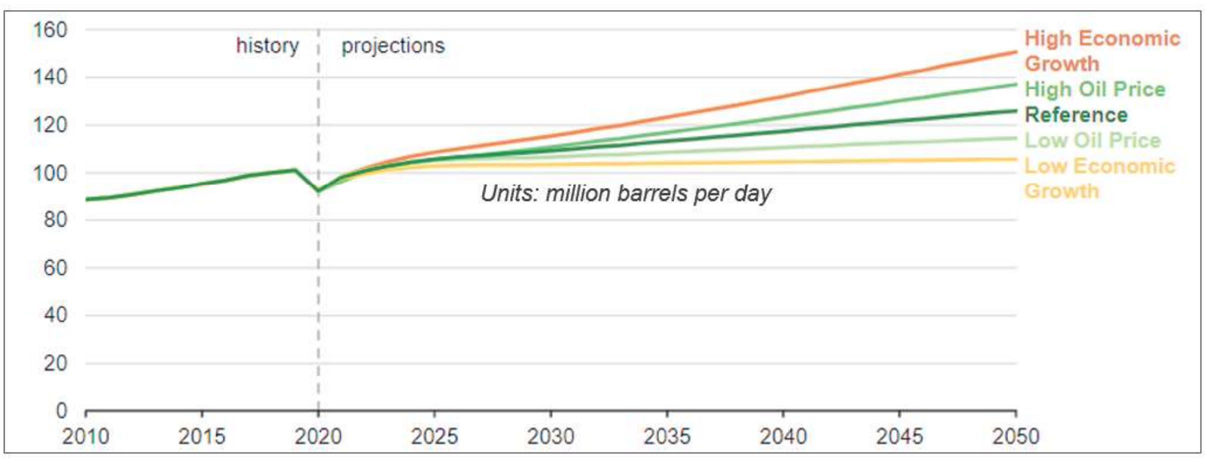
4.2.1 Introduction

The US Energy Information Administration (EIA)[26] forecasts that demand for crude oil, liquid fuels production and petroleum products will continue past 2050 (Figure 15 to Figure 17) alongside of and despite increased electric vehicle (EV) penetration, see Figure 18.



Reference: US Energy Information Administration. International Energy Outlook 2021. https://www.eia.gov/outlooks/ieo/production/sub-topic-01.php

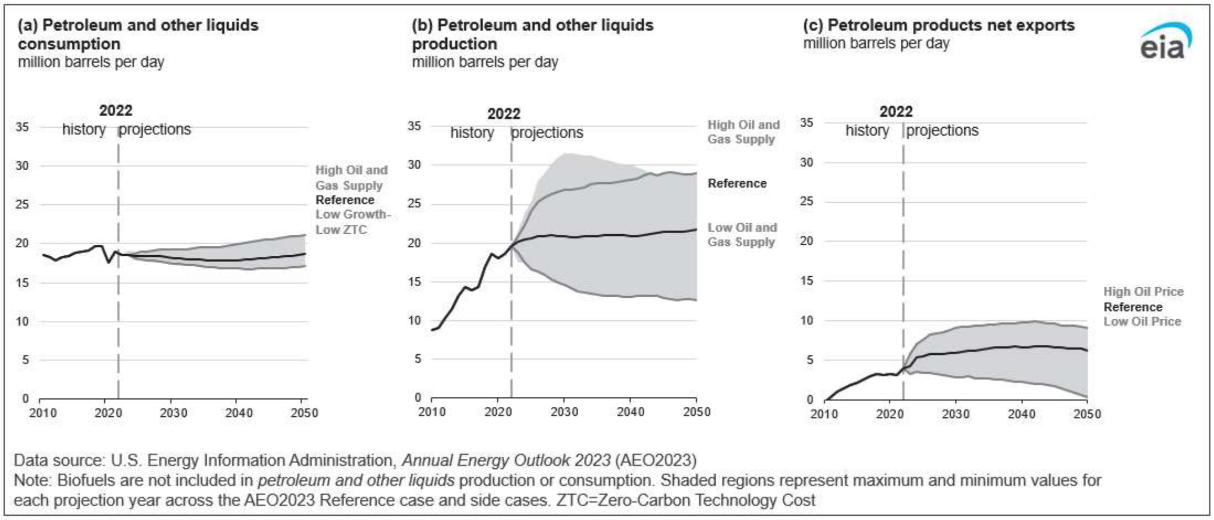
Figure 15 World Crude Oil and Lease Condensate Production (EIA)



Reference: US Energy Information Administration. International Energy Outlook 2021. https://www.eia.gov/outlooks/ieo/production/sub-topic-01.php

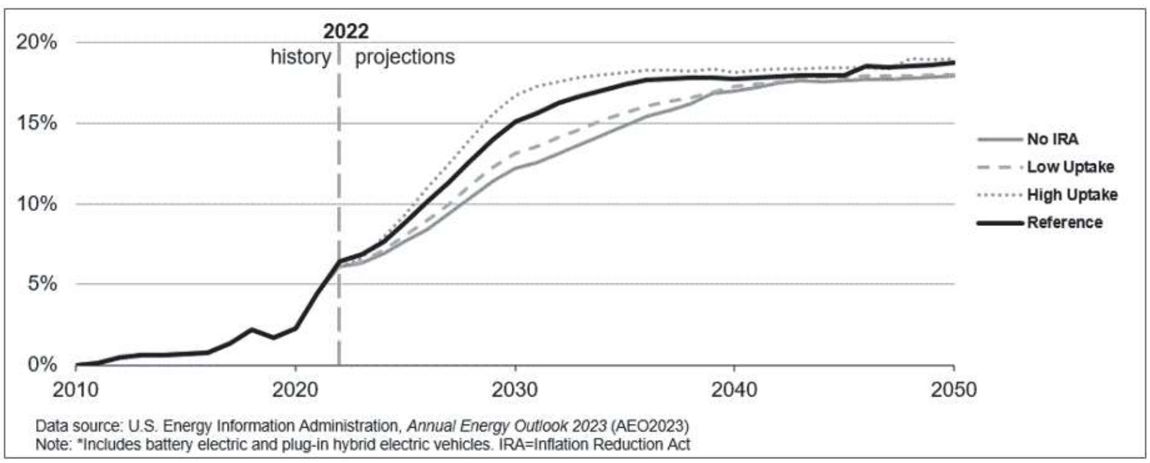
Figure 16 World Liquid Fuels Consumption (EIA)

[26] US Energy Information Administration; https://www.eia.gov/



Reference: US Energy Information Administration. Annual Energy Outlook 2023 with projections to 2050. March 16, 2023. www.eia.gov/aeo

Figure 17 US Production of Petroleum Products 2024 through 2050



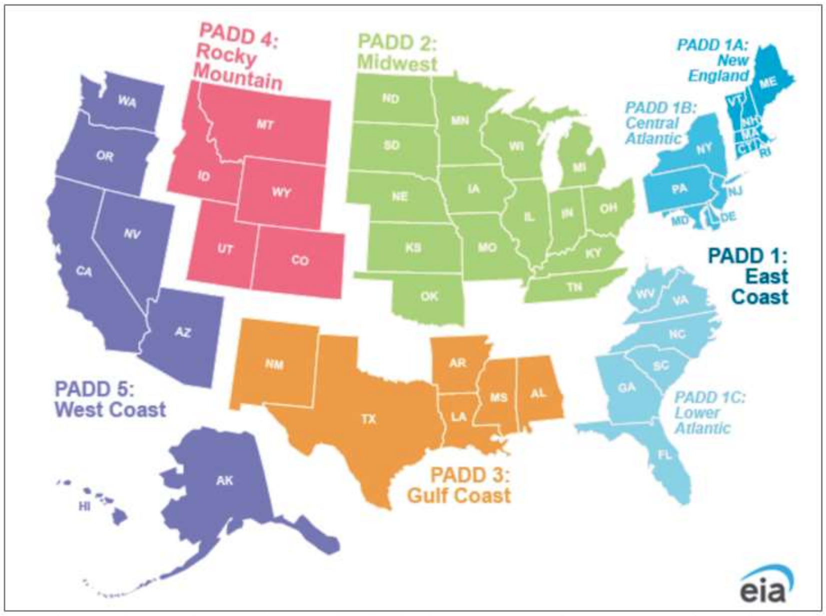
Reference: US Energy Information Administration. Annual Energy Outlook 2023 with projections to 2050. March 16, 2023. www.eia.gov/aeo

Figure 18 Market Share of Electric Light-Duty Vehicles, US (EIA)

4.2.2 US Refining

The US from a refinery perspective is divided into 'PADDS' - Petroleum Administration for Defense Districts[27]; Figure 19.

[27] "*The Petroleum Administration for Defense Districts (PADDs) are geographic aggregations of the 50 States and the District of Columbia into five districts: PADD 1 is the East Coast, PADD 2 the Midwest, PADD 3 the Gulf Coast, PADD 4 the Rocky Mountain Region, and PADD 5 the West Coast. Due to its large population, PADD 1 is further divided into sub-PADDs, with PADD 1A as New England, PADD 1B the Central Atlantic States, and PADD 1C*



Reference: US Energy Information Administration. https://www.eia.gov/petroleum/weekly/includes/padds.php

Figure 19 US EIA Petroleum Administration for Defense Districts

Under the banner of the EIA, refiners' report on their capacity and product slate amongst other parameters. As of January 2023, the EIA reported the US had 129 operating refineries with a capacity (atmospheric distillation) of approximately 18 million barrels / day; per Table 18.

---

comprising the Lower Atlantic States. There are two additional PADDs (PADDs VI and VII) that encompass U.S. Territories. The PADDs help users of EIA's petroleum data assess regional petroleum product supplies.

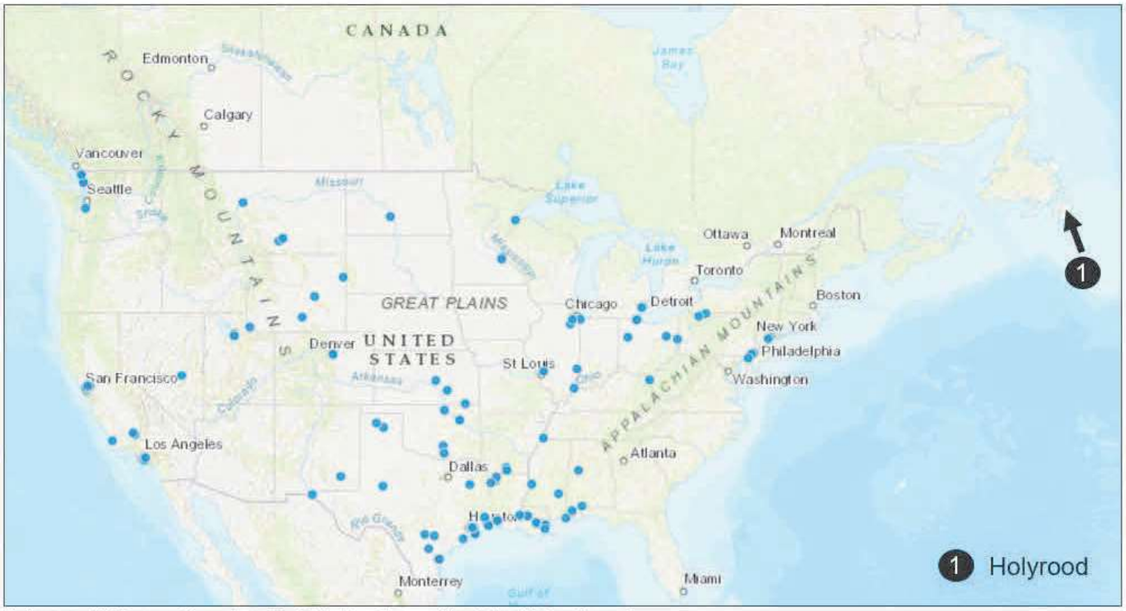
During World War II the Petroleum Administration for War, established by an Executive order in 1942, used these five districts to ration gasoline. Although the Administration was abolished after the war in 1946, Congress passed the Defense Production Act of 1950, which created the Petroleum Administration for Defense and used the same five districts, only now called the Petroleum Administration for Defense Districts." Reference: https://www.eia.gov/todayinenergy/detail.php?id=4890

No	PAD District / State	No. Operable Refineries			Atmospheric Crude Oil Distillation Capacity					
					Barrels per Calendar Day			Barrels per Stream Day		
		Total	Operating	Idle [a]	Total	Operating	Idle [b]	Total	Operating	Idle [b]
1	PADD I	7	7	-	877,800	877,800	-	930,900	930,900	-
2	Delaware	1	1	-	171,000	171,000	-	180,000	180,000	-
3	New Jersey	2	2	-	418,500	418,500	-	438,100	438,100	-
4	Pennsylvania	3	3	-	266,000	266,000	-	289,800	289,800	-
5	West Virginia	1	1	-	22,300	22,300	-	23,000	23,000	-
6	PADD II	25	22	3	4,206,105	3,948,885	257,220	4,464,787	4,179,287	285,500
7	Illinois	4	4	-	1,043,485	1,043,485	-	1,100,800	1,100,800	-
8	Indiana	2	2	-	469,500	469,500	-	475,700	475,700	-
9	Kansas	3	3	-	404,600	404,600	-	416,767	416,767	-
10	Kentucky	1	1	-	291,000	291,000	-	306,000	306,000	-
11	Michigan	1	1	-	140,000	140,000	-	152,000	152,000	-
12	Minnesota	2	2	-	440,000	440,000	-	485,000	485,000	-
13	Dakota	1	1	-	71,000	71,000	-	74,000	74,000	-
14	Ohio	4	3	1	604,720	455,800	148,920	630,000	470,000	160,000
15	Oklahoma	5	4	1	523,800	453,500	70,300	569,520	494,020	75,500
16	Tennessee	1	1	-	180,000	180,000	-	205,000	205,000	-
17	Wisconsin	1	-	1	38,000		38,000	50,000	-	50,000
18	PADD III	56	56	-	9,676,729	9,676,729	-	10,276,994	10,276,994	-
19	Alabama	3	3	-	142,100	142,100	-	148,700	148,700	-
20	Arkansas	2	2	-	90,500	90,500	-	92,700	92,700	-
21	Louisiana	15	15	-	2,964,220	2,964,220	-	3,116,355	3,116,355	-
22	Mississippi	3	3	-	393,940	393,940	-	415,000	415,000	-
23	New Mexico	1	1	-	110,000	110,000	-	124,000	124,000	-
24	Texas	32	32	-	5,975,969	5,975,969	-	6,380,239	6,380,239	-
25	PADD IV	15	13	2	650,164	537,564	112,600	696,200	574,500	121,700
26	Colorado	2	-	2	103,000		103,000	111,700	-	111,700
27	Montana	4	4	-	214,600	205,000	9,600	223,400	213,400	10,000
28	Utah	5	5	-	206,714	206,714	-	217,200	217,200	-
29	Wyoming	4	4	-	125,850	125,850	-	143,900	143,900	-
30	PADD V	26	26	-	2,649,571	2,643,571	6,000	2,787,900	2,779,900	8,000
31	Alaska	5	5	-	165,500	165,500	-	180,000	180,000	-
32	California	14	14	-	1,740,371	1,734,371	6,000	1,835,400	1,827,400	8,000
33	Hawaii	1	1	-	93,500	93,500	-	95,000	95,000	-
34	Nevada	1	1	-	2,000	2,000	-	5,000	5,000	-
35	Washington	5	5	-	648,200	648,200	-	672,500	672,500	-
36	Total	129	124	5	18,060,369	17,684,549	375,820	19,156,781	18,741,581	415,200

Reference(s)	Energy Information Administration, Refinery Capacity 2023. https://www.eia.gov/petroleum/refinerycapacity/
Note(s)	*(a) Refineries where distillation units were completely idle but not permanently shutdown on January 1, 2023.* *(b) Includes capacity from refineries that are either completely or partially idle.*

Table 18 US Operable Refineries by PADD (January 2023)

Mostly for historical reasons and molded by economic and technology factors, US refineries are located across the US; see Figure 20. A partial exception to this is the concentration of refineries in the US Gulf Coast where refiners have over time diversified into the production of chemicals and their derivatives, and located at the coast to have ready access to port facilities for export.

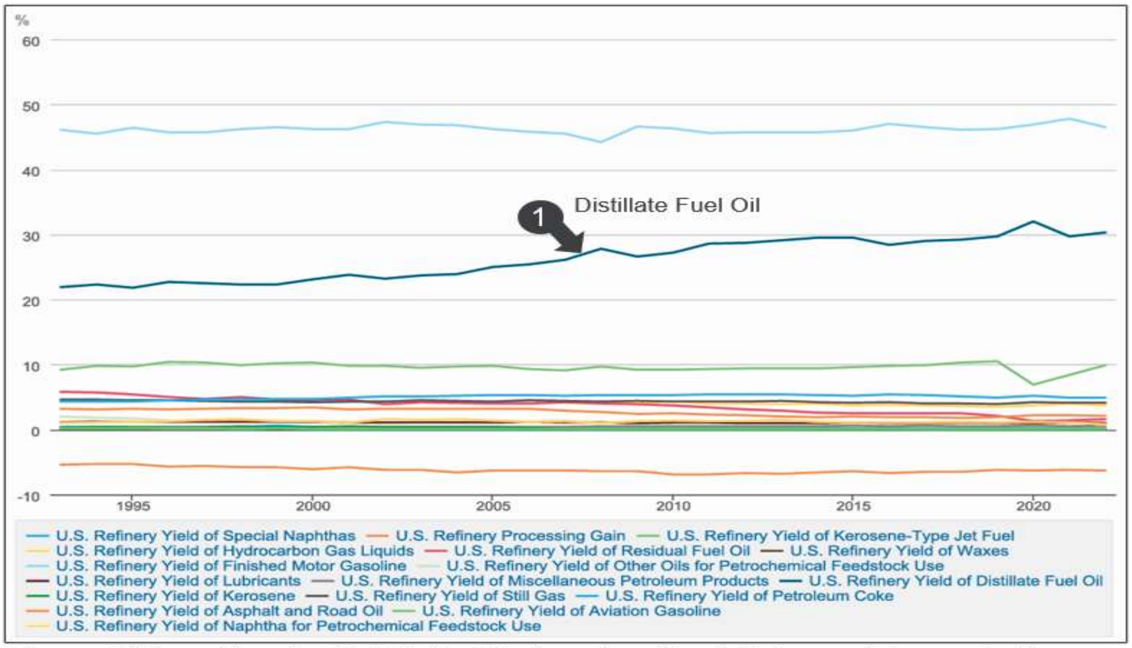


Reference: US Energy Information Administration; Energy Atlas. https://atlas.eia.gov/

Figure 20 Location of US Refineries

In addition to transportation fuels (aviation fuel, diesel, gasoline) refineries produce a range of products inherently necessary to modern society such asphalt (road building, roofing, sealants), heating oils, lubricants, precursors for modern plastics and solvents to name a few.

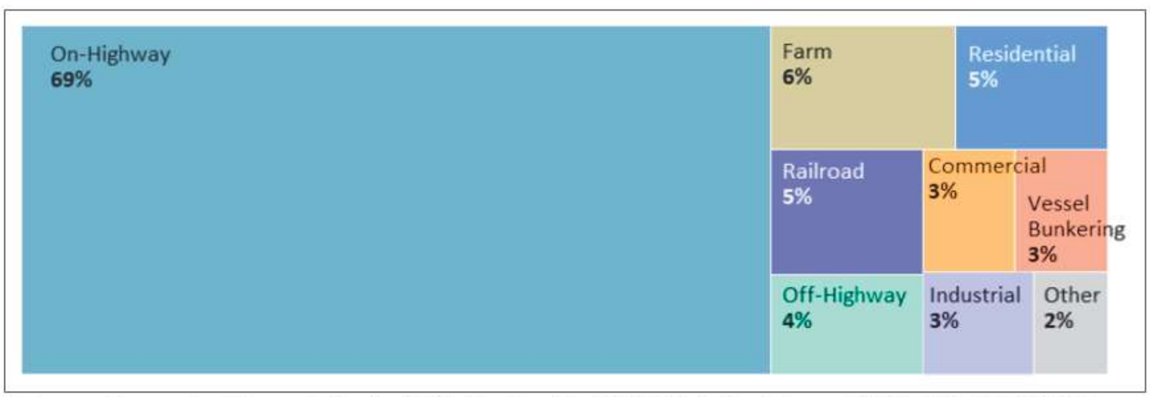
Diesel is part of a category referred to as ‘distillate fuel’, the percentage of US refining capacity directed to the production of said product is shown in Figure 21 for 1995 to 2020.



Reference: US Energy Information Administration. https://www.eia.gov/dnav/pet/pet_pnp_pct_dc_nus_pct_a.htm

Figure 21 US Refinery Utilization (1995 – 2020)

The volume of distillate directed to diesel for on-highway use is reported as 69%; Figure 22.



Reference: Congressional Research Service (CRS); Diesel and Fuel Oil: Distillate Supply Issues, R4746, 9 March 2023; PDF page no. 6. https://crsreports.congress.gov/

Figure 22 Distillate Fuel by End Use, US

Extrapolating from Figure 21 and Figure 22, the US produces roughly 3.7 million barrels of diesel per day; Table 19. In comparative terms this is overwhelmingly more than the volume of renewable diesel currently and forecast to be available, ~150,000 bpd and ~380,000 bpd in 2022 and 2025 respectfully; see Figure 23.

No	Description	Barrels / day (million)
1	US refining Capacity	18.1
2	Distillate Fuel Oils	5.4
3	Diesel	3.7
	Distillate Fuel Oils - % of Refining Capacity	*30%*
	Diesel as % of Distillate Fuel Oils	*69%*

Table 19 Diesel Production in the US (rough order of magnitude)

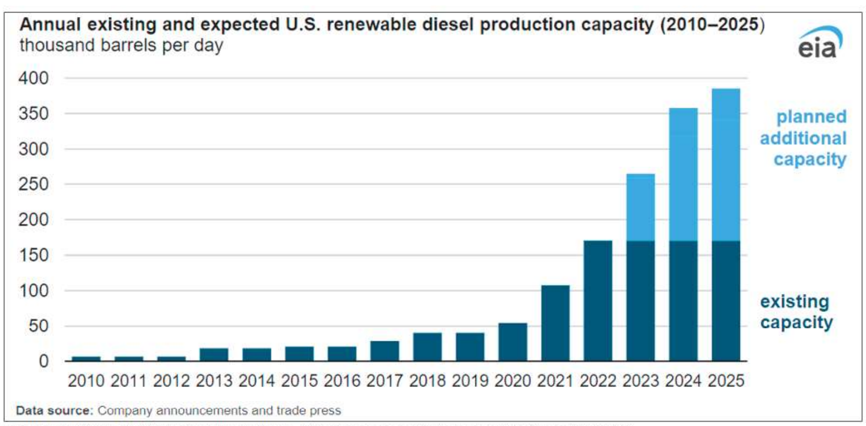
4.2.3 US Biodiesel and Renewable Diesel

As of January 2024, US companies producing renewable diesel are listed in Table 20. Total capacity is approximately 238,000 barrels/ day, slightly more than the volume reported by the EIA in Figure 23. A significant expansion would be required to achieve the EIA forecast of approximately 380,000 barrels per day by 2025.

No	Company	Location	State	PADD	Gallons / year (million)	Liters / annum (million)	Barrels / annum (million)	Bpd
1	Altair Paramount	Paramount	California	5	42	159	1.000	2,941
2	BP Products North America[1]	Blaine	Washington	5	111	420	2.643	7,772
3	Chevron USA Inc[1]	El Segundo	California	5	31	116	0.731	2,150
4	Cheyenne Renewable Diesel Co LLC	Cheyenne	Wyoming	4	92	348	2.190	6,442
5	CVR Renewables Wynnewood LLC	Wynnewood	Oklahoma	2	212	803	5.047	14,845
6	Dakota Prairie Refining LLC	Dickinson	North Dakota	2	192	725	4.559	13,409
7	Diamond Green LLC	Port Arthur	Texas	3	537	2,031	12.775	37,574
8	Diamond Green LLC	Norco	Louisiana	3	982	3,717	23.374	68,748
9	HF Sinclair Renewables Holding Co LLC	Artesia	New Mexico	3	141	535	3.366	9,901
12	Jaxon Energy, LLC	Jackson	Mississippi	3	25	95	0.595	1,751
13	Kern Oil & Refining[1]	Bakersfield	California	5	6	23	0.143	420
13	Martinez Renewable Fuels	Pacheco	California	5	260	984	6.190	18,206
14	Montana Renewables LLC	Great Falls	Montana	4	184	697	4.381	12,884
15	New Rise Renewables	Reno	Nevada	5	46	173	1.088	3,200
16	Phillips 66 Co	Rodeo	California	5	180	681	4.285	12,604
17	Renewable Energy Group	Geismar	Louisiana	3	101	380	2.393	7,037
18	Seaboard Energy	Hugoton	Kansas	2	85	322	2.024	5,952
19	Shell	Norco	Louisiana	3	54	203	1.278	3,760
20	Wyoming Renewable Diesel	Sinclair	Wyoming	4	117	443	2.785	8,193
21	**Total**				**3,396**	**12,855**	**81**	**237,789**

Reference / Notes
US Energy Information Administration; https://www.eia.gov/biofuels/renewable/capacity/
(1) Refineries co-processing renewable feedstock and petroleum.
Note: Totals may not equal sum of components due to independent rounding.

Table 20 U.S. Renewable Diesel Fuel and Other Biofuels Production Capacity (January 2024)



Reference: US Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=55399

Figure 23 US Existing and Forecast Renewable Diesel Production Capacity (2010 - 2025)

4.3 MARKET CHANGES

Fundamental structural changes in the market are discussed in the following sub-sections.

4.3.1 Industry Structure

With the first refining of crude oil, came the need for transportation and distribution of a few and then an increasing number of products to an increasing number of locations. As the refining sector evolved, so has the supply chain servicing it adapted. Figure 24 illustrates how this has changed in the past 100 years or so and how it will come under pressure in the future with increasing electrification.

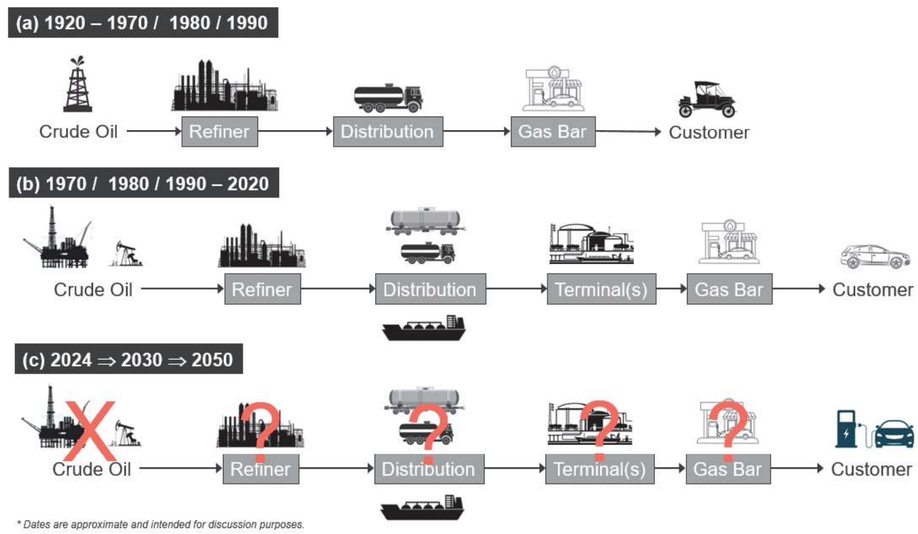


Figure 24 Crude Oil, Refining and Fuels – An Evolving Sector

- Graphic (a): illustrative of a refinery with distribution of product conducted on a more local basis, where the refiner is forward integrated into distribution and sale of product at company owned gas bars.

- Graphic (b): illustrates a period of history following consolidation in the refining sector, where the scale of refineries has grown and refiners have extended their operations beyond their original home market to neighboring province(s) or state(s) or even exported out of country and as they do so, they become more reliant on new infrastructure such as rail cars and terminals and in turn companies specializing in transport, supply and distribution (TS&D) and retail sale of product. With possible exception of flag-ship locations, some refiners adopt a franchise model for gas bars. The impact of longer supply chains and possible changes of product ownership along the way on fuel quality and stability is discussed in section 7.3 Fuel Composition and Fuel Stability page 97.

- Graphic (c): illustrates a future scenario in which the energy transition questions the continued operations of the liquid TS&D and retail sale of diesel and gasoline as it is replaced in part or completely by electrical power distributed by a new form of supply chain.

4.3.2 Residential Heating

The following to be read in conjunction with Section 7 page 95.

Numerous cities across Canada have announced their intentions in the past few years to limit or ban heating oil and or natural gas in new construction. Should good intentions become policy and/or regulations, this will likely over time erode demand for fossil-based gas or liquid fuel for the purpose of cooking and or heating.

What these intentions have yet to comprehensively address is: how do communities - some more remote than others and logistically constrained - practically live when they have no power generation capability of their own or have no access to power [distribution network down] for a period of time[28].

Solar and wind power suffer from a similar challenge. Both offer the opportunity for a community to be self-sustaining, but on practical terms they need to maintain connection to a larger power grid network for "firm capacity" for instances when they are independently unable to meet their required power demand.

Hence, whilst communities can be expected to reduce their daily reliance of fossil-based fuels, until such time as renewable electric power has proven itself reliable to the extent consumers are accustomed to, the need for liquid-based fuels to supply emergency back-up gas turbines or similar is unlikely to disappear any time soon. Given the latter scenario is not unique to the Island of Newfoundland, diesel fuel or suitable alternatives should be expected to be available in the market for some time to come.

4.3.3 Vehicle Electrification

Newfoundland has a population of approximately 507,000[29] with a reported 40% living on the Avalon Peninsula thus indicating the area of greatest power demand regarding home heating and future EV growth.

The number of registered vehicles in the province of Newfoundland and Labrador[30] are reported in Table 21; numbers specific to the island of Newfoundland itself were not located. For comparative purposes, the same data has been provided for Canada; see Table 22. Averages for 2017 to 2022 to note are:

- Number of Vehicle registered in:
  - Newfoundland and Labrador: 383,000
  - Canada: 25.6 million
- Fleet (% Light Duty Vehicle (LDV) / Total Fleet)
  - Newfoundland and Labrador: 93%
  - Canada: 92%
- Diesel: Gasoline vehicle split (%)
  - Newfoundland and Labrador: 4.1%
  - Canada: 6.6%
- Percentage Total Alternative / Total Fleet
  - Newfoundland and Labrador: 0.4% or 1,488 vehicles
  - Canada: 1.6% or 421,000 vehicles

---

[28] Based on the reliability of utility providers most Canadian enjoy across the country, from a consumer perspective the definition of 'time' here – the maximum period of time a consumer will reasonably expect / tolerate an energy outage for - can be expected to fall somewhere between 5 and 60 minutes and less in adverse winter conditions.
[29] https://en.wikipedia.org/wiki/Demographics_of_Newfoundland_and_Labrador
[30] https://www.stats.gov.nl.ca/statistics/Statistics.aspx?Topic=transportation

It is pertinent to note that the high number of gasoline vehicles does not imply Canada produces and uses less diesel fuel; this is not the case. Whilst the fleet is dominated by gasoline engines, these fall dominantly in the LDV segment and on average will drive less kilometers annually than would the diesel fleet.

No	Description	2017	2018	2019	2020	2021	2022	Average
1	**Total, road motor vehicle registrations**	391,969	381,268	377,224	374,057	383,706	388,449	382,779
2	Gasoline (total)	374,687	364,572	360,722	357,742	366,128	369,554	365,568
3	Diesel (total)	16,507	15,834	15,260	14,999	15,710	15,969	15,713
4	Battery (total)	28	31	47	83	154	366	118
5	Hybrid (total)	655	736	1,085	1,097	1,516	2,228	1,220
6	Hybrid - plug in (total)	83	81	95	119	179	314	145
7	Other fuel types 4 (total)	9	14	15	17	19	18	15
8	Total (alternative)	775	862	1,242	1,316	1,868	2,926	1,498
9	% (Gasoline / Total Fleet)	95.6%	95.6%	95.6%	95.6%	95.4%	95.1%	95.5%
10	% (Diesel / Total Fleet)	4.2%	4.2%	4.0%	4.0%	4.1%	4.1%	4.1%
11	**Total, vehicles weighing less than 4,535 kilograms** [(a)]	362,778	353,662	350,573	347,356	355,289	359,301	354,827
12	Gasoline (total)	355,686	346,743	343,463	340,288	347,445	350,142	347,295
13	Diesel (total)	6,326	6,067	5,877	5,763	5,988	6,244	6,044
14	Battery (total)	25	29	46	81	151	364	116
15	Hybrid (total)	655	736	1,085	1,097	1,516	2,228	1,220
16	Hybrid - plug in (total)	83	81	95	119	179	314	145
17	Other fuel types 4 (total)	3	6	7	8	10	9	7
18	Total (alternative)	766	852	1,233	1,305	1,856	2,915	1,488
19	% (LDV - Gasoline / Total Fleet)	90.7%	90.9%	91.1%	91.0%	90.5%	90.1%	90.7%
20	% (LDV - Diesel / Total Fleet)	1.6%	1.6%	1.6%	1.5%	1.6%	1.6%	1.6%
21	% (LDV - Alternative / Total Fleet)	0.2%	0.2%	0.4%	0.4%	0.5%	0.8%	0.4%
22	% (LDV / Total Fleet)	92.6%	92.8%	92.9%	92.9%	92.6%	92.5%	92.7%
23	% (LDV - Gasoline / LDV)	98.0%	98.0%	98.0%	98.0%	97.8%	97.5%	97.9%
24	% (LDV - Diesel / LDV)	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
25	% Share (alternative)	0.2%	0.2%	0.3%	0.3%	0.5%	0.8%	0.4%
Reference(s)		*Statistics Canada. Table 23-10-0308-01 Vehicle registrations, by type of vehicle and fuel type. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310030801*						

Color has no other meaning that to highlight the differential between cells highlighted.

(a) Light-duty vehicles refer to vehicles with a GVWR less than 4,535 kilograms and includes GVWR classes 1 and 2.

GVWR - Gross Vehicle Weight Rating
LDV - Light Duty Vehicle

Table 21 Newfoundland and Labrador: Road Vehicle Registrations, 2017 to 2022

No	Description	2017	2018	2019	2020	2021	2022	Average
1	**Total, road motor vehicle registrations**	24,618,831	25,043,044	25,426,285	25,744,196	26,223,871	26,302,526	25,559,792
2	Gasoline (total)	22,742,978	23,113,771	23,400,663	23,622,568	23,924,617	23,813,725	23,436,387
3	Diesel (total)	1,656,925	1,657,715	1,676,823	1,688,814	1,741,642	1,764,014	1,697,656
4	Battery (total)	19,926	36,185	66,847	103,628	153,349	225,269	100,867
5	Hybrid (total)	172,069	191,675	218,162	247,356	303,079	372,704	250,841
6	Hybrid - plug in (total)	23,881	40,246	59,716	77,101	95,896	121,265	69,684
7	Other fuel types 4 (total)	3,052	3,452	4,074	4,729	5,288	5,549	4,357
8	Total (alternative)	218,928	271,558	348,799	432,814	557,612	724,787	425,750
9	% (Gasoline / Total Fleet)	92.4%	92.3%	92.0%	91.8%	91.2%	90.5%	91.7%
10	% (Diesel / Total Fleet)	6.7%	6.6%	6.6%	6.6%	6.6%	6.7%	6.6%
11	**Total, vehicles weighing less than 4,535 kilograms** [(a)]	22,724,146	23,099,029	23,446,888	23,747,627	24,097,365	24,121,572	23,539,438
12	Gasoline (total)	21,806,878	22,157,786	22,425,829	22,640,309	22,859,005	22,722,803	22,435,435
13	Diesel (total)	701,254	672,994	676,098	679,032	685,920	679,794	682,515
14	Battery (total)	19,633	35,811	66,418	103,100	152,685	224,175	100,304
15	Hybrid (total)	172,064	191,670	218,156	247,350	303,073	372,696	250,835
16	Hybrid - plug in (total)	23,881	40,246	59,716	77,101	95,896	121,261	69,684
17	Other fuel types 4 (total)	436	522	671	735	786	843	666
18	Total (alternative)	216,014	268,249	344,961	428,286	552,440	718,975	421,488
19	% (LDV - Gasoline / Total Fleet)	88.6%	88.5%	88.2%	87.9%	87.2%	86.4%	87.8%
20	% (LDV - Diesel / Total Fleet)	2.8%	2.7%	2.7%	2.6%	2.6%	2.6%	2.7%
21	% (LDV - Alternative / Total Fleet)	0.9%	1.2%	1.5%	1.8%	2.3%	3.0%	1.8%
22	% (LDV / Total Fleet)	92.3%	92.2%	92.2%	92.2%	91.9%	91.7%	92.1%
23	% (LDV - Gasoline / LDV)	96.0%	95.9%	95.6%	95.3%	94.9%	94.2%	95.3%
24	% (LDV - Diesel / LDV)	3.1%	2.9%	2.9%	2.9%	2.8%	2.8%	2.9%
25	% Share (alternative)	0.9%	1.1%	1.4%	1.7%	2.1%	2.7%	1.6%
Reference(s)		*Statistics Canada. Table 23-10-0308-01 Vehicle registrations, by type of vehicle and fuel type. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310030801*						

Color has no other meaning that to highlight the differential between cells highlighted.
(a) Light-duty vehicles refer to vehicles with a GVWR less than 4,535 kilograms and includes GVWR classes 1 and 2.

GVWR - Gross Vehicle Weight Rating
LDV - Light Duty Vehicle

Table 22 Canadian Vehicle Fleet: Diesel versus Gasoline, 2017 - 2022

4.4 REGULATION IN CANADA

The legislation discussed in this report includes that which may directly impact Hydro's operations as well as that may have indirect impacts to the diesel supply chain.

In support of Canada's greenhouse gas emission (GHG) targets for 2030 and net-zero goal by 2050, the Clean Fuels Branch of Natural Resources Canada (NRCAN) has a mandate to stimulate growth of clean fuel industries across Canada. Examples of Government action taken in this regard are:

- December 2020: publication of the draft Clean Fuels Regulations and launch of Canada's Hydrogen Strategy,
- $8B for the Strategic Innovation Fund Net-Zero Accelerator,
- $1.5B to establish a Clean Fuels Fund,
- $1.38B to support for build out new or expansion of existing clean fuel production capacity, and
- $19.4M to support the development of critical codes, standards, and regulations.

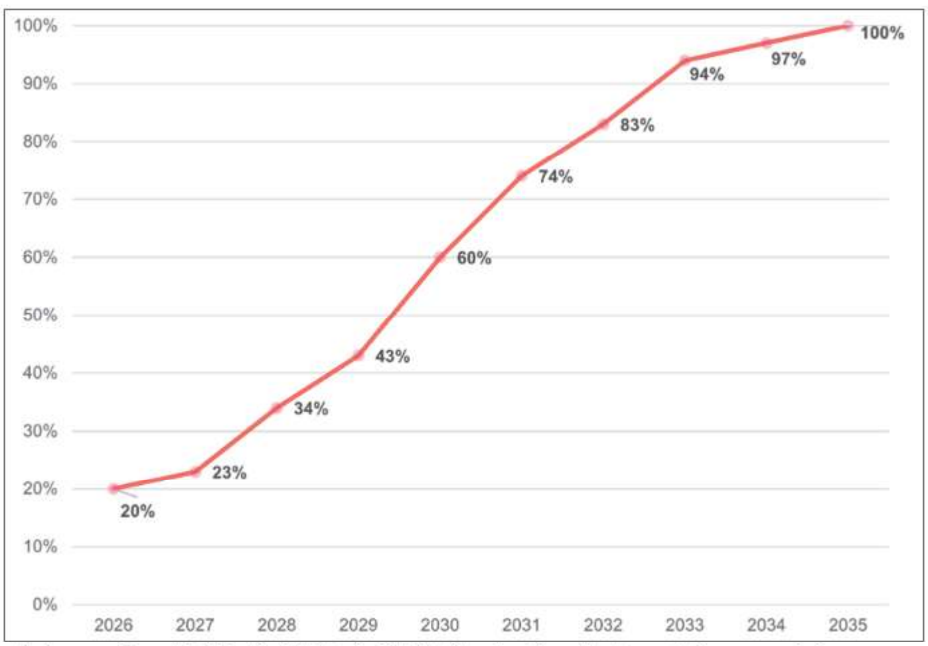
Regulation relevant to EVs, fuel demand / pricing and fuel supply whether in force or proposed are discussed in the following.

4.4.1 Canada's Electric Vehicle Availability Standard

Announced in draft on December 21, 2022, the Electric Vehicle Availability Standard (EVAS) applies to LDVs[31]. LDV's account for about half of Canada's transportation sector's GHG emissions; the sector reportedly accounts for approximately 25% of Canada's total emissions.

Per requirements of EVAS, automotive producers and importers must meet annual zero-emission vehicle (ZEV) sales targets beginning model-year-2026 with at least 20% of new LDVs offered as ZEVs and increasing annually by 60% reaching 100% for 2035; Figure 25.

At an assumed average vehicle age of between 8 and 15 years, it can be expected that EVAS will begin to 'gently' impact the volume of gasoline entering the market and by implication the volume produced by Canadian refiners towards 2030 and possibly more aggressively so after 2035. A knock-on effect can be expected on diesel demand and refiners' willingness to produce and possibly remain operating when a sizable part of their market is stagnant or in decline.



Reference: Canada's Electric Vehicle Availability Standard (regulated targets for zero-emission vehicles. https://www.canada.ca/en/environment-climate-change/news/2023/12/canadas-electric-vehicle-availability-standard-regulated-targets-for-zero-emission-vehicles.html

Figure 25 Canada Electric Vehicle Availability Standard

[31] Passenger cars, SUVs, and light trucks.

4.4.2 Clean Electricity Regulations

While Canada was one of the first countries to commit to a net-zero grid, the country has since been joined by all G7 countries in committing to a net-zero electricity system by 2035. Canada's draft Clean Electricity Regulations (CER) were developed around three core principles - to maximize and maintain the following:

- GHG reductions to achieve net-zero emissions from the electricity grid by 2035,
- Electricity affordability for Canadians, and
- Grid reliability to support a strong economy and meet Canada's growing energy needs.

CER is an integral part of Canada's 2030 Emissions Reduction Plan to help the country reach its emissions reduction target of 40 to 45% below 2005 levels by 2030 and net-zero by 2050.

On August 10, 2023, Environment and Climate Change Canada (ECCC) made the draft regulations public, with a seventy-five-day formal consultation period, which began August 19, 2023. An update based on public feedback was published February 16, 2024[32]. The Government of Canada designed CER to maximize GHG reduction in the electricity sector whilst enabling Canadians to continue to have access to reliable and affordable power. CER aims to set a technology-neutral emissions standard for the generation of electricity that is provided to the grid as of 2035.

To support reliability and affordability, draft regulations include flexibilities that allow a limited and declining ongoing role for fossil fuel production (including diesel). This flexible approach will enable provincial utilities and system operators to plan and manage their systems in accordance with relevant provincial circumstances, while creating a clear signal for reducing emissions over time.

CER is a critical part of an overall approach to the clean electrification of the Canadian economy - the approach is supported by federal investments in clean electricity of over C$40 billion, including historic announcements in Budget 2023, as well as by the recently launched Canada Electricity Advisory Council. The information below includes discussion of the initial draft CER as well as a more recent update published by ECCC based on feedback provided on the draft.

4.4.2.1 Details of Draft CER Relevant to Holyrood Gas Turbines

The draft CER sets a GHG emissions standard / threshold on electricity generators and follows a technology-neutral approach to give utility operators the discretion to determine the most practical and least costly pathway to comply. Based on feedback and updated information of February 2024, the emissions threshold is expected to be set on a facility specific basis.

CER would apply to any generating unit[33] that meets the following three criteria on or after January 1, 2025:

---

[32] Clean Electricity Regulations, Public Update, Public Update: 'What We Heard' during consultations and directions being considered for the final regulations, Feb. 16, 2024. https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity-regulation.html#toc1

[33] An electricity generation unit ('unit') means an assembly of equipment that generates electricity. It must include at least a boiler or combustion engine and may include carbon capture and storage (CCS).

- Uses any amount of fossil fuels to generate electricity,
- Has a capacity of 25 MW or greater, and
- Is connected to an electricity system that is subject to North American Electric Reliability Corporation (NERC) standards ('NERC-regulated electricity system').

Only those units that are net exporters to a NERC regulated electricity system in a given calendar year would be subject to the CER's performance standard for that year.

The initial performance standard proposed was 30 tonnes CO_2 / GWh of electricity generated as measured on an annual average basis. For reference, best performing natural gas plants in Canada emit in the range of 350 to 420 tCO_2/GWh and conventional coal units about 1,000 tCO_2/GWh.

Based on Holyrood's 2022 GHG report, the GHG intensity (or carbon intensity, CI) of the 123.5MW gas turbine was over 1,000 tCO_2/GWh (total emissions reported 1,992 t CO_2e, total electricity production - 1.718 GWh as per Stantec 2023)[34]. It is assumed the CI of the gas turbine is higher than typically seen with diesel due to the low(er) load of typical operation. Typical diesel-based electricity is reported as 736 tCO_2e/GWh per the federal government's discussion paper on the draft CER[35].

The CER would take effect for an individual generation unit on January 1, 2035 or 20 years after a unit is commissioned (with some exceptions) for units in place prior to January 1, 2025. Where possible - in regions with suitable use and/or storage reservoirs - carbon capture utilization and storage (CCS/CCUS) could be used as a means of reducing carbon emissions from fossil-fuel generated electricity. Alternatively, biofuels may be used to lower GHG intensity. There is also discussion on the use of GHG offsets and the pooling of allowable annual emissions across all units owned by the same operator. It is unclear whether allowable emissions could be assigned to renewable energy such as Hydro's renewable generation units however as the draft CER currently only indicates it is applicable to fossil fuel burning combustion units; the former does not currently appear to be permissible.

As currently drafted, CER provides up to a 20-year grace period before the regulations take effect on natural gas facilities that are commissioned before January 1, 2025. In the February 2024 update from ECCC, they indicated that consideration is being given to allowing natural gas units that have substantial investment and work underway but are unable to commission by January 1, 2025, to make use of the 20-year grace period provisions provided they start selling electricity to the grid by a future date to be determined. The duration of these units' prescribed lives would be shortened commensurate with their delay in commissioning past 2025 so that such units would become subject to a regulated annual emissions limit no later than a unit commissioned by January 1, 2025. This would avoid adverse impacts on investment decisions in relation to natural gas units that have already been made. **Note, there is no grace period for units commissioned after January 1, 2025, nor liquid fueled units (including diesel) as is expected to be the case for Holyrood**.

---

[34] Verification Report: Newfoundland and Labrador Hydro 2022 GHG Reporting Forms Holyrood Thermal Generating Station, Holyrood Gas Turbine, 1st September 2023.
[35] A clean electricity standard in support of a net-zero electricity sector: discussion paper. PDF page 19. March 8, 2022, https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/achieving-net-zero-emissions-electricity-generation-discussion-paper.html

4.4.2.2 Flexibility Mechanisms

The flexibility mechanisms are discussed in brief below.

Draft CER regulations provide an exemption for the use of fossil fuel-fired units in emergency circumstances - Holyrood GT could be operated without having to comply with the CER in emergency periods if the system operator declared an emergency [36]. Emissions would not be counted against the unit's annual emissions limit for a reasonable period of time (duration to be determined) to allow operators to respond to emergencies.

The regulations will also likely allow for the use of unabated fossil fuels[37] (except coal) on a limited basis only - as would be the case for Holyrood fueled by diesel - such as for meeting additional power requirements during peak power demand. Draft CER further directs that 'peaker provisions' will be limited to 450 hours per year and a total of 150,000 t CO_2 emitted in a given year per unit. This would likely apply to the 123.5MW turbine in some years as it has historically been operated less than 450 hours per year in a number of years based on Hydro data; Table 2 page 7. Note however, that based on the updated document published February 2024[34], government is considering removing the peaker provisions and replacing that with an absolute emissions limit for each unit. An estimate of this limit for the 123.5 MW turbine is provided in the next section.

4.4.2.3 Summary of Implications for Holyrood

Based on initial draft regulations and with exception of emergency circumstances, the existing 123.5 MW and future 150 MW turbines would be required to comply with the CER. Based on the updated document released in February 2024[32], ECCC indicated that each unit's capacity factor would depend on its efficiency and annual emissions limit. The update indicates ECCC is considering setting an absolute emissions maximum based on a unit of the same size operating for 100% of the year at a defined performance standard, (ECCC 2024). For example, based on the equation provided by ECCC[32] and the initially defined allowable intensity of 30 tCO_2e/GWh, allowable annual emissions for the 123MW turbine are estimated as follows:

- 123MW x 30 tCO_2e/GWh x 1GW/1,000MW x 8,760 hrs/year = 32,324 tCO_2e/year

This would result in the 123MW turbine being able to operate at maximum capacity approximately 10 full days per year on diesel prior to requiring credits or offsets for additional operation (based on the 2022 GHG intensity of 1,159 tCO_2e/GWh). Based on current information, were the 123MW GT operated at maximum capacity for 10, 20 or 42 days, it would emit approximately 34,000; 68,000 or 144,000 tonnes CO_{2eq} respectively. At a carbon price of C$170 / tonne (2030 federal price) and after accounting for an annual allowable limit, the unit could expect to incur a cost of somewhere between C$320,000 and C$19 million; Table 23. Operation of a 150MW turbine as envisaged on diesel at similar parameters would be expected to cost approximately C$392,000 to C$23 million; per Table 23. As it is unlikely the turbines

[36] Exemptions do not apply to small fossil fuel-fired units under 25MW or units not connected to the broader grid.
[37] The combustion of a fossil fuel in absence of carbon capture and storage.

would be operated continuously and at full load, the increasing costs for extended operations reflect a worst case scenario only.

(a) 123 MW Unit

No	Description	Units	Days 365	10	20	42
1	Hours (total)	as stated	8,760	240	480	1,008
2	GWh		1,077,480	29,520	59,040	123,984
3	tCO_2e / period		32,324	34,214	68,427	143,697
4	Annual Allowable limit	tCO_2e	32,324			
5	Emissions (under) / over (Credits required)	tCO_2e	-	1,889	36,103	111,373
6	Cost of emission credits	$C	-	321,178	6,137,503	18,933,420

Turbine rating	*MW*	*123*
Per CER regulation	*tCO2e/GWh*	*30*
Holyrood 2022 report	*tCO2e/GWh*	*1,159*
Carbon pollution price (2030 Federal)	*C$ / tonne*	*170*

(b) 150 MW Unit

No	Description	Units	Days 365	10	20	42
1	Hours (total)	as stated	8,760	240	480	1,008
2	GWh		1,314,000	36,000	72,000	151,200
3	tCO_2e / period		39,420	41,724	83,448	175,241
4	Annual Allowable limit	tCO_2e	39,420			
5	Emissions (under) / over (Credits required)	tCO_2e	-	2,304	44,028	135,821
6	Cost of emission credits	$C	-	391,680	7,484,760	23,089,536

Table 23 Cost of Emission Credits under Clean Electricity Regulations

There is mention / reference by the federal government to the use of offsets to achieve compliance, details however are not currently defined. There is also mention of allowing regulated parties that own or operate multiple units, to pool the emission limits of their individual existing units operating in the same jurisdiction. It is unclear whether Hydro could potentially gain credits from their hydroelectric operations to apply towards use of diesel in the Holyrood turbines, however it does not appear to be a mechanism based on the draft CER, only applying to fossil fuel units.

The final version of the CER is expected to be published in 2024. Eligible generating units must register with the Ministry by the end of 2025; emission intensity restrictions will take effect starting January 1, 2035.

4.4.3 Clean Fuel Regulations

The federal Clean Fuel Regulations (CFR) are intended to incentivize innovation and adoption of clean technologies and expand the use of low carbon intensity (CI) fuels in the economy; the regulations are focused on transportation fuels.

The CFR requires liquid fuel (gasoline, diesel, heating oil) primary suppliers - [defined as a person who: (a) owns, leases, operates, controls, or manages a fuel production facility in Canada at which gasoline or diesel is produced; or (b) imports gasoline or diesel into Canada] - to gradually reduce the CI of the fuels they sell in Canada.

The Regulations establish a credit market, where each credit represents a lifecycle emission reduction of one tonne of CO_2e. For each compliance period (typically a calendar year), a primary supplier (producers and importers) will need to demonstrate compliance with their reduction requirement by creating credits or acquiring credits from other suppliers, and then using the required number of credits to comply. Unlike the federal fuel charge on carbon pollution, the CFRs do not prescribe a price at the pumps. Rather, actual price impacts will depend on how producers and importers of diesel (and gasoline) choose to comply. Where there are not enough credits in the program, there is an option to create credits by contributing to a registered emission-reduction funding program.

The first compliance period was July 2023 to December 2023. In the early years, the Government of Canada expects there will be about three times as many credits in the market as will be required, meaning that the cost to acquire credits by any company needing them should be relatively low. This would imply that the impact on diesel pricing in the early years of the regulation will be low, gradually growing toward 2030. Impacts beyond 2030 are not stated.

4.4.3.1 Implications for Holyrood Gas Turbine(s)

As indicated by the Government of Canada in its regulatory analysis, the CFR will affect the economy via two main channels, by increasing production costs:

- Through incremental compliance and administrative costs: this **will increase** gasoline and **diesel prices** for households and industrial users. Credit creation opportunities for producers of low carbon fuels such as renewable diesel and hydrogen will make those low-carbon fuels and energy sources relatively less expensive.
- Sectors using diesel and gasoline will see their costs and productivity impacted. The change in relative prices of fuel are expected to lead to decreased demand for fossil derived fuels and increased demand for lower-carbon fuels (such as biofuels) and other energy options (solar, wind) as applicable.

According to ECCC's estimates in the regulatory impact assessment of CFRs, when fully implemented in 2030, the regulations **will increase the cost of diesel by 7 to 16 Canadian cents / liter**[38] (purchase price at the pump).

In addition to the federal regulation, some provinces such as Ontario and Quebec have established additional provincial clean fuel requirements that will further drive demand for renewable fuels; both

[38] Clean Fuel Regulations: SOR/2022-140; Canada Gazette, Part II, Volume 156, Number 14; Registration SOR/2022-140 June 21, 2022. https://www.gazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html

provinces require increasing blends of renewable liquid components[39] in diesel and gasoline; Kalibrate (2022)[40].

In addition to the CFRs, the Canadian government launched the $1.5 billion Clean Fuels Fund to de-risk the production of clean fuels like hydrogen, renewable diesel, and renewable natural gas in Canada.

British Columbia, Quebec, Alberta, Manitoba, Ontario, and Saskatchewan all either have a renewable fuel mandate, or a low carbon fuel standard which are supportive of renewable diesel and other biofuels (CER 2023)[41].

4.4.4 Greenhouse Gas Regulations

The Newfoundland Provincial Government implemented a carbon pricing system in 2019 to reduce greenhouse gas (GHG) emissions. The system includes performance standards for large industrial facilities through the *Management of Greenhouse Gas Act* and its Regulations.

Under this legislation, industrial facilities that emit 15,000 tonnes or more of GHG emissions per year are required to report their emissions on an annual basis. The Act also provides for the establishment of a GHG reduction target for industrial facilities that have either emitted 25,000 tonnes or more of GHG emissions per year in any year since Section 4 of the Act came into force or emitted 15,000 tonnes or more since Section 4 of the Act came into force and opt to be regulated by the Act.

The **Management of Greenhouse Gas Act** provides for the establishment of a fund called the Newfoundland and Labrador Greenhouse Gas Reduction Fund. Deposits into the Fund will come from the purchase of Fund credits by operators of industrial facilities, used to meet GHG emission reduction obligations and from enforcement activities under the Act and its regulations. Compliance costs for regulated facilities will increase out to 2030 due to both an annual increasing cost of carbon per tonne (set federally) and an annually increasing reduction target established under the Newfoundland legislation.

According to information provided to Stantec by Hydro, Hydro will have to buy compliance credits to meet section 9 of the act. As per the *Management of Greenhouse Gas Regulations,* the compliance cost increases each year to 2030 up to $170/tCO_2e as per the federal pricing schedule. Reduction targets from the established baseline are also increasing from 14% in 2024 to 28% below baseline by 2030[42].

[39] Diesel – renewable diesel. Gasoline – ethanol.
[40] Phase 1 Report: Preliminary and Background Market Review; November 3, 2022 Paul Pasco CLIENT-COMMERCIAL. PDF page no. 7 – 8. Report provided by Hydro.
[41] Market Snapshot: New Renewable Diesel Facilities Will Help Reduce Carbon Intensity of Fuels in Canada; 2023-05-03. https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2023/market-snapshot-new-renewable-diesel-facilities-will-help-reduce-carbon-intensity-fuels-canada.html
[42] Government of Newfoundland 2018. NLR 116/18 - Management of Greenhouse Gas Regulations under the Management of Greenhouse Gas Act (assembly.nl.ca

Based on the baseline and historical compliance cost information provided by Hydro[43], Hydro expects to have sufficient surplus performance credits (section 8) out till 2050. It was indicated that Hydro will have to buy compliance credits to meet section 9 of the Act.

We have accordingly estimated the daily compliance costs in Table 25 for operating the existing 123 MW turbine and an additional future 150 MW turbine assuming a $0 cost for any credits required under section 8 of the Act and a cost of four times the federal carbon pricing for 2030 for credits under section 9 of the Act (as suggested by Hydro). On this basis, the cost of compliance with the GHG regulations in 2030, is estimated at approximately C$230,000 per day to burn diesel in the 123 MW turbine and an additional 150 MW turbine. Estimated costs for 1, 5 and 42 days of operations are summarized in Table 24.

No	Description	Days	150 MW	123MW	Total (150 MW+123MW)
1	Cost per day	1	104,720	127,840	232,560
2	Cost for *X* days	5	523,600	639,200	1,162,800
3		42	4,398,240	5,369,280	9,767,520

42 days = 6 weeks

Table 24 Estimate of Compliance Cost (C$) under Greenhouse Gas Regulations

[43] Long Term Fuel Supply Study, Holyrood; 1st May 2024.

No	Category	Description	150 MW	123MW	Total (150 MW+123MW)	Remarks / Notes
1	-	Fuel consumed (L/d)	**969,000**	**1,181,707**	**2,150,707**	-
2	Regulatory Parameters	Regulated GHG Reduction target (tGHG:production)	28.0%	28.0%	28.0%	2030 as per Management of Greenhouse Gas Regulations
3		Section 9(4) limit on use of credits	20%	20%	20%	-
4		GHG Reduction Fund carbon price	$170	$170	$170	Federal Carbon Pricing Schedule
5		GHG Reduction Fund carbon price x4 for prescribed purchases	$680	$680	$680	As per Compliance Spreadsheet Provided by B. Sparkes
6	Facility baseline parameters	Baseline GHG emissions intensity (tGHG:production)	1.0480	1.0480	1.0480	As per Compliance Spreadsheet Provided by B. Sparkes
7		Calculated GHG reduction intensity (tGHG:production)	0.2934	0.2934	0.2934	-
8		Calculated GHG reduction limit (tGHG:production)	0.7545	0.7545	0.7545	-
9		Calculated GHG reduction intensity for section 9(4) (tGHG:production)	0.0587	0.0587	0.0587	-
10	Facility verified emissions report data	Production (t)	2,622.68	3,198.40	5,821.08	Based on unit performing at baseline GHG intensity 1.048
11		GHG emissions excluding fixed processes (tGHG)	2,748	3,352	6,100	Estimated using WCI emission factors from 2022 GHG reporting by NL Hydro WCI
12	Faciliy baseline calculations to determine regulatory compliance	Calculated emissions business as usual (production x baseline) (tGHG)	2,748	3,352	6,100	-
13		GHG reduction obligation (t GHG)	770	938	1,708	-
14		Calculated compliance emissions limit (tGHG)	1,979	2,413	4,392	-
15		Calculated Section 9(4) share of reduction obligation (tGHG)	154	188	342	-
16	Compliance Assessment - section 9(4) limit on use of credits	Actual on-site emissions change from business as usual (tGHG)	-	-	-	-
17		GHG reductions for purposes of section 9(4)	-	-	-	-
18		GHG target met (Y/N)	N	N	N	-
19		Remaining obligation (credits)	154	188	342	-
20	Compliance Assessment - section (8) target	Actual on-site emissions change from compliance limit (tGHG)	(770)	(938)	(1,708)	-
21		GHG target met (Y/N)	N	N	N	-
22		Remaining obligation (net of Section 9(4) obligation) (credits)	616	751	1,366	Please fill in corresponding green cells below
23	Section 9(4) and 9(5) compliance credits submitted	Remaining obligation (credits)	154	188	342	-
24		**Number of earned performance credits submitted (credits)**	**0**	**0**	**0**	Cannot exceed number of active credits in facility's account
25		**Number of Fund credits purchased (4x regulated price) (credits)**	**154**	**188**	**342**	Must be purchased and paid for prior to submission of compliance report
26		**Fund credits purchase cost (paid to GHG Reduction Fund)**	**$104,720**	**$127,840**	**$232,560**	Must be purchased and paid for prior to submission of compliance report
27	Section 8 compliance credits submitted (net of section 9(4) credits submitted)	Remaining obligation (net of on-site obligation) (credits)	616	751	1,366	-
28		**Number of earned performance credits submitted (credits)**	**0**	**0**	**0**	Cannot exceed number of active credits in facility's account, net of credits used in current report for section 9(4)
29		**Number of purchased performance credits submitted (credits)**	**616**	**751**	**1366**	Cannot exceed number of active credits in facility's account, including any purchases made after September 2
30		**Number of Fund credits purchased (credits)**	**0**	**0**	**0**	Must be purchased and paid for prior to submission of compliance report
31		**Fund credits purchase cost (paid to GHG Reduction Fund)**	**$0**	**$0**	**$0**	Must be purchased and paid for prior to submission of compliance report
32	Summary of sections 9(4), 9(5) and 8 credits purchased	Number of earned performance credits submitted (credits)	0	0	0	Cannot exceed number of active credits in facility's account
33		Number of purchased performance credits submitted (credits)	616	751	1366	Cannot exceed number of active credits in facility's account, including any purchases made after September 2
34		Number of Fund credits purchased (credits)	154	188	342	Must be purchased and paid for prior to submission of compliance report
35		Fund credits purchase cost per day (paid to GHG Reduction Fund)	$104,720	$127,840	**$232,560**	Must be purchased and paid for prior to submission of compliance report

Table 25 Estimate of Daily Compliance Cost in 2030 under the Management of Greenhouse Gas Regulations

In addition to the influence of the NL GHG compliance program on the Holyrood GTs operational cost, Canada's oil and gas industry is being influenced by GHG compliance programs. This includes upstream and downstream oil and gas operations which are all legislated to reduce GHG emissions through either the federal or provincial programs that have received approval as equivalent to the federal system. These programs have increased pricing out to 2030, following the federally defined price schedule which increases $15/tonne CO_2e annually, up to $170/tonne CO_2e by 2030. The programs also have increasing stringent reduction requirements, either versus facility specific benchmarks or versus high performance benchmarks established based on best in industry performance. It is noteworthy that these programs are set up to be revenue neutral, in that money collected through compliance funds is to flow back to the provinces to be used for GHG reduction activities. This includes funding for industry to complete emissions reduction projects.

4.4.5 Oil and Gas Sector Cap

ECCC has announced the regulatory framework for a Canadian Oil and Gas Sector Cap. The framework allows for increased growth post 2019 to be eligible for free allowances, has expanded the compliance mechanism options and does not include oil and gas transmission. Table 26 shows forecasted oil, natural gas, and LNG production levels in 2030 in consideration of the expected socio-economic impacts of the new cap as well as other existing legislation (including the GHG programs federally and provincially), implying ECCC expects oil and gas production in Canada to still increase to 2030.

No	Description	Units	2019 Production Levels	2030 Production Levels based on the CER's Canada Net Zero Forecast
1	Total Oil production	1,000 barrels per day	4,400	5,153
2	Oil Sands		3,126	3,730
3	Conventional oil		1,274	1,423
4	Natural gas production	Petajoules / year	7,470	7,845
5	LNG production	Billion cubic feet / day	0	3.91
Reference(s)		*Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap; https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap/regulatory-framework.html#toc2*		

Table 26 Production levels Assumed by ECCC in Developing Caps

Some highlights of the proposed framework are:

- Activities covered: LNG facilities, upstream oil and gas including offshore facilities, bitumen and other crude oil production (with some caveats), surface mining of oil sands and bitumen extraction, upgrading of bitumen / heavy oil to produce synthetic crude, production and processing of natural gas/natural gas liquids, liquified natural gas, **but not directly applicable to refineries and not applicable to imported crude oil**.
- The regulation <u>does not</u> replace the GHG Pricing Act and associated federal and provincial regulations which already put compliance costs on carbon associated with oil and gas facilities. This new cap would be on top of the various output-based pricing systems and Clean Fuel Standards already ongoing.
- There will be a requirement to register and in the following years to submit a compliance report.
- Registration is required in 2025. 2026 is the first compliance year with phase in from 2026 to 2030.

- Comments on the framework were due by February 5, 2024, draft regulations are to be published in Part 1 of the Gazette in 2024 with final regulations in 2025.

4.4.6 Summary of Canadian Regulatory Influences

Canada's Electric Vehicle Availability Standard

Canada's EV targets are ambitious and may not be as achievable to the extent that seems to be suggested due to a lack of primary power generation and electrical distribution needed to transport electrons to point of use - charging.

How EV penetration into the Canadian fleet will look like across the decades through 2050 and in specific geographies is a detailed study unto itself and subject to numerous interrelated events and projects spoken to and still to be realized. Medium to long-term forecasts would be speculative at best. However, as regards the continued availability of diesel or a similar hydrocarbon for use at Holyrood, the listed sections below when read collectively should provide Hydro with a historical appreciation of dynamics in the crude oil and refining sector - how the sector is adapting for the future - meaning that refiners, technologies, fuel types will as they always have, continue to evolve with some staying longer than others, but essentially producers will continue seek to address the needs of the market and ultimately the customer.

- Section 4.1: An Overview of Canada's Refining Sector page 9,
- Section 4.2: An Overview of US Refining Sector page 32, and
- Section 6.2: Refinery conversions / redundancy / closures: as function of the energy transition, supply volatility page 89.

Clean Electricity Regulations

The Clean Electricity Regulations are expected to increase the cost of generating electricity via fossil fuels after 2035 as generation with emissions beyond the allowable GHG threshold will require credits or offsets. A summary of the estimated cost of compliance in 2030 based on current regulations for the 123MW and 150MW GT as function of key assumptions are reported in Table 23 page 49.

The Clean Electricity Regulations will increase demand for renewable fuels to be used at traditional generating stations after 2035 where power producers seek to continue to operate units traditionally fueled by fossil fuels. With the current limited supply of renewable fuels on the market and expected increased demands for renewable fuels for transportation and power generation as well as industrial users under existing and potential new regulations, supply of biogenic fuels may fall below demand; in which case credits or other offsets would need to be purchased.

Clean Fuel Regulations

The Clean Fuel Regulations' output-based pricing system regulations for GHG reductions, federally and provincially along with corporate commitments to emission reductions, are creating incentive for oil and gas producers and processors to reduce GHG emissions and to also potentially produce renewable fuels for growing demand. These regulations will increase the cost of fossil fuels over time, however there are also opportunities for businesses to offset some of this lost revenue via application for funding of low carbon projects such as carbon capture and storage or conversion to use renewable fuels.

GHG Regulations

A summary of the estimated cost of compliance in 2030 based on current regulations for the 123MW and 150MW GT as function of key assumptions are reported in Table 24 page 52; more detail is available in Table 25 page 53. Depending on the availability of credits and the ability of the units to operate below the baseline, compliance costs could vary however there are both increasing cost of carbon and reduction targets that will influence compliance costs for the units. Beyond 2030 it is expected that further reductions and higher carbon costs may apply.

In addition to the GHG compliance requirements at Holyrood potentially influencing fuel choice and influencing operating costs, these GHG programs will also continue to influence Canadian oil and gas producers to consider the cost of continued GHG emissions in their business planning.

Oil and Gas Sector Cap

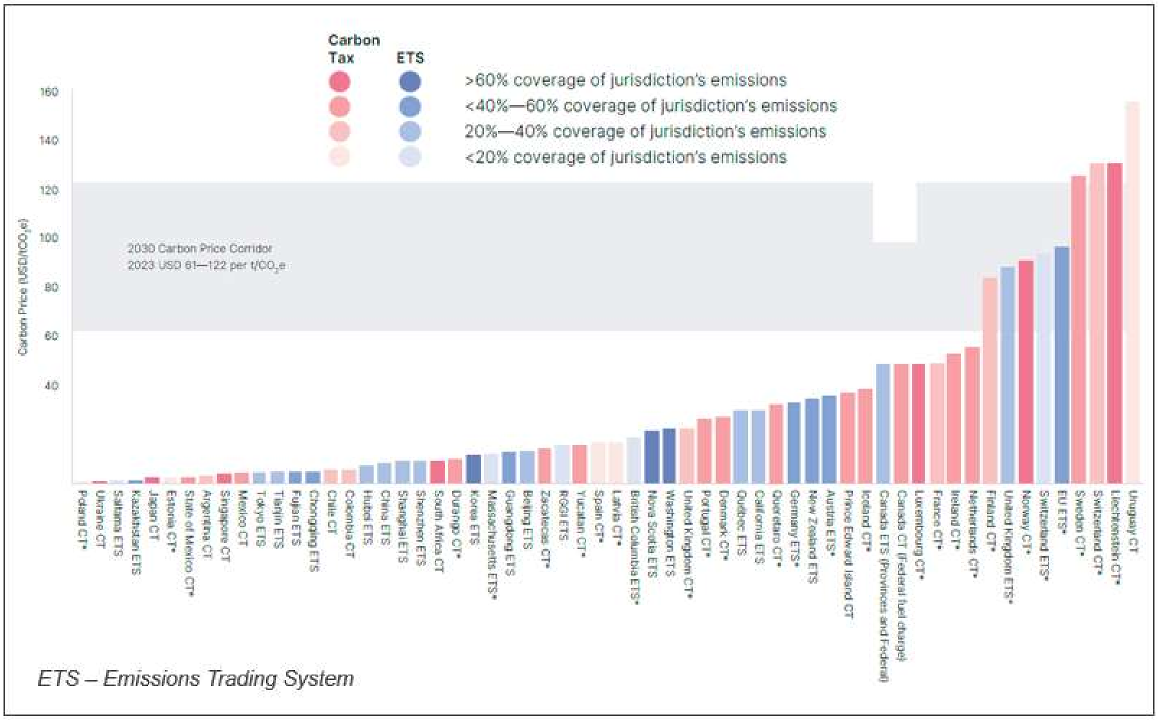
The proposed federal oil and gas cap if it becomes law, will be further financial incentive for fossil fuel producers and refineries to take on significant projects to reduce emissions from oil and gas production or alternatively to consider to exit the fossil fuel business beyond 2030 as carbon costs and program complexities (reporting under multiple programs with different compliance costs and mechanisms) will continue to increase.

The cap as it presently exists, speaks specifically to the production of fossil resources (natural gas, oil sands); it is not directly applicable to refineries nor refining of imported crude oil. Other than a carbon pollution tax increasing from C$80 in 2024-2025, to C$170 / metric tonne in 2030 (under federal and provincial GHG programs), refiners should be expected to continue operating.

4.5 REGULATION IN US

Introduction

The US lags Canada and various European countries in imposing direct carbon pollution regulation, emissions trading systems (ETS) or similar pricing mechanisms; see Figure 26.



Reference: State and Trends of Carbon Pricing 2023. Work Bank Group. PDF Page no. 21.
https://openknowledge.worldbank.org/entities/publication/58f2a409-9bb7-4ee6-899d-be47835c838f

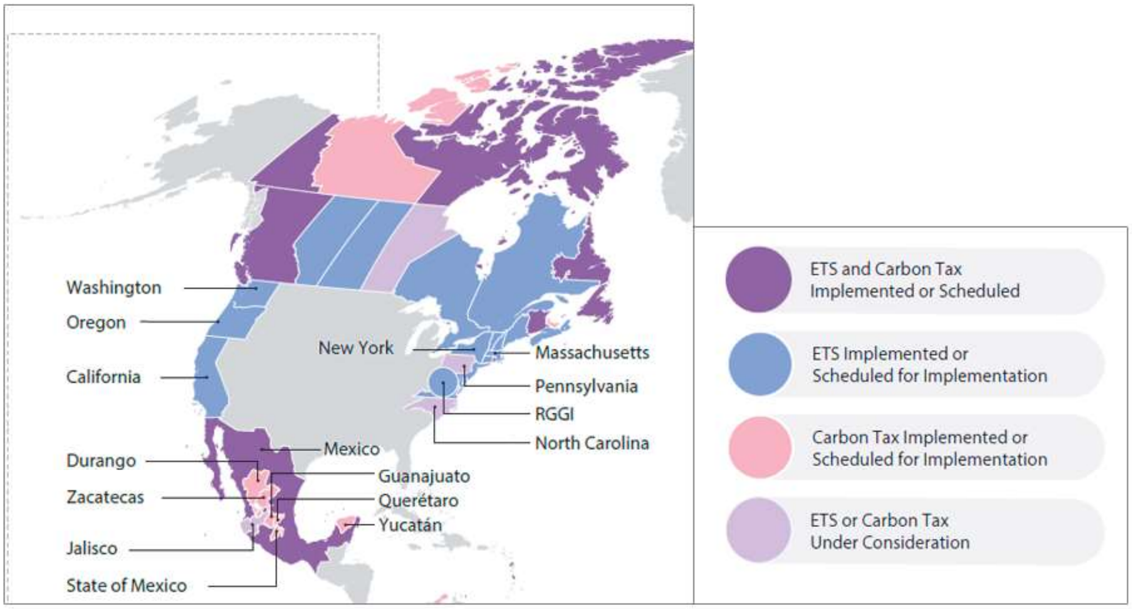
Figure 26 Carbon Pricing – Prices and Coverage (World Bank 2023)

According to the World Bank's[44] 2023 report on carbon pricing, approximately 23% of the world's GHG emissions are under some sort of pricing program or ETS. Most existing instruments are in high-income countries in North America and Europe at either national, subnational, or regional level. There is only one instrument in the Middle East and Africa regions. Several countries of the latter are exploring options and taking preparatory steps.

Interest from emerging economies is driven by the need for climate change mitigation policy, but also managing transition risks, exploring revenue opportunities, and preparing for EU accession.

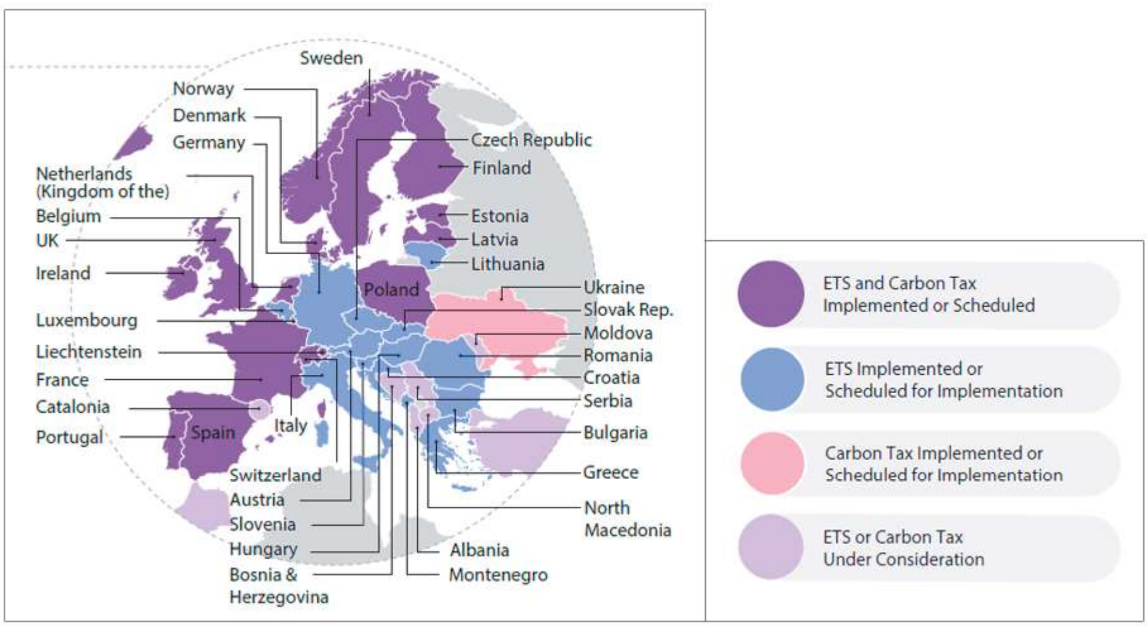
Figure 27 to Figure 29 shows the status of carbon pricing globally.

[44] State and Trends of Carbon Pricing 2023. Work Bank Group. PDF Page no. 23. https://openknowledge.worldbank.org/entities/publication/58f2a409-9bb7-4ee6-899d-be47835c838f



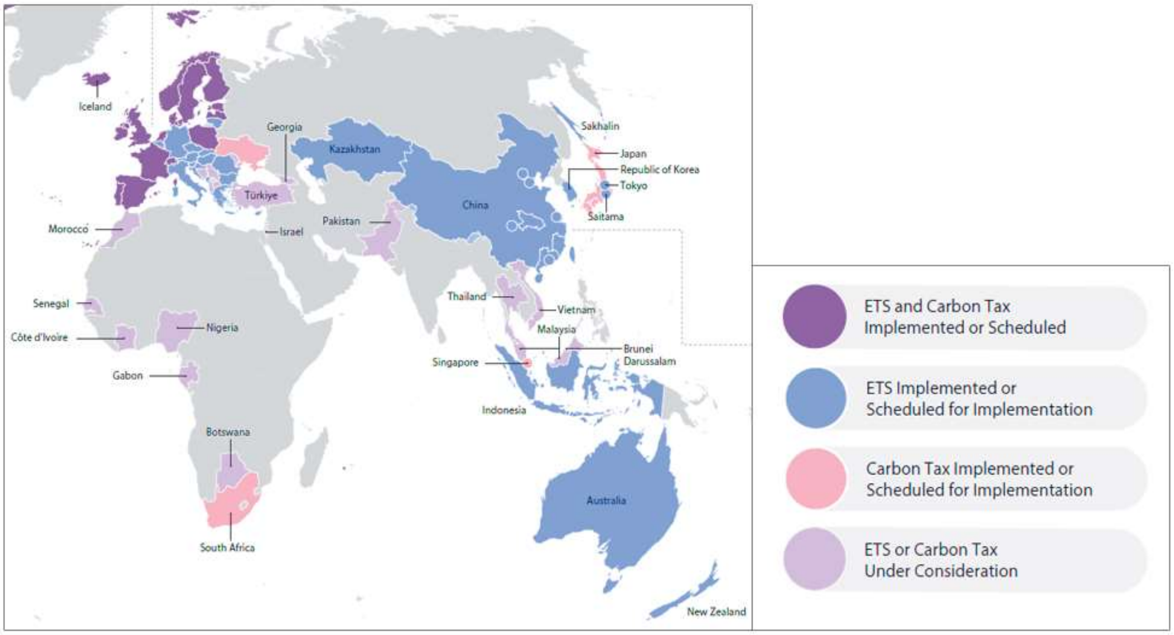
Reference: State and Trends of Carbon Pricing 2023. Work Bank Group. PDF Page no. 23. https://openknowledge.worldbank.org/entities/publication/58f2a409-9bb7-4ee6-899d-be47835c838f

Figure 27 (a) Global Carbon Pricing Schemes (World Bank 2023)



Reference: State and Trends of Carbon Pricing 2023. Work Bank Group. PDF Page no. 23. https://openknowledge.worldbank.org/entities/publication/58f2a409-9bb7-4ee6-899d-be47835c838f

Figure 28 (b) Global Carbon Pricing Schemes (World Bank 2023)



Reference: State and Trends of Carbon Pricing 2023. Work Bank Group. PDF Page no. 23. https://openknowledge.worldbank.org/entities/publication/58f2a409-9bb7-4ee6-899d-be47835c838f

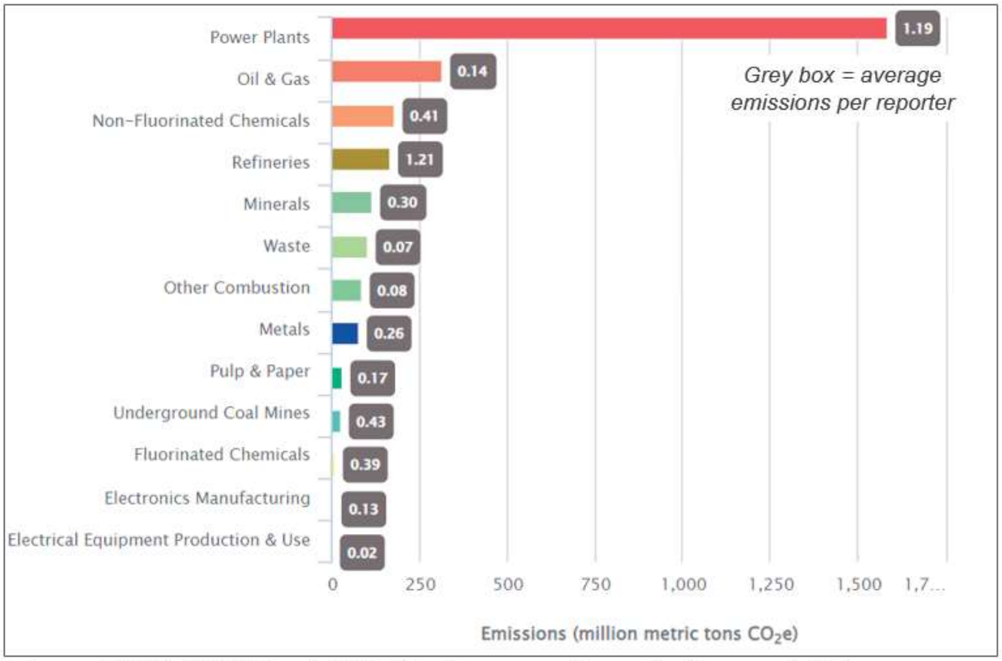
Figure 29 (c) Global Carbon Pricing Schemes (World Bank 2023)

President Biden has set an ambitious US goal of achieving a carbon pollution-free power sector by 2035 and net zero emissions economy by no later than 2050. The US, under Biden, has committed to cutting emissions 50-52% of 2005 levels by 2030 under the Paris climate accord. Most US emission reductions in the coming years are expected to come from power plants – said sector is the target for most existing carbon pricing programs. Reductions are expected to increase further due to the passage of the Inflation Reduction Act (IRA). The latter provides US$369 billion in clean energy incentives and is designed to remove economic barriers for solar and wind facilities. The IRA does not include requirements that utilities reduce emissions from fossil fuel power plants or any carbon pollution pricing.

There is a federal GHG reporting program - the Greenhouse Gas Reporting Program (GHGRP) - this is purely a reporting program; it does not impose emissions limits or mandate reductions.

Established in 2009 by the US Environmental Protection Agency (EPA), the GHGRP is a mandatory federal emissions reporting program and requires high-emitting companies to report their facility GHG emissions. Facilities must report if they emit >25,000 metric tons GHG per year, those emitting less than this number are not impacted by the GHGRP. Top 5 emitters[45] (listed by highest emissions) by sector are: power plants, oil & gas, chemicals, refineries, minerals and waste; see Figure 30.

[45] US EPA; GHGRP Reported Data. https://www.epa.gov/ghgreporting/ghgrp-reported-data.



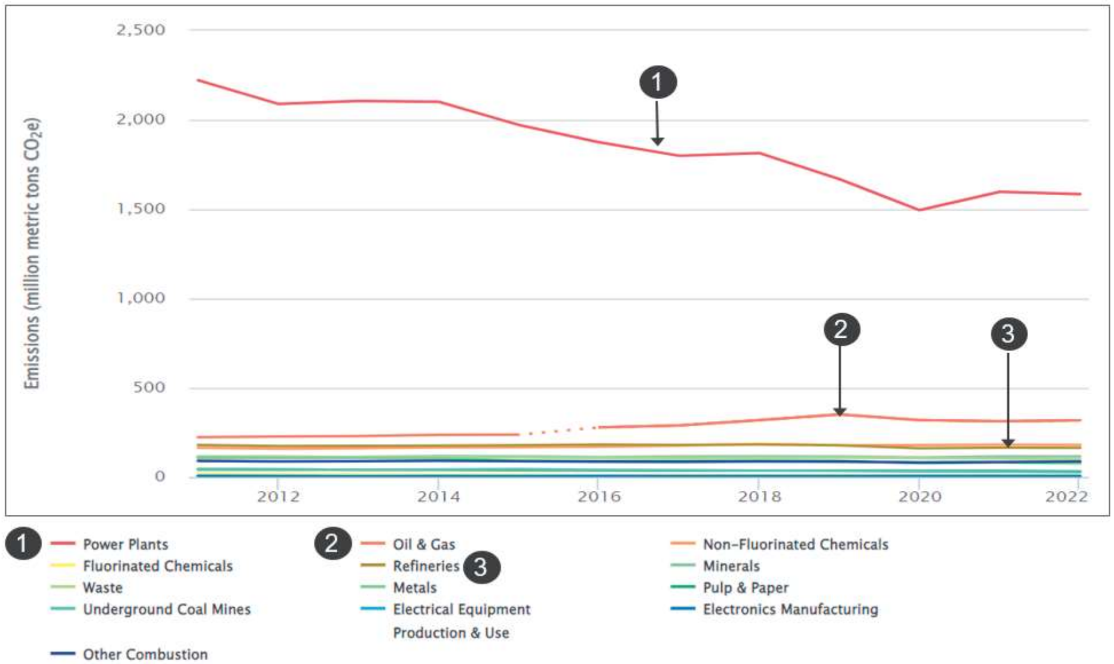
Reference: US EPA; GHGRP Reported Data. https://www.epa.gov/ghgreporting/ghgrp-reported-data.

Figure 30 US Direct GHG Emissions by Sector (2022)

In 2022 just over 7,500 US facilities reported their annual emissions to GHGRP; see Table 27. Power dominates 59% of emissions with refineries following at 6% for 1,332 and 135 facilities respectively. Tabled data along with Figure 31, clearly shows why carbon reduction in the power sector is a key focus for reducing GHG emissions in the US. Not to say that refining should not receive attention, but it may be argued that for reason of percentage share and strategic importance, it is somewhat less of a priority and may receive less attention.

No	Description	Power Plants	Petroleum & Natural Gas Systems	Refineries	Chemicals	Other	Minerals	Waste	Metals	Pulp & Paper	Total
1	2022 GHG Emissions ((Million Metric Tons CO2e)	1,585	316	164	186	121	114	101	77	31	**2,695**
2	% Share	59%	12%	6%	7%	4%	4%	4%	3%	1%	100%
3	# of Reporting Facilities	1,332	2,330	135	459	1,357	377	1,452	293	188	**7,586**
2	% Share	18%	31%	2%	6%	18%	5%	19%	4%	2%	100%
Reference(s)	*US EPA; GHGRP Reported Data. https://ghgdata.epa.gov/ghgp/main.do#/listFacility/*										

Table 27 US Direct GHG Emissions by Sector (2022)



Reference: US EPA; GHGRP Reported Data. https://www.epa.gov/ghgreporting/ghgrp-reported-data.

Figure 31 US Direct GHG Emissions by Sector (2012 to 2022)

US refinery emissions in 2022 by state and PADD are reported in Table 28 and Table 29 respectively. Texas not surprisingly accounts for 34% of the 116 million tons CO_{2eq} emitted and reflects their having the highest number of refineries by state at 32 of 133; Table 18 page 36.

No	State	2022 GHG Emissions Million metric Tons CO_{2eq}	% Share
1	Alabama	1,103,624	1.0%
2	Alaska	1,111,989	1.0%
3	Arkansas	563,487	0.5%
4	California	16,284,582	14.1%
5	Colorado	487,685	0.4%
6	Delaware	2,174,721	1.9%
7	Hawaii	491,522	0.4%
8	Idaho	0	0.0%
9	Illinois	5,874,557	5.1%
10	Indiana	2,418,293	2.1%
11	Iowa	0	0.0%
12	Kansas	2,393,232	2.1%
13	Kentucky	1,456,167	1.3%
14	Louisiana	18,931,366	16.4%
15	Michigan	625,839	0.5%
16	Minnesota	2,337,194	2.0%
17	Mississippi	3,322,190	2.9%
18	Missouri	0	0.0%
19	Montana	1,285,804	1.1%
20	Nebraska	0	0.0%
21	Nevada	16,161	0.0%
22	New Jersey	1,516,920	1.3%
23	New Mexico	531,499	0.5%
24	New York	0	0.0%
25	North Dakota	433,181	0.4%
26	Ohio	2,754,455	2.4%
27	Oklahoma	3,185,235	2.8%
28	Oregon	0	0.0%
29	Pennsylvania	1,301,077	1.1%
30	South Dakota	0	0.0%
31	Tennessee	597,946	0.5%
32	Texas	38,703,191	33.6%
33	Utah	1,229,523	1.1%
34	Washington	3,978,028	3.4%
35	West Virginia	198,088	0.2%
36	Wisconsin	31,849	0.0%
37	Total	115,339,405	100.0%

Reference(s)	*US EPA; GHGRP Reported Data. Data Extracted from EPA's FLIGHT Tool (http://ghgdata.epa.gov/ghgp)*

No. of Reporting entities - 133

Table 28 US Refinery Emissions by State (2022)

No	PAD District / State	No. Operable Refineries			2022 GHG Emissions Million metric tons CO_{2eq}	% Share
		Total	Operating	Idle [(a)]		
1	PADD I	7	7	-	5,190,806	5.5%
2	Delaware	1	1	-	2,174,721	
3	New Jersey	2	2	-	1,516,920	
4	Pennsylvania	3	3	-	1,301,077	
5	West Virginia	1	1	-	198,088	
6	PADD II	25	22	3	22,162,452	23.7%
7	Illinois	4	4	-	5,874,557	
8	Indiana	2	2	-	2,418,293	
9	Kansas	3	3	-	2,393,232	
10	Kentucky	1	1	-	1,456,167	
11	Michigan	1	1	-	625,839	
12	Minnesota	2	2	-	2,337,194	
13	Dakota	1	1	-	487,685	
14	Ohio	4	3	1	2,754,455	
15	Oklahoma	5	4	1	3,185,235	
16	Tennessee	1	1	-	597,946	
17	Wisconsin	1	-	1	31,849	
18	PADD III	56	56	-	63,155,357	67.5%
19	Alabama	3	3	-	1,103,624	
20	Arkansas	2	2	-	563,487	
21	Louisiana	15	15	-	18,931,366	
22	Mississippi	3	3	-	3,322,190	
23	New Mexico	1	1	-	531,499	
24	Texas	32	32	-	38,703,191	
25	PADD IV	15	13	2	3,034,861	3.2%
26	Colorado	2	-	2	487,685	
27	Montana	4	4	-	1,285,804	
28	Utah	5	5	-	1,229,523	
29	Wyoming	4	4	-	31,849	
30	PADD V	26	26	-	21,882,282	23.4%
31	Alaska	5	5	-	1,111,989	
32	California	14	14	-	16,284,582	
33	Hawaii	1	1	-	491,522	
34	Nevada	1	1	-	16,161	
35	Washington	5	5	-	3,978,028	
36	Total	129	124	5	93,543,476	100%

Table 29 US Refinery Emissions by PADD (2022)

Carbon Pollution Pricing / Taxation in the US – Past / Present and Future Outlook

In recent history and when compared to Canada, less countenance has been given toward carbon taxation / pollution pricing in the US at state and federal level. Figure 27 page 58 shows states that currently have some form of GHG program including carbon pricing. Most of these programs do not apply to oil refineries. California is the only state that regulates GHG emissions from refining.

The US is starting to set a path to achieve climate change action goals. Country-wide carbon pricing is however, not currently on the table.

As of 2023, 13 states have active carbon-pricing programs, but only targeting power generation on the east coast. California, Washington and Oregon have more broad carbon pricing systems while 11 Northeast states — Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia — make up the Regional Greenhouse Gas Initiative (RGGI). RGGI is the first mandatory cap-and-trade program in the US to limit CO_2 emissions from the power sector. California's program was the first multi-sector cap-and-trade program in North America. Massachusetts has also implemented regulations to establish an additional cap-and-trade program for its power sector that runs in parallel with RGGI and extends to 2050. Washington state recently enacted new cap-and-invest legislation that took effect in 2023. New York is preparing an economy-wide cap-and-invest program that is expected to launch in 2025, either in addition to its RGGI participation or in place of its RGGI participation.

In 2023, the US released a new National Innovation Pathway Report, highlighting the Biden-Harris Administration's strategy for accelerating key clean energy technology innovations. The Administration is advancing a three-pronged approach that prioritizes innovation, demonstration, and deployment to scale the technologies the US needs to achieve its goals of a carbon pollution-free electricity sector by no later than 2035 and a net-zero emissions economy by no later than 2050.

There are no caps on oil and gas GHG emissions federally, there is however a proposed methane fee (Waste Emissions Charge discussed in the next paragraph) incentivizing oil and gas companies to reduce methane (a powerful GHG) emissions. The US EPA is partnering with the US Department of Energy (DOE) to use resources provided by Congress in the IRA to provide over US$1 billion dollars in financial and technical assistance to accelerate the transition to no- and low emitting oil and gas technologies, including funds for activities associated with low-producing conventional wells, support for methane monitoring, and funding to help reduce methane emissions from oil and gas operations.

The EPA is working with industry and other stakeholders to improve the GHGRP and increase the accuracy of reported methane emissions. The EPA seeks to encourage facilities with high methane emissions to meet or exceed performance levels set by Congress – performance that is already being achieved by leading oil and gas companies. The IRA established a Waste Emissions Charge (WEC) for methane from oil and gas facilities reporting emissions >25,000 metric tons of CO_{2eq} per year to the GHGRP. As directed by Congress, the WEC starts at US$900/metric tonne wasteful emissions in 2024, increasing to US$1,200 for 2025 and US$1,500 for 2026 and beyond; WEC only applies to emissions that exceed the statutorily specified levels. For comparison purposes, US$1,500/tonne of methane equates to US$60/tonne CO_{2eq} using a global warming potential of 25, it however, only targets methane venting and flaring, not overall emissions or any other GHG emission types or sources.

EPA's proposed rule addresses details regarding how the charge will be implemented, including the calculation of the charge and how exemptions from the charge will be applied. Facilities in compliance with the recently finalized Clean Air Act standards for oil and gas operations would be exempt from the charge after criteria set by Congress are met. EPA expects that over time, fewer facilities will face the charge as they reduce wasteful emissions and become eligible for this regulatory compliance exemption.

Inflation Reduction Act (IRA) and Electric Vehicles

The IRA contains new and expanded tax credits for drivers to purchase new EVs, as well as the first-ever tax credits for purchasing used EVs vehicles. These tax provisions will help make EVs more accessible and affordable whilst incentivizing automakers to build supply chains for the critical minerals and batteries contained in those vehicles. The Act also includes tax credits and incentives for oil and gas decarbonization, including CCS.

Renewable Fuels Standard, State Fuel Standards

The US renewable fuel standard (RFS) has been in place since 2005, it requires a minimum volume of renewable fuel as part of transportation fuels. On June 21, 2023, the US EPA announced a final rule to establish biofuel volume requirements and associated percentage standards for cellulosic biofuel, biomass-based diesel (BBD), advanced biofuel, and total renewable fuel for 2023–2025.

The final rule includes steady growth of biofuels for use in the nation's fuel supply for 2023, 2024, and 2025. The Energy Independence and Security Act (EISA, 2007[46]) does not specify statutory volumes after 2022; EPA in this rule is establishing final biofuel volume targets for all categories under the "set" authority. When determining biofuel volumes after 2022, EPA must consider a variety of factors specified in the statute, including costs, air quality, climate change, implementation of the program to date, energy security, infrastructure issues, commodity prices, water quality, and supply.

Despite these efforts, advanced biofuel production have fallen short. The target for 2021 established in 2007 was 17.5 billion gallons of which 13.5 billion gallons was to be cellulosic (EPA has consistently waived that requirement). Actual production was just over 5 billion gallons, of which less than 600 million was cellulosic; WRI 2023[47].

California's Low Carbon Fuel Standard (LCFS) takes a different approach to incentivizing alternative fuels with lower CI than conventional gasoline or diesel fuel, Oregon and Washington have adopted similar programs - these are similar to the Canadian CFRs. The LCFS gives fuels sold in California a CI score based on their lifecycle GHG emissions and establishes a benchmark CI that declines over time. The benchmarks aim to reduce the CI of California fuels by 10% relative to the CI of gasoline and diesel by 2022 and by 20% by 2030.

All fuel providers in California must meet the CI benchmark every year. Providers with deficits buy credits, increasing the cost of higher-carbon fuels. Producers of low-carbon fuels can sell the credits they earn, giving them an added revenue stream. These incentives help bring low-carbon fuels, including electricity for EVs, into the Californian market. In 2022, the CI of California's transportation fuels was 12.6% below the 2010 baseline, exceeding the 10% reduction target; WRI 2023[47].

[46] Final Renewable Fuels Standards Rule for 2023, 2024, and 2025 | US EPA. https://www.epa.gov/renewable-fuel-standard-program/final-renewable-fuels-standards-rule-2023-2024-and-2025
[47] U.S. Policies for Reducing Emissions from Transportation | World Resources Institute (wri.org)

There has been discussion of a federal LCFS to replace the current RFS program. The EPA projects that, under the new proposed standards, EVs could account for 67% of new LDV sales and 46% of new medium-duty vehicle sales in model year 2032.

The US under Biden has a target that by 2030 over 50% of LDV and at least 30% of medium- and heavy-duty vehicles sold globally will be zero-emissions vehicles e.g., battery electric, fuel cell electric, and plug-in hybrid vehicles; US Government 2023[48].

4.5.1 Summary of US Regulatory Influences

The extent of carbon pricing in the US is not expected to strongly influence oil refinery operations there to 2030 as indication is for a focus on reducing GHG intensity from power generators.

Beyond 2030 however, there could be new pressure on oil / gas producers and conventional fossil-based refiners, as global commitments to net zero by 2050 will mean ongoing review of policy effectiveness in meeting GHG reduction targets. Targets and funding for EV uptake and increased production of low carbon fuels may affect availability and pricing of regular diesel from the US.

Despite best efforts to reduce emissions in the transport sector by electrification of the vehicle pool with a knock-on effect to the demand for diesel (and gasoline), the strategic importance of the US refining and downstream petrochemical sector to the economy along with international security, should not be underestimated, to the extent that both sectors can be expected to be somewhat shielded from decarbonization policies at large. For this reason, we do not see medium and possibly longer-term risk to production of diesel in the US.

4.6 SUMMARY

Canada Refining Sector in the Future

The Canadian oil and gas sector and allied industry of refining is coming under increasing structural pressures both directly and indirectly (carbon pollution pricing, access to domestic crude, capped growth), that may in the longer-term cause refiners to consider reducing capacity or to exit the market at least in terms of production. Sites may be reconfigured to inbound TS&D of those products for which markets remain.

Factors that need to be taken into the equation when considering the future of Canada' refinery sector is the size and age of Canadian refineries relative to competing jurisdictions, and where the industry sees that its future markets lie in terms of the products they currently, could or cannot produce due to general circumstance. Refineries in Australia, Europe and South Africa by example have found themselves facing a similar situation – built before, during or soon after World War II their refineries are older and of questionable scale relative to Asia and the Middle East's export directed refineries – where this does not

[48] Fact sheet: President Biden to Catalyze Global Climate Action through the Major Economies Forum on Energy and Climate | The White House. https://www.whitehouse.gov/briefing-room/statements-releases/2023/04/20/fact-sheet-president-biden-to-catalyze-global-climate-action-through-the-major-economies-forum-on-energy-and-climate/

easily justify capital to expand and or retrofit to meet increasingly complex environmental processes and regulations.

Refiners' primarily producing liquid transport fuels in a decarbonizing era must ultimately ask - when do I close? As individual circumstances dictate, not all will close at the same time. Staying operational will depend primarily on what market a refiner may direct its business profitably to.

US Refining Sector in the Future

The US refining sector is considerably larger than Canada's and, in some states, faced with circumstances not too dissimilar to that of the Canadian sector.

On numerous other metrics and qualitative considerations however, deeper comparison will demonstrate the two countries sectors differ significantly, and as consequence the outlook for US refiners if not positive, is at least optimistically neutral for continued operations through 2050.

The strategic importance of the US refining and downstream petrochemical sector to the US economy along with international security should not be underestimated, to the extent that both sectors can be expected to be somewhat shielded from decarbonization initiatives at large, at least until a viable substitution has been defined, built and proven. For this reason, we do not see medium and longer-term risk to the production of diesel in the US.

5 PART 2: REVIEW OF EXISTING HYDRO SUPPLY CHAIN PROCESSES

The following considers transport, supply and distribution (TS&D) of diesel as follows:

- Section 5.1: Introduction
- Section 5.2: An overview of the current contracting strategy and schedule,
- Section 5.3: Asset utilization and opportunities,
- Section 5.4: Inventory management,
- Section 5.5: Supply chain alternatives,
- Section 5.6: Assessment of No.2 Diesel availability,
- Section 5.7: Risk Review, and
- Section 5.8: Summary with recommendations.

5.1 INTRODUCTION

In absence of a provided supply chain process to review, we have extrapolated process points from the RFP documents and available historic bid documents. For this exercise, "supply" has been broken into four subcategories each of which have separate supply management considerations. On-Island Supply, Off-Island Supply, Contracted, and Non-Contracted supply categories all play into examining the future supply of diesel – these categories and related considerations will be covered in this section.

Consolidation of refineries and the shift of supply via terminals, Canadian clean energy mandates, and the consumer move to hybrid or full light EVs is forecasted to reduce the number of refiners and or fuel suppliers active in the Canadian market either through market exit or via mergers as we move toward 2050. At the macro level, the study has indicated that No. 2 Diesel or suitable replacement fuels (some possibly still fossil based) will continue to be available, but at a premium price point with an adapted contracting strategy as the market moves away from refinery direct procurement, toward a more terminal oriented supply chain structure.

5.2 DELIVERY TIME (FUEL RECEIPTS): OVERALL CONTRACTING STRATEGY, SCHEDULE

The 123 MW Holyrood GT came operational in 2015. Initiated via public tender through the Newfoundland Hydro website, supplies of diesel are currently secured through a four-year contract cycle. Request for proposals (RFPs) are requested a year in advance of contract award. Bidder and award history of the past three cycles are shown in Table 30.

No	Awarded in	Contract period	Bidders	Award	Remarks
1	2014	2015-2018	North Atlantic Refining	✓	-
			Western Petroleum	-	-
			Valero	-	-
2	2018	2019-2023	North Atlantic Refining	✓	Only company to submit bids for 123MW turbine (Holyrood)*
3			Western Petroleum	-	-
4			Woodward's Oil Limited	-	-
5	2023	2024-2028	North Atlantic Refining	✓	Only company to submit bids for 123MW turbine (Holyrood)*

Reference(s)
** e-mail correspondence from B Sparkes Feb 12,2024*

Note: *As of March 2024, it is believed the Valero Terminal located approximately 10 kilometers from Holyrood Gas Turbine is no longer operational with tanks expected to be demolished in the immediate future.*

Table 30 Supply Contracts: Bidder and Award History

The bid history identifies potential issues with the current supplier pool for the volumes of diesel required for Holyrood such as low bidder response, bidders no longer operating in the region (e.g. Valero Terminal in Holyrood) and the absence of bids from on-island terminal operators such as Irving or Imperial Oil. We are already seeing shifts in the on-island distribution with Braya Renewables shifting to an export business model[49], and North Atlantic's move to transition its home heating business to smaller distributors in February 2024[50]. If this shift is viewed through the lens of reducing on-island demand, it indicates a substantial risk of a smaller bidder pool moving forward.

It is our assumption that North Atlantic Refining's (NARL) marketing arm - NARL Marketing Limited Partnership – is responsible for the 2024-2028 contract. It is assumed that diesel will be imported / received at the CBC marine terminal and delivered by road to Holyrood, Figure 32.

[49] Come By Chance refinery sold, will become biofuel operation by mid-2022
https://www.cbc.ca/news/canada/newfoundland-labrador/nl-north-atlantic-refinery-1.6267625
[50] Important Notice Regarding Home Heat; https://northatlantic.ca/home-heat-transition/

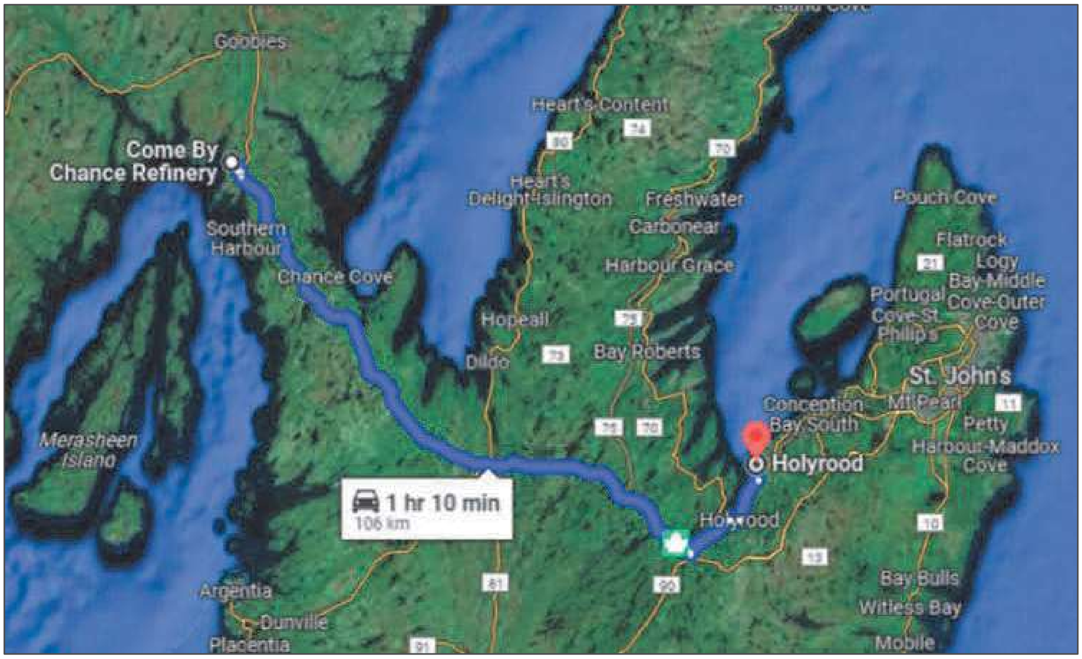


Figure 32 Come-By-Chance Refinery to Holyrood Thermal Station

It is not known which companies or ships have brought diesel to Newfoundland previously and which has ended up being supplied to Holyrood. Table 31 lists companies identified by Kent Consulting (2017) as having export and import activities in Newfoundland and Labrador. Terminals are listed in Table 32.

No	Company	Head Office	Fleet (tankers)	Capacity		Remarks
				Barrels	Liters	
1	Algoma Tankers	St. Catherine's ON	6	545,166	86,674,307	-
2	Coastal Shipping Ltd.	Lewisporte, NFLD	4	427,679	67,995,401	Part of Woodward Group [(a)]
3	Irving Oil	ST. John NB	2 (domestic) 4 (foreign)	222,000	35,295,114	Each 37,000 DWT "handy size"
4	Rigel Shipping	Shediac Cape NB	3	198,129	31,499,935	-

Reference(s)
2016 Report – Canada's Downstream Logistical Infrastructure: Refining, Biofuel Plants, Pipelines, Terminals, Bulk Plants & Cardlocks Kent Consulting, Nov. 2017. https://www.canadianfuels.ca/wp-content/uploads/2020/09/Report-OverviewofCanada-sLogisticalInfrastructure.pdf

(a) Woodward Group - https://www.woodwardgroup.ca/marine-group.html
Barrels to liters = 158.987 *DWT - Deadweight tonnage*

Table 31 East Coast Shippers (Canadian)

No	Company	Location	Interest Rating (L,MH)
1	Irving Oil Terminals	Saint-John's	M
2	Marine Atlantic Inc.	Channel-Port aux Basques	L
2	Valero Energy Inc.	Holyrood	H
3	Valero Energy Inc.	Corner Brook	L
4	Woodward's Oil Ltd.	Lewsisporte	L
Reference(s)		*TankTerminals.com Demo*	

Table 32 Newfoundland Fuel Terminals

A minimum of five-days of supply for the 123MW GT is currently stored at Holyrood as mandated by the System Operator; with the additional 150MW unit coming online an inventory management process / strategy will need to be developed. Lifecycle planning accounting for the initial purchase investment, tank-farm expansion or retrofits, fuel preservation, and disposal processes for expired diesel will have to be identified and weighted into the contracting strategy. A strategy focused on carrying higher volumes in utility owned tank farms is likely to attract more suppliers, whilst a supplier managed / access inventory strategy is likely to be appealing to on-island suppliers where existing relationships can be leveraged.

In order to map out current and possibly future contracting strategies and schedules, there are four categories of supply that should be considered:

- On-Island Supply: Total fuel supply available (owned and non-owned) on the island
- Off-Island Supply: Fuel supply available through regional or global markets
- Contracted Supply: Directly contracted supply, either on-island or off-island
- Non-Contracted Supply: Access to fuel available on demand, either on-island or off-island

On-island supply requires further study to identify owned and non-owned stored supply across the island to gauge supply that may be accessible in an emergency situation. Stantec has attempted to obtain rough numbers in this regard but the information is not readily available. This study should look at provincial strategic reserves, commercial installations such as the Come By Chance refinery, gas bars, and industrial diesel consumers with on-site storage facilities. The accessible on-island supply dictates timeframes for engaging with off-island contracted or non-contracted suppliers for fuel supply replenishment.

Off-island supply, both contracted and non-contracted [spot], has become global in nature limited only by tanker transportation timeframes and ability to accept stock at port. Larger volumes coming in may stress on-island storage facilities and road transportation resources. Off-island supply is predicted to move from refiners in the region (Eastern Canada, Atlantic Canada) to distribution terminals in Canada, the US, and even Europe or Africa.

Contracted supply, depending on the supplier, will have similar logistic considerations as noted in off-island supply. Transportation of large volumes of fuel should be spread across longer time periods where possible to accommodate trucking availability on-island. If following an owner managed storage model, fuel could be brought in over the spring / summer months. If following a Just-in-time model, port and storage facilities will have to be able to handle bulk shipments as needed.

Non-contracted supply is viewed as a contingency or backup supply for the worst-case scenario where on-island contracted fuel is not available in quantities sufficient to carry Hydro until additional contracted fuel can be delivered to Holyrood. This supply would be accessed either by commandeering fuel reserves available on island, or by ad-hoc purchases from non-contracted suppliers.

Historically, Hydro's RFP requests have resulted in a maximum of three proposals; in the medium to longer term toward 2050, this may be a significant risk should refineries in North America shutter or convert to terminals. These terminal models are supplied through the global market which adds geopolitical concerns into the mix. Recently the war in Ukraine resulted in fuel market shifts in the European Union from Russian fuel, to US and Saudi, UAE, and Kuwait fuel sources[51]. Domestic government regulations aiming to further restrict the consumer fossil fuel markets, the resulting market reduction as consumers make the shift to hybrids/ EV and equipment, and the lack of appetite for investing in refinery expansion or updates, is anticipated to further reduce supplier responsiveness. In such an environment, the supplier pool should be bolstered to ensure competitive pricing and fuel availability.

Reviewing the contract example provided by Hydro, Stantec has identified Volume[s] and Logistics[52] requests which may be limiting RFP responses:

Volumes – Looking at the Holyrood GTs, the estimated annual diesel requirement assuming 42 days of operations[53] is 90 million liters or 568,000 bbls with 5 million liters of storage available (31,449 barrels); Table 33. Using Table 31 as reference, a mismatch in circumstances and service offering could be an obstacle when attracting off-island suppliers. (Note: contract totals include Hardwoods, Stephenville, Holyrood Generation Station).

No	Description	Capacity (MW)	Liters	Bbl.	Kg
1	Holyrood gas turbine - existing [(a)]	123	40,698,000	255,983	34,593,300
2	Holyrood gas turbine - proposed	150	49,631,707	312,175	42,186,951
3	Total site capacity	273	90,329,707	568,158	76,780,251
4	*Holyrood gas turbine - future*	*300*	*99,263,415*	*624,349*	*84,373,902*
5	*Total site capacity*	*573*	*189,593,122*	*1,192,507*	*161,154,154*

Assumption(s)	
Requirement (weeks)	*6*
Days	*42*

Table 33 Holyrood Gas Turbines – Annual Diesel Demand (assumption)

[51] Outlook 2023: EU diesel demand begins to shift away from Russia; Paragraph 10; Reid I'Anson; 2 December 2022. https://pemedianetwork.com/petroleum-economist/articles/trading-markets/2022/outlook-2023-eu-diesel-demand-begins-to-shift-away-from-russia/
[52] Supply and Delivery of Gas Turbine Fuel Boiler Ignition Fuel and Black Start Diesel Fuel – 2024-97239 JW-Rev3, Specifications Page 1, SP 2 Quantities (page 111 of 118).
[53] Hydro corporate and operating assumption.

Logistics - Delivery requirements outlined in this section could prove to be a further deterrent for off-island suppliers, specifically when looking at the requirement during an emergency to deliver product to the Owner's fuel storage facility within 4 hours of receiving a request for product 24-hours a day year-round with an overall ability to deliver 400,000 liters per day (24 hours) to site if required. These requirements would be difficult for a supplier to meet without terminal facilities on the island. A change of Delivery Point / Incoterms to a port (i.e. St. John's, Come by Chance, Holyrood terminal[54]) is likely to make this RFQ more attractive to off-island suppliers. See Figure 33 for Point of Delivery and Transfer of Risk summary.

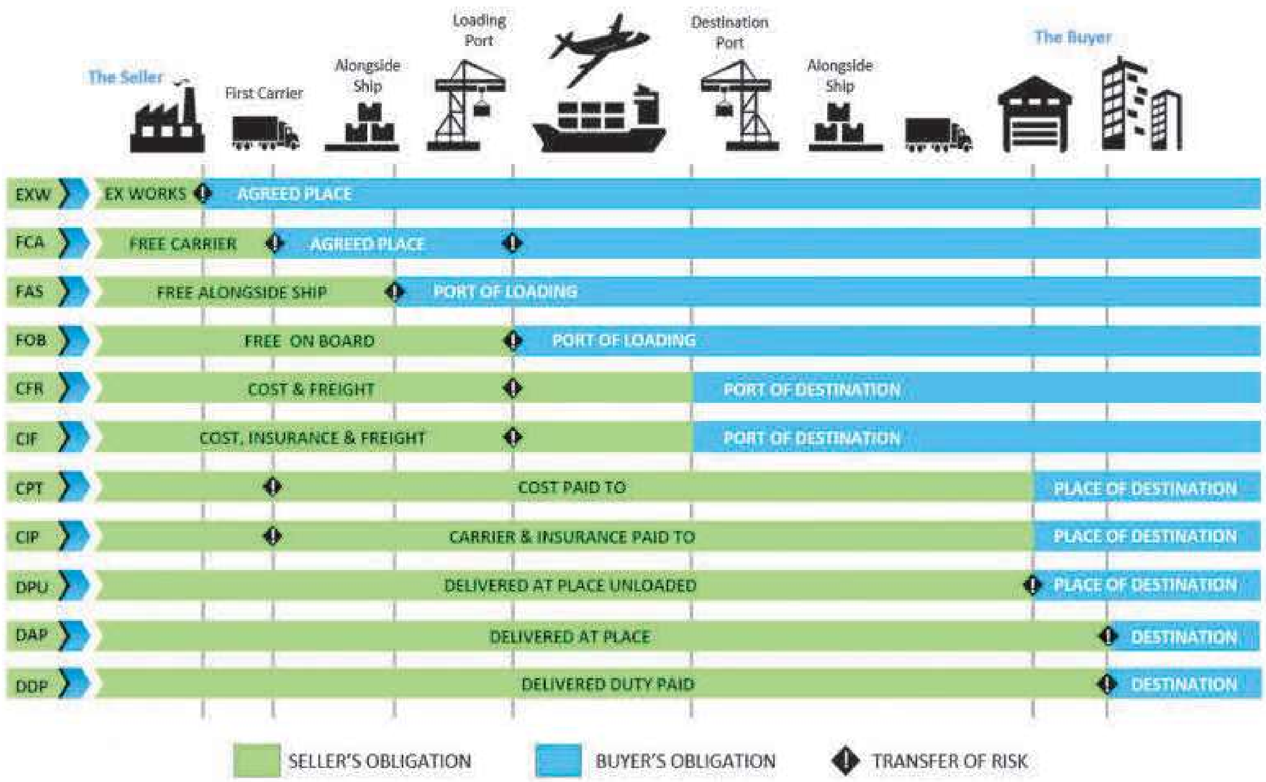


Figure 33 Incoterms 2020 – Point of Delivery and Transfer of Risk[55]

Incoterms are not specifically identified in the contract provided, but the Scope of Work[56] defines delivery points as Hardwoods Gas Turbine Plant (St. John's), Holyrood Generating Station (Holyrood), and the Stephenville Gas Turbine Plant (Stephenville) with the contractor being responsible for providing all materials and equipment used for transfer of the Product to Owner's storage facilities. This definition

[54] Retrofitted Bulk-C terminal at Holyrood power center or that of Valero Energy 10km's down the road.
[55] Incoterms 2020 – Point of Delivery and Transfer of Risk https://vivaxpresslogistics.com/incoterms/
[56] Supply and Delivery of Gas Turbine Fuel Boiler Ignition Fuel and Black Start Diesel Fuel – 2024-97239 JW-Rev3, Specifications Page 1, SP 1 Scope of Work (page 111 of 118)

roughly translates to Incoterms DPU specifically; DPU is the only Incoterm which explicitly tasks the seller with unloading.

Another consideration when looking to expand the off-island supplier pool is import duties, taxes, Provincial or Municipal licenses and fees as these are identified as the Seller's responsibility in the Specifications[57]. In a scenario where an off-island supplier is selected, delivered duty paid (DDP; Port) may be the better Incoterm.

Moving forward, the contracting strategy will need to evolve as the market conditions and Hydro's needs change. Fuel volume changes tied to future development will impact off-island supplier interest as larger volumes become more economically viable to ship, and the supplier pool will shift as we move towards 2050, with companies shifting infrastructure away from diesel to green(er) fuels to meet consumer demand and regulatory requirement. After an Expression of Interest (EOI) is completed and obstacles to supplier bids are clearly identified, the strategy can be refined for the next procurement cycle. For example:

- **Full Inventory Strategy**: here enough fuel is brought in before winter to support generation for 6 weeks. This requires investment in storage facilities, the initial cost of the inventory fuel, and an inventory management strategy for unused fuel such as burning off expired fuel, and offsetting the cost with electricity generation, or returning fuel to the supplier while it's still saleable and replenishing supply in turn. This model could be more difficult to scale with increased volume should more generation units come online.

- **Partial Inventory Strategy / Just in Time**: here enough fuel is stored to carry the utility for a predetermined time allowing for additional fuel supply to be purchased and delivered to Holyrood (I.e. 3 weeks supply). This requires lower infrastructure investment, and lower fuel investment along with a smaller inventory to manage. It additionally meets reliability requirements set out by the NL System Operator and gives the utility time to assess the outage situation and order fuel required ad-hoc; is easier to scale with more generation units coming online.

- **Supply Partnership / Just in Time**: more of an access model, this could involve one of the following: (i) leasing out new larger storage tanks at Holyrood where inventory is managed by an on-island supplier, (ii) new storage facilities built by the supplier close to Holyrood, or (iii) a contract built around a guaranteed access to fuel at existing facilities which can be readily delivered to site. In all cases, the fuel is cycled by the supplier distributing to their other customers but always ensuring ready access to a fresh fuel with Hydro not needing to concern itself with fuel quality management or the need to burn fuel outside of emergencies / peak demand. This approach may require the upfront purchase of fuel with storage fees[58], or an access fee structure. This strategy will become more difficult for on-island suppliers as demand for diesel declines and they do not have the need to keep larger quantities of fuel on-hand [59]. Off-island suppliers will become vital in this example.

[57] Supply and Delivery of Gas Turbine Fuel Boiler Ignition Fuel and Black Start Diesel Fuel – 2024-97239 JW-Rev3, Specifications Page 4, SP 4 Selling Price and Adjustment (page 114 of 118)
[58] Fuel Storage Agreements: Key Commercial Issues (US) https://www.mayerbrown.com/-/media/files/perspectives-events/publications/2022/01/fuel-storage-agreements-key-commercial-issues-w0336898.pdf
[59] Will Electric vehicles kill off gas stations? Fuel companies prepare for an uncertain future https://www.cbc.ca/news/business/gas-station-future-electric-vehicles-1.6434982

5.3 ASSET UTILIZATION: LIMITATIONS AND OPPORTUNITIES – TRANSPORT, STORAGE, OTHER AS APPLICABLE

The Holyrood site as far as GTs are concerned - the existing 123MW and the proposed 150 MW (3x50MW) turbines are emergency and peaking plants and by design currently and in the future (in theory) are not intended to be highly utilized Table 34. Row-2 clearly demonstrates that historically for most of the year, the power plant has not generated electricity and by implication the accompanying assets, the truck unloading area and four tanks were not 'actively' utilized in the classical sense.

No	Description	Units	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Operating Hours	hours	788	1,811	1,228	1,038	178	93	413	31	309
2	**Operating Days**	**days**	**33**	**75**	**51**	**43**	**7**	**4**	**17**	**1**	**13**
3	Percentage Utilization	%	9.0%	20.7%	14.0%	11.9%	2.0%	1.1%	4.7%	0.4%	3.5%
4	Fuel consumed	liters	13,276,144	26,358,691	24,954,656	21,233,897	4,084,699	1,978,072	8,948,316	689,476	6,138,125
5		barrels	83,505	165,791	156,960	133,557	25,692	12,442	56,283	4,337	38,608
6		tonnes	15,619	31,010	29,358	24,981	4,806	2,327	10,527	811	7,221
7	Deliveries - no. of truck loads	no.	214	425	402	342	66	32	144	11	99
8	Deliveries - no. of truck loads per 24 hours	no.	7	6	8	8	9	8	8	9	8

Reference(s)
NL Hydro data. See File of name 'HRDGT Operating Hrs and Fuel consumption'
(a) Hatch report, 28th September 2023, PDF Page numbers 79.

Barrels (liters)	*158.99*
Diesel No. 2	*0.85*
Factor	*1000.00*
Operating hours / annum	*8,760*
Fuel delivery (B-Train truck; liters)	*62,000*

Table 34 Holyrood Gas Turbines: Asset Utilization

The contradictory need of the situation – the expectation of instantaneous power in an emergency power outage or as a peaking unit, with sustained full-load operation for one or more days, and up to 6 consecutive weeks (42 days) with limited onsite storage of fuel compounds the situation. Circumstances are further exacerbated by the need to receive fuel by the only means possible - B-Train tanker trucks - and in particular their availability.

The Holyrood marine facility is currently used for heavy fuel oil (Bunker C) shipments for the Holyrood thermal generation facility, and the associated tank farm located approximately 850 metres from the Jetty. Four tanks with a capacity between 216,117 and 216,508 barrels (865,104 bbls total), coupled with port access via the Holyrood marine facility, should be factored into future expansion or overhaul plans for generation by gas turbine units.

On-Island Supply, if examined as an asset, carries risk when it comes to access. In an emergency scenario where non-contracted on-island fuel is to be leveraged to continue operations at Holyrood, the immediate risk is not knowing the level of supply available. A study should be completed to define readily accessible on-island fuel supply as well as any legislative requirements to commandeer / access this fuel supply. Secondary, how will this fuel be transported to Holyrood? Trucking availability may be limited by the number of trucks available, road access in the case of severe weather, availability of qualified operators, and/or the ability to offload fuel at the Holyrood site.

Asset Limitations

One of the largest challenges to the backup strategy for Holyrood is storage, followed closely by the carrying cost related to storing large quantities of diesel long-term as well as transportation constraints. Assuming a diesel requirement of 90,329,707 liters; Table 33 page 72, shows that to allow power generation for 6 consecutive weeks, the carrying cost of full tanks over an extended period is likely prohibitive; Table 35.

Smaller tanks holding a portion of the requirement and allowing time for more fuel to be shipped would have less upfront investment and opens the possibility of leasing tanks from or partnering with refiners, strategic reserves via terminals, or area businesses.

No	Example Price	Inventory volume (litres)	Purchase Cost	# Truckloads (B-train, 62,000L)	Remarks
1	$1.2820	40,698,000	$52,174,836.00	656	Contract reference price Jan 11, 2024
2	$1.2820	90,329,707	$115,802,684.37	1457	Contract reference price Jan 11, 2024
3	$1.6025	40,698,000	$65,218,545.00	656	25% increase on Contract reference price
4	$1.6025	90,329,707	$144,753,355.47	1457	
5	$1.7307	40,698,000	$70,436,028.60	656	35% increase on Contract reference price
6	$1.7307	90,329,707	$156,333,623.90	1457	
7	$2.0512	40,698,000	$83,479,737.60	656	60% increase on Contract reference price
8	$2.0512	90,329,707	$185,284,295.00	1457	

Reference(s)
Supply and Delivery of Gas Turbine Fuel Boiler Ignition Fuel and Black Start Diesel Fuel – 2024-97239 JW-Rev3, Specifications Page 4, SP 4 Selling Price and Adjustment (page 114 of 118)
Table 33 Holyrood: Asset Utilization, Fuel Consumed, 2016

Table 35 Fuel Diesel Investment Costs

The provided consumption figures for diesel (Table 2 page 7) identifies on-island trucking as an existing and constraint to additional power generating capacity being added at Holyrood. This will be true for any fuel. The Canadian Trucking Alliance (CTA) reported in 2023 that 34% of surveyed transportation companies were forced to turn away business due to labor shortages; 16% had postponed taking on contracts[60] and in 2024 that the situation would worsen due to the 35% reduction of international student permits[61].

While the above may not be the exact situation in Newfoundland at present, it highlights an issue impacting North America and supply chains reliant on road transportation; these or similar impacts (direct

[60] CFIB: Transport Firms Lost Nearly $2B in Business Due to Labour Shortage; December 2023. https://cantruck.ca/cfib-transport-firms-lost-nearly-2b-in-business-due-to-labour-shortage/

[61] International Student Cap Will Effect New Driver Recruitment: TN.com; February 2024. https://cantruck.ca/international-student-cap-will-effect-new-driver-recruitment-tn-com/

/ indirect) may need to be taken into consideration in Hydro's approach to contracting for supply and inventory management.

5.4 INVENTORY MANAGEMENT – MAXIMUM STORAGE CAPACITY

Aspects directedly and indirectly relevant to inventory management are discussed below:

- Current storage available on island,
- Proposed storage infrastructure on island,
- Sell excess power,
- Long term storage implications,
- Inventory cost, and
- Preservatives.

Regarding inventory, we again differentiate between on-island, off-island, contracted, and non-contracted. There is overlap, but methods to utilize these categories should be established and ready for mobilization in the event of requiring backup generation by the turbines at Holyrood.

Stantec was informed there is currently no documented inventory management process at Hydro[62] for Holyrood diesel, the reason being that inventory is used within a calendar year before stability becomes a concern. With a change in operating philosophy (emergency / peaker only) however, long term storage at Holyrood is becoming more of a concern. Hydro is planning further study and analysis on fuel management as part of their 2024 reliability plan.[62]

Looking at on-island inventory in the event of demand spikes, infrastructure failure, or reduced generation availability we need to quantify the available fuel to define requirements of subsequent fuel imports to support the backup/peak generation. What authority might the utility exercise to commandeer or prioritize diesel access on-island in the event of infrastructure failure under both federal and provincial emergency acts, and is on-island, non-contracted inventory adequate to carry Hydro through the first weeks of an emergency?

Another strategy would be to partner with on-island suppliers to have supplier-managed tanks in proximity to Holyrood allowing access via pipeline or short-haul trucking. The option reduces the need to hold high volumes of Hydro-owned inventory reducing the initial investment cost. This strategy also removes the inventory management component of dealing with millions of liters of fuel over the long term while having access to adequate supply if needed and addresses the potential trucking bottleneck.

5.5 SUPPLY CHAIN ALTERNATIVES – PRICING IMPACTS, OTHER AS APPLICABLE

Off-island access agreements could provide an opportunity to reduce infrastructure investment costs. Here, a robust supplier pool expanded to include terminals along the eastern seaboard (Canada, US) or even overseas is key. Having a strategic reserve available on short notice without the upfront cost of purchasing and storing the fuel removes the need to build tanks for the entire inventory, but capacity to

[62] As per personal communication with Hydro Operations Personnel, Follow-up question 1, March 8, 2024.

accept the deliveries at port would have to be managed. Shipments would temporarily strain local trucking capacity unless the jetty and tanks at Holyrood are updated to accept diesel shipments. Off-island supply contracts without having the storage available (owner / partnership) to receive shipments will complicate purchase agreements.

Merchant terminals can fill the role of non-contracted supply through ad-hoc purchases when required, possibly removing the requirement for a contract altogether. This should be investigated further using an EOI to survey the market more thoroughly as the volume of fuel needed may limit the supplier pool and fuel cost will have to be monitored. As prices rise, non-contracted purchases may become less feasible and should be measured against the costs associated with carrying inventory long term to determine affordability.

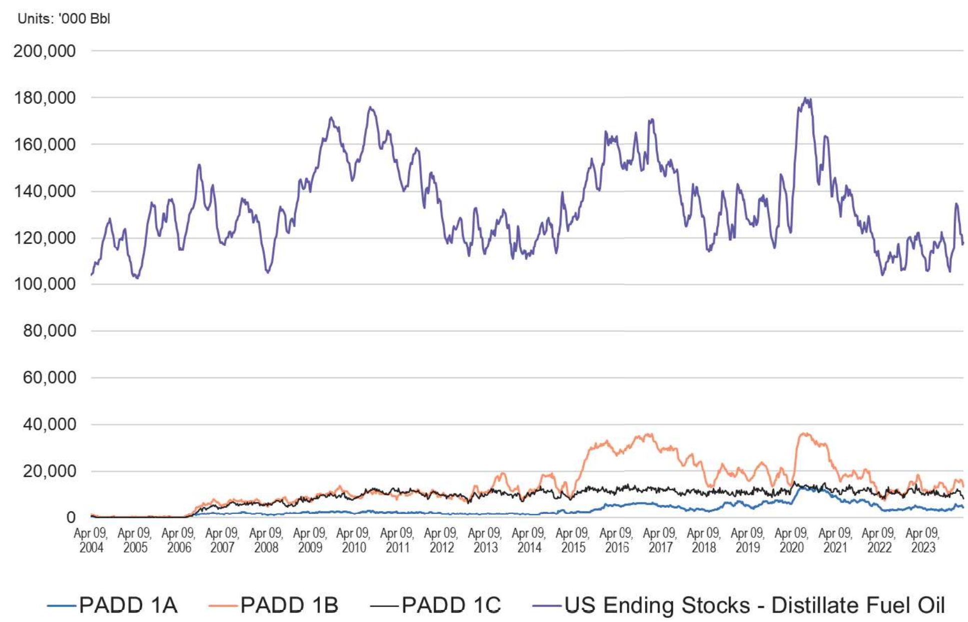
Alternative fuels in the context of being a supply chain alternative, are discussed in Section 7.

5.6 ASSESSMENT OF DECLINING AVAILABILITY OF NO. 2 DIESEL IN THE REGIONAL AND LOCAL MARKET

The following comments to considerations more short-term (month / quarter / few years) in character. These are not deep industry altering structural events per se. The reader is referred to Section 4 for commentary to the structural factors underpinning diesel production and supply from a historical and future perspective in Canada and the US.

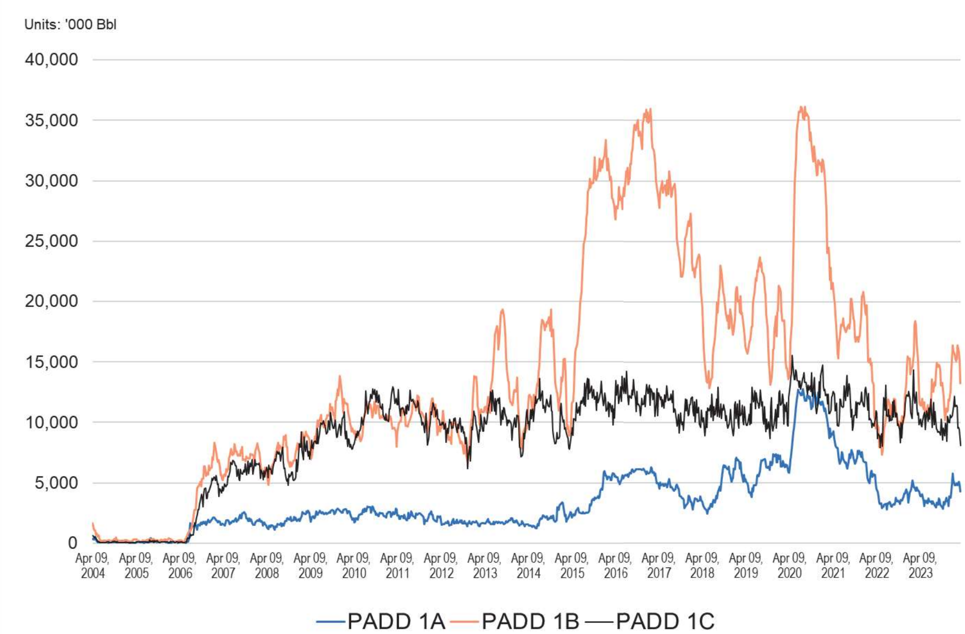
Starting at the refinery then down the supply chain, the section considers the movement of diesel in the regional and local market.

US ending stocks for middle distillate fuel are shown in Figure 34 and Figure 35 in total and then specifically for the three PADDS closest to Canada respectively along with US refiner net production of the same in Figure 36.



Reference: US Energy Information Administration;
http://www.eia.gov/oil_gas/petroleum/data_publications/weekly_petroleum_status_report/wpsr.html

Figure 34 US Ending Stocks Distillate Fuel – All, PADD 1A, 1B, 1C



Reference: US Energy Information Administration;
http://www.eia.gov/oil_gas/petroleum/data_publications/weekly_petroleum_status_report/wpsr.html

Figure 35 US Ending Stocks Distillate Fuel – PADD 1A, 1B, 1C

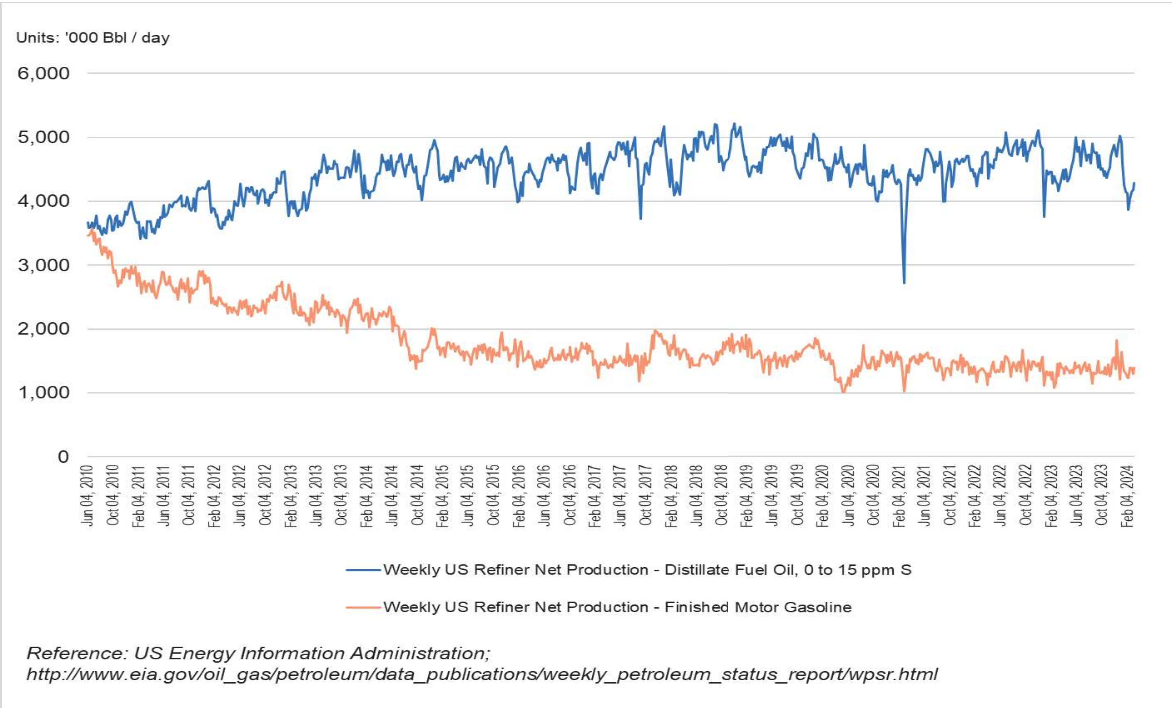


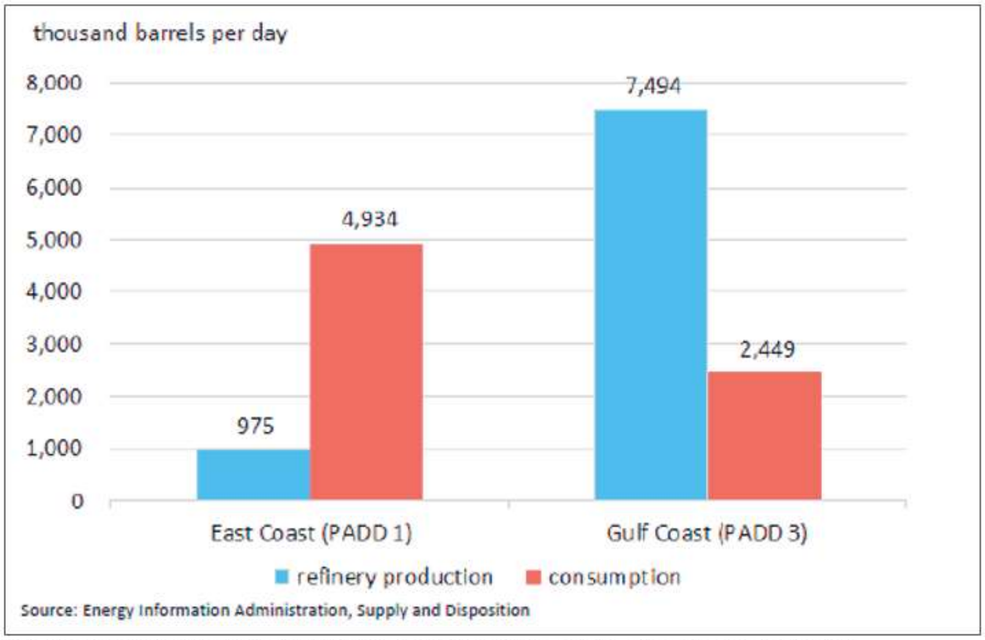
Figure 36 US Refiner Net Production; Distillate (0-15 ppm S), Finished Gasoline

Competing Regional Demand

The following provides a graphical overview of fuel production and supply dynamics in those US PADDs closest to Canada along with the latter's role in helping meet demand from these PADDs with Canadian exports (Figure 39 Callout 1).

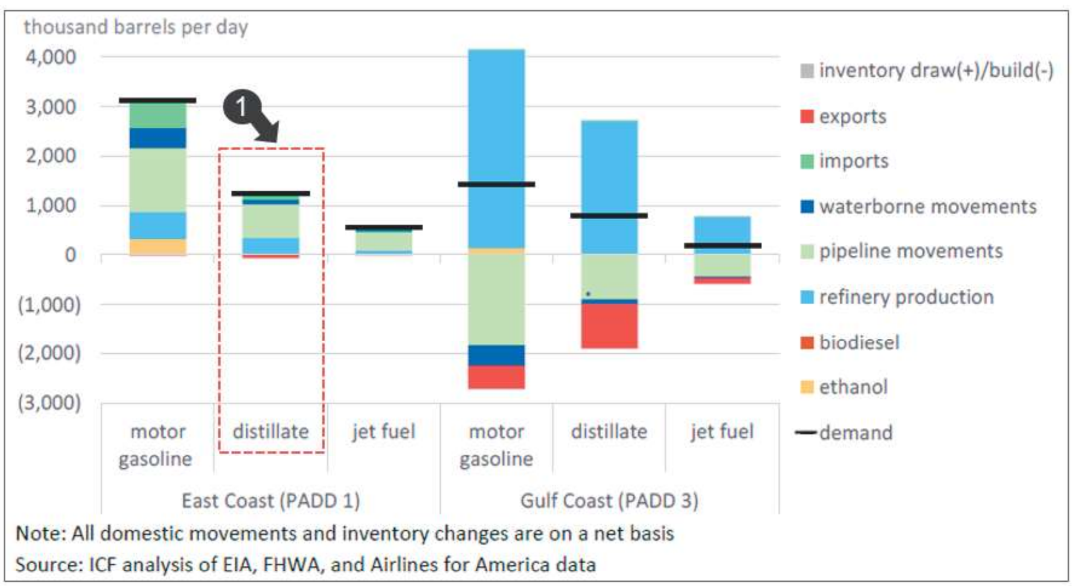
PADD-1 on the US east coast has a production deficit and is not able to meet the regions consumption need. Product is imported via domestic pipeline and waterborne supply from the USGC into the east coast ports, and at times from PADD-2 (Midwest)[63]; Figure 37 to Figure 40.

[63] East Coast and Gulf Coast Transportation Fuels Markets - A report prepared by ICF International for EIA; Feb. 2016. PDF page no. 17.
https://www.eia.gov/analysis/transportationfuels/padd1n3/pdf/transportation_fuels_padd1n3.pdf



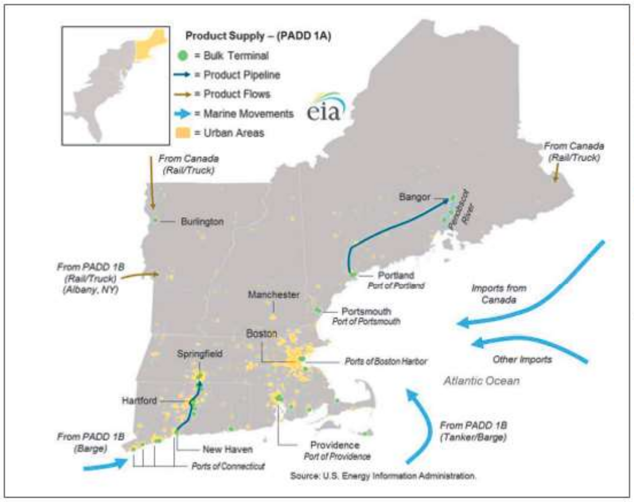
Reference: East Coast and Gulf Coast Transportation Fuels Markets - A report prepared by ICF International for EIA; Feb. 2016. PDF page no. 11.
https://www.eia.gov/analysis/transportationfuels/padd1n3/pdf/transportation_fuels_padd1n3.pdf

Figure 37 Refinery production versus consumption (PADD-1 and PADD-2)



Reference: East Coast and Gulf Coast Transportation Fuels Markets - A report prepared by ICF International for EIA; Feb. 2016.
https://www.eia.gov/analysis/transportationfuels/padd1n3/pdf/transportation_fuels_padd1n3.pdf

Figure 38 Domestic Movements – PADD-1 and PADD-2 *(a) US New England refined petroleum infrastructure*



(b) Waterborne receipts of transportation fuels at New England ports, 2013

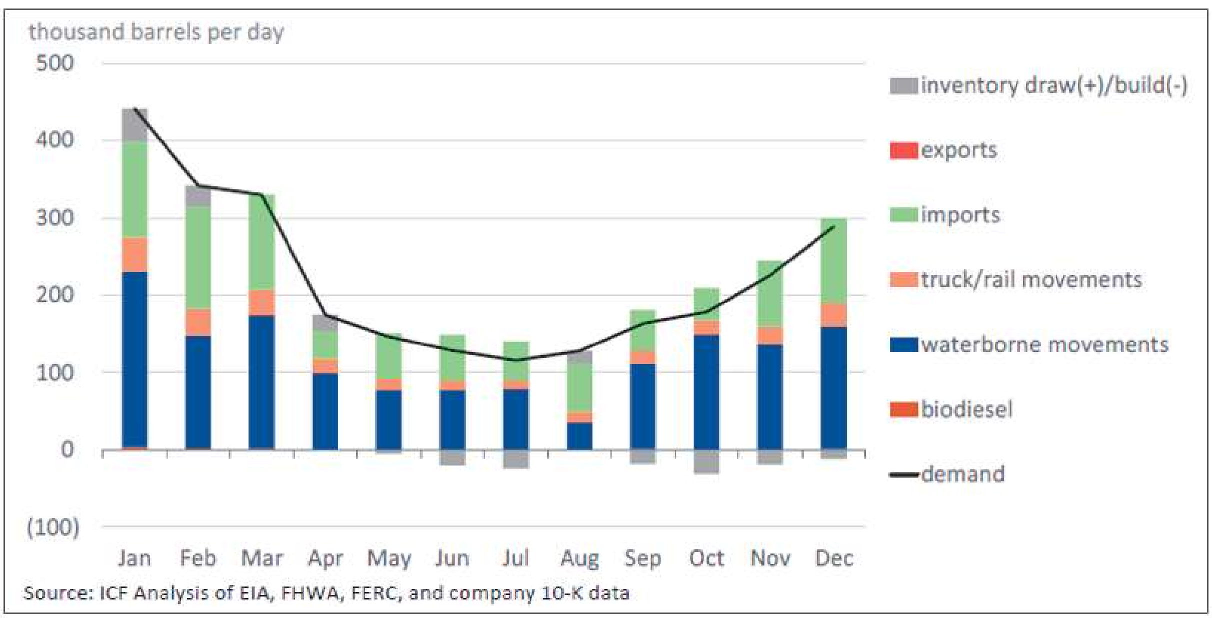
barrels per day

Port	Domestic	Foreign	Total	Canadian % of foreign
Boston, MA	83,166	110,304	193,470	61%
New Haven, CT	95,217	50,868	146,085	46%
Providence, RI	40,100	64,356	104,456	34%
Portland, ME	10,865	54,608	65,473	94%
Portsmouth, NH	7,041	8,501	15,542	100%
Penobscot River, ME[B]	1,493	7,438	8,931	100%
Other, CT[C]	22,907	0	22,907	0%
Other, MA[C]	2,489	0	2,489	0%
Total	**263,278**	**296,077**	**559,353**	**60%**

(A) Includes Searsport, Belfast, and Bucksport, Maine
(B) Includes Bridgeport, New London, and Stamford, Connecticut
(C) Includes Fall River, New Bedford, Nantucket, and Martha's Vineyard, Massachusetts
Source: U.S. Army Corp of Engineers 2013 Waterborne Commerce of the United States Waterways and Harbors; EIA Company Level Imports, 2013

Reference: East Coast and Gulf Coast Transportation Fuels Markets - A report prepared by ICF International for EIA; Feb. 2016. PDF page no. 40 and 41. https://www.eia.gov/analysis/transportationfuels/padd1n3/pdf/transportation_fuels_padd1n3.pdf

Figure 39 US East Coast Ports: PADD-1



Reference: East Coast and Gulf Coast Transportation Fuels Markets - A report prepared by ICF International for EIA; Feb. 2016. PDF page no. 37. https://www.eia.gov/analysis/transportationfuels/padd1n3/pdf/transportation_fuels_padd1n3.pdf

Figure 40 US East Coast Fuel Market Dynamics

While the diesel market is shifting and will shift further to varying degrees in the decades ahead in response to electrification, it is unlikely to disappear in the short to medium term for the expedient fact that both government and society will demand back-up power. In short, #2 diesel fuel will continue to be available, but premium pricing is foreseen as possible risk to Hydro in the medium to long-term as function of a shift in oil refining to chemicals as refiners respond to increased pressure to move away from producing fossil-based transportation fuels.

5.7 RISK REVIEW

A desk-top risk review of the Holyrood gas turbines in the context of the present 123MW GT and future 150MW GT was conducted from the perspective of two risk categories:

- (a) inbound: risk factors direct and indirect affecting the delivery of diesel and transmission of electrical power to the island, and
- (b) outbound: risks affecting the production and delivery (emergency / peak) of power at and from Holyrood respectively.

Description of identified risks prior to mitigation is provided in Table 6 and depicted respectively for the inbound and outbound risk in Figure 41 and Figure 42 respectively.

(a) Inbound Risk Factors

No	Risks / Events	Risk Description	Remarks
1	Labrador Island Link (LIL)	Transmission line damaged, e.g. tower.	Outage expected - 6 wks.
2	Ice storm	Muskrat Falls to shore.	Outage expected - 6 wks.
3		Shore to terminals (on-island).	Outage expected - 6 wks.
4	Canada Regulation / energy transition	Canadian refiners come under increasing pressure, reduce production, some refineries close.	10 years or longer.
5	Canada's Electric Vehicle Availability Standard (EVAS)	Auto producers / importers must meet annual ZEV sales targets beginning 2026 (20% of new LDVs offered as ZEVs); increasing annually by 60% reaching 100% for 2035.	Gasoline demand declines after 2035, falls further post 2045 (average LDV life). Refiners cut back on diesel, some close.
6	US Regulation / energy transition	Carbon tax is progressively implemented, diesel production stagnates.	20 years or longer.
7	Diesel supply interruption - to island	Diesel not available.	Refiner / terminal supplier has low / no inventory.
8		Barge / ship not available.	Engine problems or similar.
9	Diesel supply interruption - on island	Primary road blocked - snow.	Seasonal
10		Primary road blocked - B-Train incident.	Not season dependent.
11		Primary road blocked - Car incident or similar.	Not season dependent.
12	EVs on Newfoundland	Progressive increase in on-island EV reduces diesel demand.	Less diesel imported and available in storage. No. of interested suppliers declines.
13	Over-all Contracting Strategy	No. of suppliers bidding on contracts reduces further	risk of no. of on-island bidder interest declining, contracting strategy is not attracting off-island bidders
14	Suppliers	Current number of logistics companies active in transporting fuels.	No. of able / willing suppliers decreases.
15	Suppliers	E.g. Woodwards is privately owned - will [future] owners continue operating?	No. of able / willing suppliers decreases.
16	Trucks	Availability of an adequate no. of B-Trains such that the terms of contract can be met.	Indication is that truck deliveries to the Holyrood 123MW GT is already challenging under some circumstances.
17		Is there an adequate no. of qualified drivers able to perform delivery per contract?	

(b) Outbound Risk Factors

No	Risks / Events	Risk Description	Remarks
1	Ice storm	Power / towers lines from Holyrood damaged.	Outage expected - 2 to 3 wks.
2	Hurricane	Widespread transmission damage and road closures	Outage expected - days to 4 weeks
3	Diesel quality	GT unable to startup due to filter blockage.	Diesel has approached storage limit date.
4	Diesel quality	GT shuts down due to filter blockage.	Diesel has approached storage limit date.
5	Inventory	GT cannot start / shuts down because site runs out of diesel.	-
6	Inventory	GT has to cut back on load due to insufficient inventory on hand.	-
7	Grid reliability	Diesel consumption / storage - improvement in NL grid reliability decreases the utilization at Holyrood GT.	Diesel needs to be stored longer - stability concerns.
8	Fuel stability	Long-term stored fuel degrades Storing 6 weeks of fuel requires initial investment and inventory management strategy	GT cannot start. Off-spec fuel needs to be sold at discount. GT in-operable as disposal solution is found.

Table 36 Risk Matrix: Inbound and Outbound Risk Factors

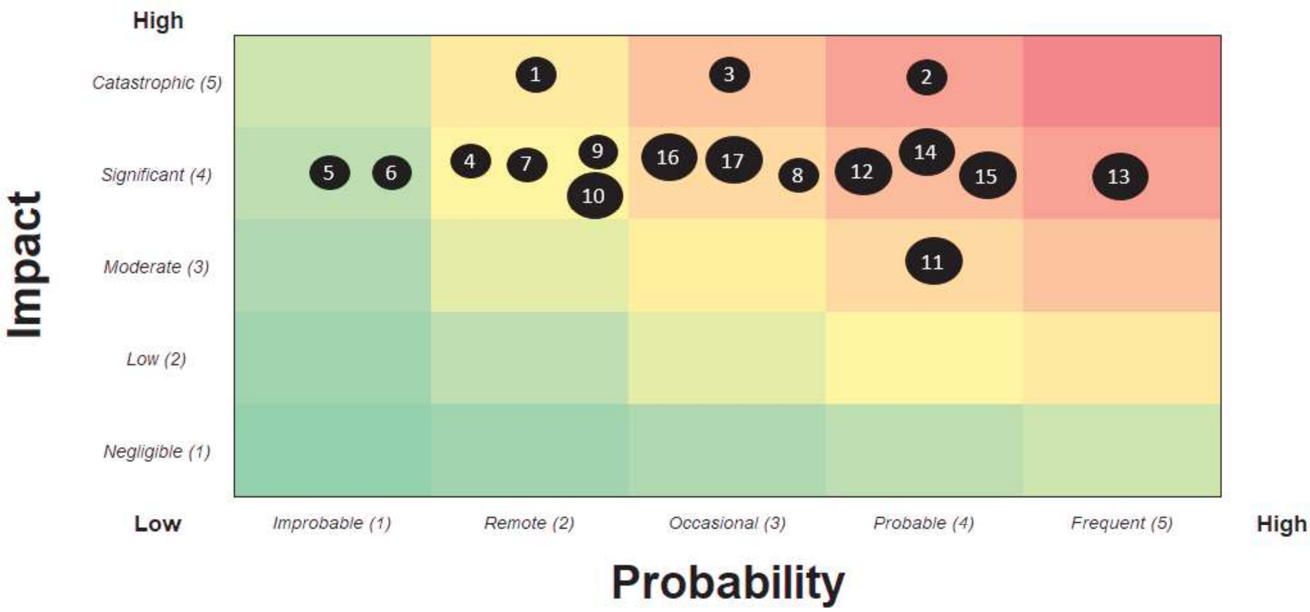


Figure 41 Risk Profile: Inbound Risk Factors

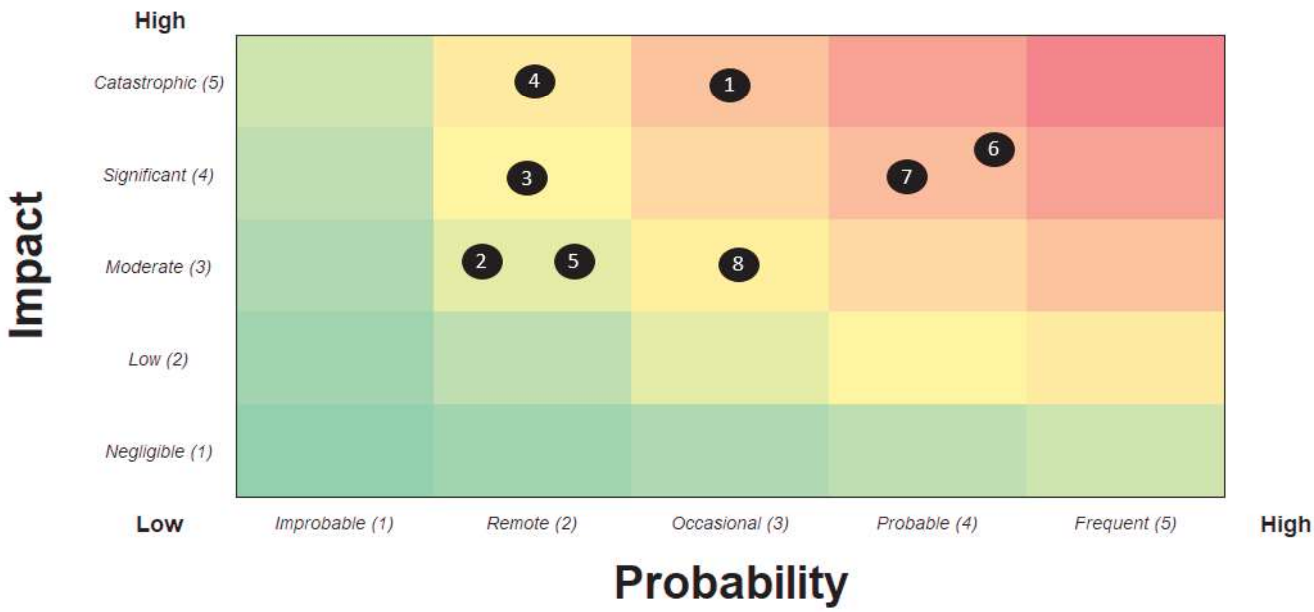


Figure 42 Risk Profile: Outbound Risk Factors

5.8 SUMMARY AND RECOMMENDATION

With traditional diesel supply potentially restricted due to overall decline in demand, refinery closures or conversions, and transportation and heating markets trending towards electrification, Hydro's future contracting strategy is crucial to securing the supply of diesel when planning a supply for emergency situations where time is of the essence. In short, diesel will be available, but it will likely be at a premium price if the market moves to "niche" markets due to governmental push to shift away from fossil fuels.

Whilst the contracting strategy must reflect a competitive diesel price, consideration must be given to expanding the present supplier pool along with possible incentives targeting the supplier. This could include opportunities for value-add, partnerships, infrastructure opportunities, or infrastructure investment.

Identifying potential suppliers and issuing an Expression of Interest before the next procurement cycle would allow for intelligence gathering in the market. This tool would help identify barriers suppliers see when considering bidding on an open RFP. Erratic demand, on-island transportation limitations, port capacity, contracted delivery points, or shipping costs are likely culprits, awareness of the RFP may also be playing a part in low response rates. Identifying potential bidders outside of traditional refiners will be a key component to the EOI exercise; this could be done proactively.

Upon identifying supplier concerns, the overall contracting strategy will need to be examined to attract new bidders. Strategic incentives such as performance bonuses or changing the negotiated delivery point might be enough to increase bid response. Any strategy landed on, should be reviewed regularly to ensure the strategy matches prevailing market conditions as government climate initiatives are implemented in Canada and globally, and by so doing, maintain a healthy pool of suppliers.

6 PART 3: CRITICAL ASSETS TO THE TOTAL SUPPLY CHAIN (FROM FUEL PRODUCER TO HYDRO)

The following considers:

- Section 6.1: Climate Driven Disruptions,
- Section 6.2: Refinery Conversions / Redundancy / Closures,
- Section 6.3: Regulation: Current and Future,
- Section 6.4: Turbine Technology, and
- Section 6.5: General: Demand Volatility, Economy

A high-level overview and commentary of risks to the total supply chain from refiners and across TS&D is provided in the following. The reader is also referred to Section 5.7 for a discussion on the desk-top risk review.

6.1 CLIMATE DRIVEN DISRUPTIONS: FROM FEEDSTOCK AVAILABILITY TO IMPACTS ON DELIVERED FUEL PRICE

Crude oil - the refining thereof and the production of fuels - is a global activity. Figure 46 page 93 is provided to demonstrate the extent to which crude oil is shipped globally.

As they have done in the past, climate events (routine weather patterns or those possibly related to climate change) can be expected to disrupt crude production and refinery operations. As industry has endured and recovered from such events in the past, so should the same be expected in the future.

The contracting and inventory strategy selected by Hydro will play into how sensitive the utilities supply chain is to climate disruptions. Just-in-time (JIT) models carry a small(er) inventory, but the bulk of Holyrood's inventory is always in transit, whereas an alternative – a decision to carry full or partial inventory would buffer against disruption. These risks are further tied to primary supplier location, and on-island suppliers in turn.

Hurricanes impact the southern US offshore oil and refining sectors regularly. In 2023, the forecast loss of refinery production for the region was approximately 1.5 million barrels per day[64]. The Atlantic hurricane season runs from June 1st through November 30th, the effects of a single hurricane can be felt from the Gulf all along the eastern seaboard through Atlantic Canada and Newfoundland, disrupting not only production, but fuel transportation along the coast.

---

[64] STEO Perspectives: How do hurricane-related outages affect gasoline production and prices - https://www.eia.gov/outlooks/steo/report/perspectives/2023/07-hurricanes/article.php#:~:text=Hurricanes%20can%20significantly%20disrupt%20U.S.%20offshore%20crude%20oil,a%20nearly%20equivalent%20temporary%20loss%20of%20refining%20capacity.

Transportation costs are forecast to continue to rise as already low distillate fuel inventories are tightened by improving industrial economies in US and Europe since COVID in 2020[65]. As we have seen historically, fuel prices will increase further with refinery shutdowns due to severe weather and specifically with hurricanes impacting the southern US.

6.2 REFINERY CONVERSIONS / REDUNDANCY / CLOSURES: AS FUNCTION OF THE ENERGY TRANSITION, SUPPLY VOLATILITY

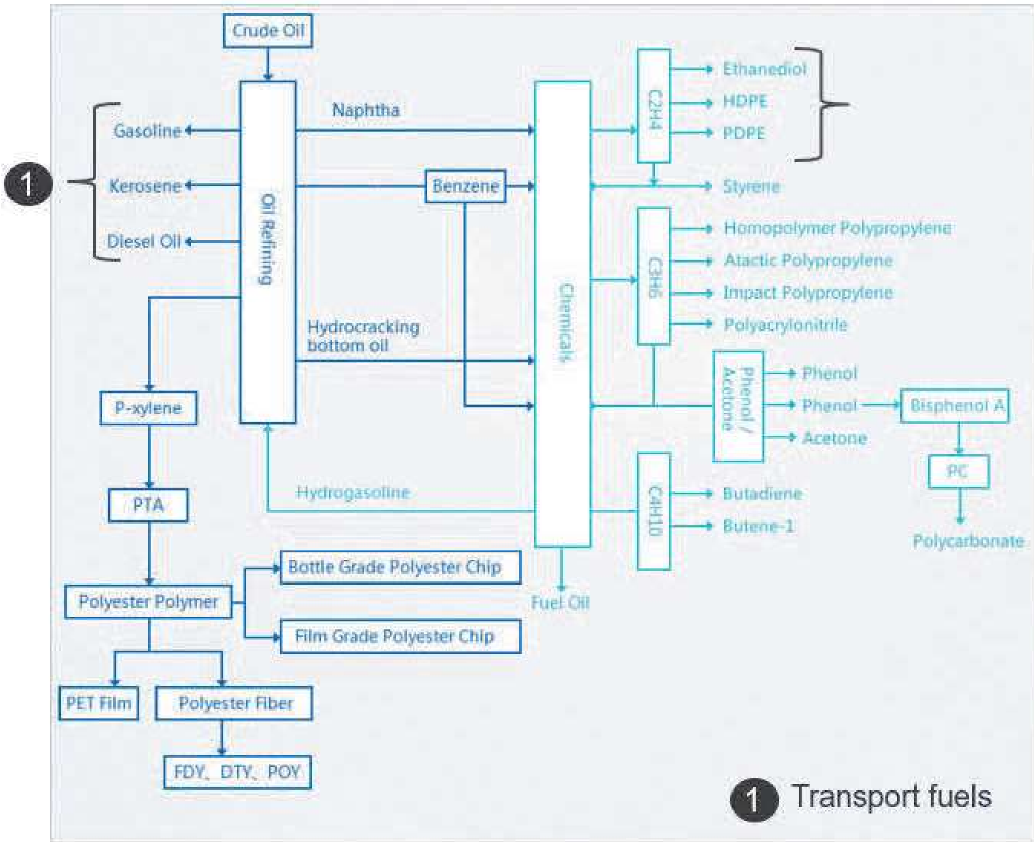
Since first constructed, refineries (refining technology) have never remained static. Soon after crude oil was discovered in Pennsylvania in 1856 and distilled for cleaner lighting fluid to replace sooty animal fats (candles) and whale oil (lamps), refineries evolved in fits and starts in response to internal (technology push) and external (market pull) opportunities mixed with crises and threats. Conflicts and the peace between, created a need and opportunity for advanced fuels and new materials. Modern aviation and the plastics industry both owe their beginnings to technology discoveries and advances of World War II.

Figure 44 and Figure 45 highlight pivotal moments in refining history since 1856. Rather than close, refineries have evolved and can be expected to continue doing so.

In the past decade or so, those refiners with the vision and resources have responded to not only climate change concerns, but also the emergence of EV's and the potential threat this poses to the traditional refining business model. Two examples are: SABIC[66] and Rongsheng Petrochemical. Figure 43 shows that Rongsheng still produce a fraction of transport fuels whilst they are primarily focused on the conversion of imported Saudi oil to chemical intermediates from which they produce polyester fibers. The two examples serve to illustrate that whilst a fuel type may be in short supply for a time – the base feedstocks and processes themselves do not disappear, and that refiners and or petro-chemical producers within reason, are able to choose which market they address.

---

[65] Diesel Prices Set to Surge in 2024 - https://oilprice.com/Energy/Gas-Prices/Diesel-Prices-Set-to-Surge-in-2024.html
[66] SABIC and Aramco plan to start crude-to-petrochemicals project in Ras Al-Khair; 24th November, 2022; Mohammad Alsulami. https://www.arabnews.com/node/2205306/business-economy



Reference: RongSheng Petrochemical; https://www.cnrspc.com/rscy

Figure 43 Rongsheng Petrochemical Production

- **1859**: American oil rush starts - Titusville, Penn. 1st well drilled by E. L. Drake. 1st products used for lighting.
- **1908**: Ford introduces Model-T to world & opens a new market other than lighting.
- **1912**: 1st thermal cracking is practiced.
- **1915**: 1st attempt of catalytic cracking with aluminum chloride made by McAfee-Gulf.
- **1928**: E. Houdry & Vacuum Oil Co. begin working together & develop an acid-activated clay catalyst.
- **1936**: Houdry process goes on-line with - 2,000bpd capacity.
- **1939**: Development of fluid bed concepts by Lewis – Exxon.
- **1940**: Exxon produces 1st synthetic silica alumina catalyst.
- **1942**: 1st commercial FCC unit built by M.W. Kellogg for Standard Oil of New Jersey's Baton Rouge, Louisiana refinery, commissioned May 1942.
- **1942 - 1944**: Kellogg builds 22 of 34 FCC units constructed throughout the U.S.A.

Reference(s): Stantec

Figure 44 (a) Technology Development in the Refining Sector

- **1954**: Union Carbide develops a synthesis for zeolites.
  - Zeolite catalysts differ from conventional crystalline materials because the anhydrous crystal has a regular structure of large pores. Zeolites offer greater selectivity.
- **1962**: Zeolites are introduced into the FCCU.
  - Historically FCC's used to crack "barrel bottoms" to increase white product (paraffin) yield & later to increase octane no. of gasoline whilst maintaining the yield from high-boiling feedstock.
- **1970's:** Mobil develops the Methanol-to-Gasoline (MTG) process.
- **1971**: Short contact risers are introduced.
- **1986**: ZSM-5 is introduced by Mobil.
- **2006**: Grace Davison is 1st to introduce Selective Active Matrix (SAM) systems.
  - FCC's traditionally been applied to the production of transportation fuels. Increased demand for propylene sees FCC's increasingly a tool to produce on-demand propylene.
- **2000's**: commercialization of shale gas.
- **2011**: 1st large scale Methanol-to-Olefins plant (MTO) built in China.
- **2000's**: 1st ethane cracker is built.

Reference(s): Stantec

Figure 45 (b) Technology Development in the Refining Sector

6.3 REGULATION: CURRENT AND FUTURE

For a more detailed discussion on regulations in Canada and US the reader is referred to Sections 4.4 page 44, and 4.5 page 56 respectively.

Regulations – current and future are generally implemented by provincial, federal governments and economic trade blocks (e.g. European Union) with a particular objective in mind. This can naturally take various forms – some might seek to improve or close an industry (e.g. asbestos mining).

Desulfurization of refinery products like bunker fuel and restriction of use in certain sea lanes / areas is not a new development. Diesel and gasoline were required to be desulphurized from around the early-2000's where this was directed to improving air quality and reducing acid rain. Restrictions on maritime bunker oil / fuel are a natural extension of this.

Restrictions on bunker fuel oils does not affect all refiners equally, the effect is tempered by numerous factors such as refinery location, refinery complexity, the character of the crude oil itself and the market the refinery owner services or is targeting.

Desulphurization of bunker fuels need not necessarily negatively impact the availability of diesel No.2. By example: from around 2000 to 2010 several automotive manufacturers of the likes of Volkswagen were advocating the positive attributes of diesel engines to the LDV market in competition to gasoline engines. The former required ultra-low sulphur diesel (ULSD), the implication being that desulphurization at that time in history was paving the way to a new market with expected increased growing demand for desulphurized diesel. It is on this basis that companies like BP, Chevron, ExxonMobil, Sasol and Shell were developing gas-to-liquids (Fischer-Tropsch) technology for commercial deployment. Except for the latter two companies, the remainder at least for the present, have halted their GTL ambitions.

6.4 TURBINE: CURRENT AND FUTURE OF POWER CONVERSION TECHNOLOGY

The proposed design basis for Holyrood in Hatch's September 2023 report under mechanical and fuel system stated that: 'the basis for the design of the simple cycle combustion turbine is that the turbines need to have the capability of running on diesel fuel with a possibility of converting to either natural gas, biodiesel, ethanol, or hydrogen in the future.'[67]

Molière (2023)[68] reviews the high flexibility of land-based gas turbines to different fuels. Fuels referenced - in essence alternatives to diesel - cover a range of hydrocarbons and blends not conventionally marketed as fuels; by example: aromatic rich streams, naphtha, refinery 'straight run' products, and residual oils.

---

[67] Hatch report, 28th September 2023, PDF page no. 23.
[68] Molière, M. The Fuel Flexibility of Gas Turbines: A Review and Retrospective Outlook. Energies 2023, 16, 3962. https://doi.org/ 10.3390/en16093962. Academic Editor: Andrea De Pascale. Received: 17 March 2023.

The author further comments to the importance gas turbines will play in the energy transition, speaking to the fact the transition will require back-up power systems when renewable power does go down. The implication of this is that society and government by necessity, will maintain an operating base of refineries (conventional and new) to cover such events.

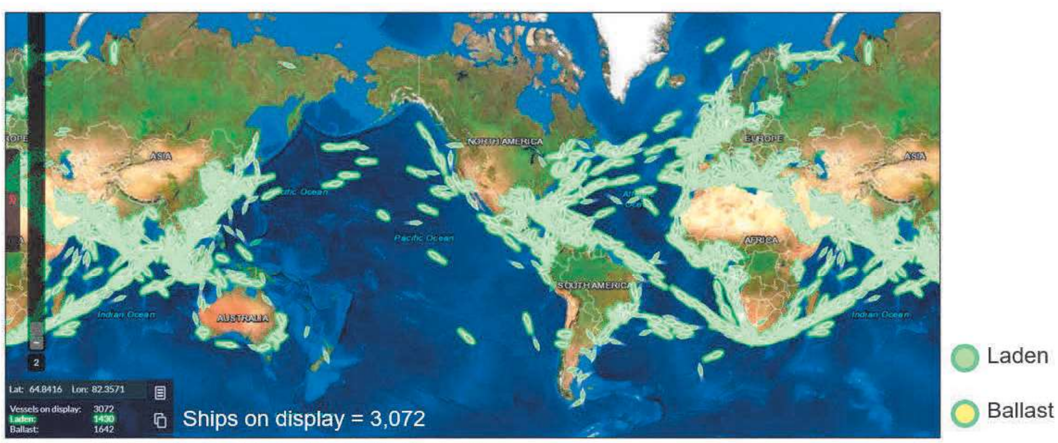
6.5 GENERAL: DEMAND VOLATILITY, ECONOMY / INFLATION, GEOPOLITICS, REGIONAL LABOUR RELATIONS

Geo-political events are not new (Ukraine war, Gaza / Israel, disruption on the Suez Canal; concerns on the Panama Canal) and by nature disrupt the global economy. Less well known is the scale at which commodities and products (intermediates and finished) of various description travel the world.

In the 1950's / 1980's products servicing daily lives were likely to have been produced a block, county or province over. This is less true today, crude oil and chemicals (Figure 46; Figure 47) are examples of a commodity and product traded at a global scale to the extent that when trade is disrupted by events, the impact is mitigated by the availability of alternatives and the very scale of the activity itself.

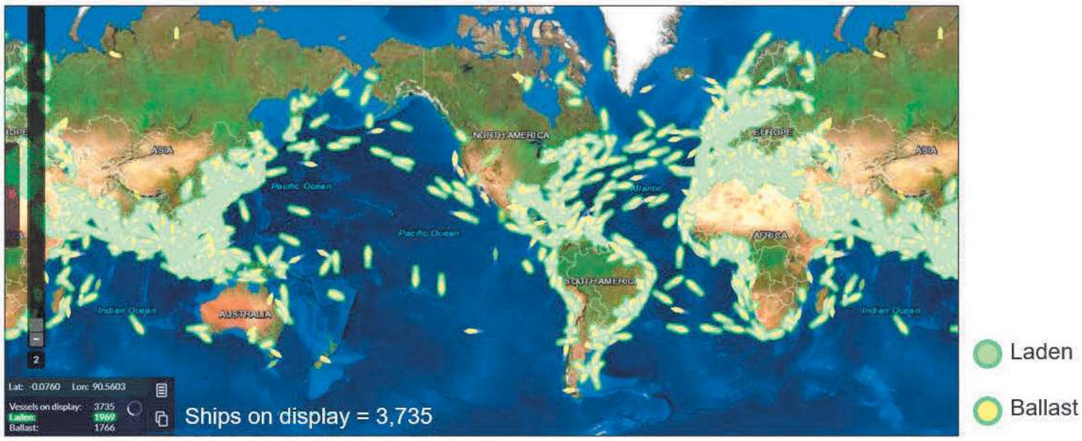
Demand volatility, state of the economy (interest rates, inflation) geopolitics, regional labor relations and other factors are for the most part, out of Hydro's abilities to influence. The remaining option is to acknowledge such events and from that, determine how they might be mitigated against.

Should supply of diesel to Holyrood be disrupted in or from mainland Canada or West Coast US, there are options. Supply from further afield (Europe, Africa, Japan) however, will require intentional planning and continued management.



Reference: OPIS Mint (subscription) – Crude oil tanker tracking

Figure 46 Global Crude Oil Tanker Shipping



Reference: OPIS Mint (subscription) – Chemical tanker tracking

Figure 47 Global Chemical Tanker Shipping

7 PART 4: PROVIDE OUTLOOK TO ALTERNATIVE FUEL SOURCES AND POTENTIAL TIMELINE

The following covers:

- Section 7.1: Introduction
- Section 7.2: Energy Density of Fuels,
- Section 7.3: Fuel Composition and Fuel Stability,
- Section 7.4: Alternative Fuels

7.1 INTRODUCTION

Alternative fuels evaluated in Hatch's September 2023[69] report were:

- Biofuel and ethanol
- Hydrogen (various blends) and
- Natural gas

By definition: an 'alternative fuel' can only be classified as an 'alternative' if the candidate fuel is able to meet the operational needs of the circumstances into which it is to be deployed - current and future. Consequently, some discussion on the chemical / physical properties and implications thereof, of a candidate fuel is warranted. This is done in advance of an overview of alternative fuels (Section 7.4) in Section 7.2: Energy Density of Select Fuels and Section 7.3: Fuel Composition and Fuel Stability.

With the above in mind, the following serves to provide a general overview as to what alternative fuels might be practical and appropriate for the Holyrood gas turbines. It will hopefully also demonstrate that should the availability of diesel come into question in the far future, that there is likely a workable alternative near at hand. Diesel after all is but one fuel type and hydrocarbons by definition are broader, and with innovation, therein lies the alternative.

7.2 ENERGY DENSITY OF SELECT FUELS

A key aspect when considering candidate fuels as 'alternative fuels' is their applicability or 'fit' to Newfoundland and Hydro's unique geographic and seasonal circumstances.

This is quickly evidenced when a comparison is made between the energy density of diesel relative to other fuel types; Table 37. For practical reasons diesel became a fuel of choice for distributed and stationary power generation and whilst diesel's density was not necessarily a criterium for being selected

[69] Newfoundland and Labrador Hydro - Concept Design Report Final Report; Hatch, 28 Sept. 2023. PDF Page number 74.

when first deployed, by the fact that it occupies the position it does today, energy density now becomes a consideration – a reference against which alternatives are judged.

Density impacts volume on three fronts: (i) the volume necessary in the engine in which it will be used; (ii) the volume necessary to transport and (iii) the volume necessary to store.

Ethanol by example has been used to power two General Electric (43.5MW; LM6000) GT's in Brazil[70] – the largest producer of ethanol. However, in the Newfoundland context, were ethanol to be considered a viable alternative fuel – logistics and storage are increased 1.6 times for the same generation output. Based on Hydro's current operational experience on the Holyrood GT (123MW), it becomes quickly obvious that ethanol exacerbates the logistics issue. It does however offer the following: it is close to 100% renewable (could still have some GHG emissions in the lifecycle such as for transportation to site if fossil fuels are used), production capacity is expected to grow in the future, it does not have the same stability issues of conventional diesel, biodiesel or renewable diesel, nor would it attract emission penalties.

Green-hydrogen whilst offering zero emissions is plagued by the same energy density illustrated for ethanol – but 4x so relative to diesel. Other challenges of H_2 are briefly referenced in the footnote[71].

No	Energy Content	Units	Diesel (LSD)	Biodiesel	Renewable Diesel	DME	Butanol[(a)]	Ethanol[(a)]	Methanol [(a), (b)]	LNG	FT Diesel[(b)]	Hydrogen (liquid)
1	Lower Heating Value (LHV)	Btu / gal	**128,488**	119,550	123,542	68,930	99,837	76,330	57,250	74,720	123,670	30,500
2	Higher Heating Value (HHV)	Btu / gal	138,490	127,960	133,070	75,655	108,458	84,530	65,200	84,820	130,030	36,020
3	Diesel Gallon Equivalent (DGE)	-	**1.00**	1.07	1.04	1.86	1.29	1.68	2.24	1.72	1.04	4.21

Reference(s)
California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/053017draft-qm-hydrotreater.xlsx

FT - Fischer-Tropsch *LNG - Liquified Natural Gas* *LSD - Low Sulphur Diesel*

Color has been used to highlight the differential from conventional diesel.

(a) Belong to a class of chemicals / fuels known as 'alcohols'.

(b) E-fuel (assumption)

Table 37 Comparison of Diesel with Other Fuel Types

70 GE powers turbines with ethanol in Brazil; 23rd September 2010. https://ethanolproducer.com/articles/7031/ge-powers-turbines-with-ethanol-in-brazil/

71 Energy density is just one factor hydrogen presents; other considerations are: (i) Liquid H_2 (LH2) storage temperature is minus 273ºC. The storage tank is complex, it must be spherical (to minimize contact with the hot outside world). It is also double walled with an insert of perlite (insulator) and encased in liquid nitrogen (minus 196ºC). (ii) there is a rule of thumb, with a loss of 1% of the total volume every day a boil off gas capture system is required, this has its own power need. LH2 is not to be used for long term storage; this is what ammonia is there to do.

7.3 FUEL COMPOSITION AND FUEL STABILITY

Diesel if not correctly managed during storage will chemically degrade[72] to varying degrees in the medium to long-term when exposed to air (oxidation), high temperature, sunlight, and water (via condensation or other). If appropriately managed with biocides, circulation / filtering to remove solids, and nitrogen blanketing along with routine inspection and cleaning of tanks, the stability of diesel can reportedly be extended beyond 12 months[73].

Conventional crude derived fuels are generally a complex mixture of components and by default are not simple products. For the most part, fuel components[74] and fuels that are distributed, traded and retailed at the gas bar or via other means, are exceedingly complex mixtures of hydrocarbons – not hundreds of separate [chemical] compounds, but thousands.

Fuels produced at different refineries of different technology vintage, technology configuration and from different grades of crude oil differ chemically. Where they do not differ however, is in terms of their macro- or gross chemical and physical properties such as aromatic / olefin content, density, octane (gasoline) / cetane (diesel) number, flash point and so forth on which fuels are produced, approved and sold to market.

Earlier generations of crude / petroleum derived diesel are known to be less susceptible to degradation than those currently produced due to their then higher sulphur content. Susceptibility towards bio-degradation increased as refiners progressively reduced the level of sulphur diesel in response to regulatory requirements of the mid-2000's.

Susceptibility of a fuel towards degradation (discoloration, formation of gums / insolubles, sediment) over time is a direct function of a fuels' chemical composition (presence and absence of certain compounds) and storage conditions (exposure to oxygen / light, temperature, trace metals, water) and as stated earlier, fuel composition as function its production origins. A further implication of this is that whilst two rail cars or terminal-tanks may both technically contain diesel, one can be more susceptible to degradation than the other because of origin and processing history. A further complication is the blending of both tanks where one blend is from one refiner, the other from another, could result in a product that is more susceptible to deterioration than the separate blends.

Fuel stability however, in most instances is not an issue, because it is produced and distributed with the expectation of being used within a reasonably short period of time – certainly within a driving season in

---

[72] Examples of accelerated aging tests to evaluate the stability of diesel are: Rancimat, PetroOxy, and ASTM D5304 (Assessing the potential long term storage stability of diesel). Also see section 13.2 page 132.
[73] An aspect not addressed in the referenced text, is the volume at which diesel has been stored. The activities suggested are more easily executed at small(er) scale and the risk low should the diesel spoil. The same may not be true for the volumes Hydro may be considering – further investigation is recommended.
[74] In refineries, a variety of products of differing chemical composition and physical properties are produced in a variety of different processes determined by the grade of crude oil(s) the refiner wishes to refine and their market objectives. Towards the end of the refining process, separate streams (combustible product in their own right) are blended together to meet a fuel's (aviation, gasoline, diesel) market specifications.

the case of North America if not sooner - within days or weeks of being produced. The requirement for a fuel to be stable for extended period e.g. beyond a year might be argued to be outside of the usual.

This is not to say that fuel cannot be stored for extended periods, just that it is unusual and certain actions are required (inventory management (first-in-first-out), inerting, filtering / addition of stabilizers to preserve fuel quality), but the aforesaid is used to illustrate that managing a large volume of fuel in the circumstances Hydro has suggested may pose challenges.

A brief review of public domain on the topic of fuel stability within the time and budget available to this study, suggests that reputable recognizable producers / brand names of fuels in general avoid or do not meaningly address the topic of fuel stability. Possible reasons for this are:

- Refiners and operators further down the supply chain to point-of-sale, avoid referring to fuel stability because the fuel can change ownership several times or is blended with product from another producer or supplier to the extent that traceability in event of a claim is problematic.
- As consequence of the above, there is no lack of companies offering additive solutions to prevent and correct the effects of fuel degradation. The technology the companies promote can be expected to be based on scientific principles, but due to factors outside of their direct control (grades of crude oil, refining technology, blending of products further down the supply chain as mentioned earlier) may temper their ability to manage fuel quality.
- An important aspect of this segment of the market to note: the refiners themselves may not be active in parts of diesel TS&D, to the extent that they may be reluctant to offer warranties for stability; as consequence are only willing to provide guidelines.

The implication of the above, is that a fuel supplier (refiner, distributor) is unlikely to contractually offer a 'shelf-life' warranty for the reasons stated.

So how can Hydro address the topic of fuel stability where they wish to store fuel at bulk for periods approaching and possibly longer than a year?

- Avoid questionable fuels that are known to be unstable, for example:
  - Biodiesel by virtue of composition and production technology is known to be unstable and is more unstable than renewable [HDRD] diesel,
  - Avoid biodiesel blends,
  - If HDRD diesel is to be used, source product from a reputable producer, and
  - Unless audited, avoid suppliers that may be blending renewable biodiesel.
  - Long-term storage upwards of twelve months of diesel by circulation, filtering, inerting and biocides if necessary, is common practise in industry and for mission critical situations such as civil and national defence. Having designed tankage in Canada's far north where long-term storage is a requirement by default, Stantec can provide further recommendations for consideration by Hydro.

- Where possible, select fuels that are stable or have a lower likelihood of degrading. Examples of possible fuels are:
  - Ethanol is one example, there is however a trade off in terms of the volume requirement (Section 7.2 page 95) and market factors outside the scope of the present study that could impact supply availability in the medium to long term. By example: sustainable aviation fuel can be produced in a process named ‘Alcohol-to-Jet’ (ATJ). Should ATJ become commercially viable it will likely see more ethanol production in the market, but it will also drive ethanol demand to the extent that supply may be constrained. Whether such a market develops and evolves in the future is open to speculation. It is noteworthy however to highlight that the US DOE suggested the US has a need for 400 to 500 biorefineries [ethanol plants] by 2050 (ABLC, 2023)[75]. Should this number of plants be built and if Hydro was able to circumvent the volume aspect, ethanol might be a consideration for Holyrood as switching fuel should diesel availability become a concern at some future time.
  - Hydrogen: the trade off on H_2 is the practical aspects on production, storage and transport; see section 7.4.3 page 104104 for further information.
  - Ammonia: whilst ammonia may alleviate some of the transport and storage challenges presented by H_2, it for the present is not a commercially proven turbine fuel. See the relevant subsection (‘Ammonia’) under ‘Hydrogen’ in section 7.4.3 page 104104107 for further information.
  - Inventory Management and Product Monitoring: establish a proactive management program via a reputable vendor at Holyrood.

7.4 CLEAN FUELS

For completeness, a list of clean(er) fuels and/or fuel components is provided below.

- Biodiesel
  - Fatty Acid Methyl Ester (FAME)
  - Fatty Acid Ethyl Ester (FAEE)
- Renewable Diesel
  - Hydrogenation Derived Renewable Diesel (HDRD) / Hydrogenated Vegetable Oil (HVO)
- Hydrogen
  - SMR / ATR / Electrolysis
- Natural Gas (NG)
  - Biogas / Renewable natural gas (RNG)
  - Compressed Natural Gas (CNG)
  - Liquified Natural Gas (LNG)

---

[75] ABLC 2023, Advanced Bioeconomy Leadership Conference March 2023. Michael Berube Deputy Assistant Secretary Sustainable Transportation and Fuels, Department of Energy

- Oxygenates (usually fuel additives)
  - Butanol, Ethanol
  - Alcohols: Ethanol, Butanol (iso, normal), Methanol
  - Ethers: Dimethyl ether (DME), Ethyl tertiary-Butyl ether (ETBE), Polyoxymethylene Dimethylether (PODE)
- Refinery
  - Alkylate / Avgas
  - Octane(s)
- Synthetic fuels
- Diesel
  - Kerosene / Synthetic Paraffinic Kerosene (SPK)
- Sustainable Aviation Fuel (SAF)
  - Spark Ignition
  - Jet

The following introduces each fuel type and ends with key considerations and market fit.

7.4.1 Biodiesel and Renewable Diesel

Broad use of the terms including biodiesel, renewable diesel and synthetic diesel or kerosene can be misleading. For this reason, synthetic diesel as produced by the gasification of biomass (agricultural, forest residue) and FT synthesis is dealt with separately in Section 7.4.6 page 117 117.

As regards to biodiesel and renewable diesel, these are classified as follows:

- 1st Generation or traditional biodiesel
  - Fatty Acid Methyl Ester (FAME)
  - Fatty Acid Ethyl Esters (FAEE)
- 2nd Generation or next generation biodiesel[76]
  - Hydrogenation Derived Renewable Diesel (HDRD), or
  - Hydrogenated Esters and Fatty Acids (HEFA), or
  - Hydrogenated Vegetable Oil (HVO)

Somewhat misleadingly, FAME / FAEE is commonly referred to as ‘biodiesel’ and HDRD as ‘renewable diesel’ despite that both are produced from renewable fats/oils. For this reason and to avoid confusion, a description of the various types of biodiesels’ is provided in Table 38. Key aspects to note are: 2G technologies all strive to produce a product that is as close to identical to fossil derived diesel (a ‘drop-in

[76] In this report ‘next generation biodiesel’ is referred to as “Renewable Biodiesel’.

fuel') as possible to minimize supply chain disruption (blending, transport, and use). Unlike 1G (esterification), 2G biodiesel technology involves multiple and chemically more sophisticated process steps along with the need for hydrogen. The latter, along with the earlier supply chain factors, play a determining role as to where 2G biodiesel plants can practically locate.

Although biodiesel is the primary product, 2G technology produces marketable co-products. The ability to produce more of one and less of another product is a function of the technology (licensor), location and market ambitions of the licensee.

Due to the nature of 2G technologies (cost / complexity), the technologies tend to be the domain of globally reputable technology developers (not operators) and licensors such as Axens IFP. Licensees, in turn are mostly reputable companies with existing refining and fuel retail operations (distribution, forecourts – parent owned and or franchised), with entrepreneurial and venture capital led ventures more the exception than the rule.

No	Abbreviation	Description	Process Steps	Feedstock options	Products (bio)	Product properties	Product		Market		Licensor / Technology developer
							TRL	CRL	TRL	CRL	
1	FAME	Fatty Acid Methyl Ester	(i) Pretreatment (removal of free fatty acids) (ii) Esterification (acid or alkali catalyzed) of the feed oil with methanol (iii) Separation to yield raw product(s) (iv) Product cleanup	Triglycerides (fats) from: oil seeds (canola / rape, palm, soy, sunflower), used cooking oil, waste animal fats	Diesel Glycerol (crude)	Paraffinic: No. Stability: susceptible to oxidation / sediment formation / gumming. Aromatics - zero Olefins (double bonds) - present Oxygenates - present (in form of esters) Sulfur - zero Properties: also a function of feedstock composition	10	6	10	6	various (a)
2	HDRD	Hydrogenation Derived Renewable Diesel	See HEFA / HVO		-	-	-	-	-		-
3	HEFA or HVO (and Hydro de-Waxed HVO)	Hydrotreated Esters and Fatty Acids or Hydrotreated Vegetable Oil	(i) Pretreatment (ii) Hydrogenation (of double bonds) (iii) De-oxygenation and de-Carboxylation (by hydrogenation) (iv) Cracking and Isomerisation (de-waxing) (v) Product separation and cleanup		Diesel Naphtha Aviation fuel (component) Propane (LPG)	Paraffinic: Yes Stability: stable Aromatics - zero Olefins (double bonds) - none Oxygenates - trace Sulfur - zero	10	6	10	6	Axens IFP, Haldor Topsøe, Honeywell UOP, Neste Oil
4	LTH	Lipid to Hydrocarbons	(i) Pretreatment (ii) Hydrolysis of the Fatty Acids to yield the free acids or salt, and water (iii) Decarboxylation and Cracking to yield Alkanes and Alkenes [olefins] (iv) Product separation to yield raw product(s) (v) Product cleanup		Diesel Naphtha Light gasses (propane, other)	Paraffinic: Yes Stability: stable Aromatics - zero Olefins (double bonds) - trace Oxygenates - none Sulfur - zero	8	3	6-7	1	Forge Hydrocarbons

(a) Not identified due to time constraint

Reference(s)	Stantec

Table 38 Biodiesel Types

The properties of the final marketable biodiesel as blend-stock (Bx) or B100 (HDRD) is direct function of the selected conversion technology and feed. In the context of FAME, it is key to acknowledge that whilst all feeds fall into the broad classification of 'fats and oils', at a chemical level they vary considerably; Figure 48. Companies with an established presence in refining, and diesel-retail will preferentially seek out large and stable volumes of singular feed for commercial and technical reasons. Consequently, it can be argued this is a key reason why established refiners have and will preferably follow(ed) 2G technologies that have a consistent supply chain (E.g., canola oil, soy) and a final product that closely mimics traditional diesel; Table 10 page 25.

7.4.1.1 Key Considerations and Market Fit

The primary motivator for 2G technology is to address the shortcomings of 1G product, this is particularly relevant to Canada where winter dictates that Cold Flow Property (CFP) and Pour Point (PP) must be different to that permitted in warmer climes. In short, the 1G product does not readily meet northern requirements for usage in Canada. Whilst constraints in 1G diesel can in part, be mitigated by judicious blending with traditional diesel along with use of fuel additives this will only take one so far as technology permits. 2G technology in contrast, seeks to avoid the constraints of 1G product from the start, by systematically removing the problematic aspects of the incumbent feed, and to produce a product that is as near too identical to what the Canadian market currently produces and can accept.

Common Names	Caproic 6:0*	Caprylic 8:0	Capric 10:0	Lauric 12:0	Myristic 14:0	Palmitic 16:0	Palmitoleic 16:1	Stearic 18:0	Oleic 18:1	Linoleic 18:2	Linolenic 18:3	Arachidic 20:0	Gadoleic 20:1	Behenic 22:0	Erucic 22:1
Canola1	—	—	—	—	—	4	—	2	56	26	10	—	—	—	—
Cottonseed	—	—	—	—	—	27	—	2	18	51	Trace	—	—	—	—
Peanut	—	—	—	—	—	13	—	3	38	41	Trace	—	3	—	1
Olive	—	—	—	—	—	10	—	2	78	7	—	—	—	—	—
Rice Bran	—	—	—	—	—	16	—	2	42	37	1	—	—	—	—
Soybean	—	—	—	—	—	11	—	4	22	53	8	—	—	—	—
Sunflower	—	—	—	—	—	5	—	5	20	69	—	—	—	—	—
Sunflower, High Oleic	—	—	—	—	—	4	—	5	81	8	—	—	—	—	—
Palm	—	—	—	—	—	44	—	4	39	11	—	—	—	—	—
Cocoa Butter	—	—	—	—	—	26	—	34	35	3	—	—	—	—	—
Rapeseed *(B. campestris)*	—	—	—	—	—	4	—	2	33	18	9	—	12	—	22
Rapeseed *(B. napus)*	—	—	—	—	—	3	—	1	17	14	9	—	11	—	45
Mustard	—	—	—	—	—	4	—	—	22	24	14	—	12	—	20
Coconut	0.5	9	6.8	46.4	18	9	—	1	7.6	1.6	—	—	—	—	—
Palm Kernel	—	2.7	7	46.9	14.1	8.8	—	1.3	18.5	0.7	—	—	—	—	—
Jatropha curcas 2	—	—	—	—	—	12.8	—	7.8	44.8	34	—	—	—	—	Other: 1.1
Pig	—	—	—	—	1	24	3	13	41	10	1	—	—	—	—
Beef	—	—	—	—	4	25	5	19	36	4	Trace	—	—	—	—
Sheep	—	—	—	—	3	21	2	25	34	5	3	—	—	—	—
Chicken	—	—	—	—	1	24	6	6	40	17	1	—	—	—	—
Turkey	—	—	—	—	1	20	6	6	38	24	2	—	—	—	—
Lard3	—	—	Trace	<0.5	1.5	24-30	2-3	12-18	36-52	10-12	1	0.5	0.5-1	—	<0.5
Beef Tallow3	—	—	—	Trace	2-4	23-29	2-4	20-35	26-45	2-6	1	<0.5	<0.5	Trace	Trace
Yellow Grease4	—	—	—	Trace	2-4	23.2	—	13.00	44.30	7.00	0.7	—	—	—	—
Yellow grease is a product from rendering plants, as well as waste oils and greases from restaurants. The fatty acid composition varies significantly depending on the source.															

* The first number designates the number of carbon atoms and the second number designates the number of double bonds.

1 *Unless otherwise indicated, this information comes from: DeMan, John M.: "Principles of Food Chemistry (3rd Edition)," Springer – Verlag, http://www.knovel.com/knovel2/Toc.jsp?BookID=1093&VerticalID=0*

2 *Shweta, Shah, Shweta, Sharma, and Gupta, M.N.: "Biodiesel Preparation by Lipase-Catalyzed Transesterification of Jatropha Oil," Energy Fuels 18, 1, 154-159, (2004).*

3 *Handbook of Indices of Food Quality and Authencity, Singhai, R.S., Kulkarni, P.R., and Rege, D.V., Woodhead Publishing Limited, Abington Hall, Abington, Cambridge, CB1 6AH, England, (1997).*

4 *Organic Chemistry, W.W. Lindstromberg, D.C. Health and Co., Lexington, MA, (1970).*

Reference: Diesel Fuels Technical Review, Chevron publication; PDF page no. 46. https://www.chevron.com/-/media/chevron/operations/documents/diesel-fuel-tech-review.pdf

Figure 48 Chemical Composition of Fats, Grease, and Oil Seeds

7.4.2 Biomass

Biomass is not presented as a viable alternative fuel for Holyrood; it is referenced here as a necessary preamble to certain fuel types as is discussed below.

From a practical perspective, both technically[77] and commercially, determining what can realistically be done with biomass is a function of: biomass type, availability (quality, volume), location of the biomass itself, the delivered price, the market, and product(s) being targeted. By example: direct use of biomass in the form of wood pellets for its energy value by combined heat and power (CHP) is reasonably straight forward. In contrast, indirect use via gasification and conversion of produced syngas to liquid fuels like DME, methanol or synthetic kerosene (diesel, aviation fuel) is considerably more technically complex in which the practical factors referenced earlier become increasingly important.

The indirect use of biomass is discussed separately as follows:

- Dimethylether (DME) – Section 7.4.5.2.1 page 116
- Methanol – Section 7.4.5.1 page 114
- Synthetic Kerosene – Section 7.4.6 page 117

7.4.2.1 Key Considerations and Market Fit

It is naturally only via the indirect use of biomass that Hydro might evaluate one of the three products mentioned above (DME, methanol or synthetic kerosene) as possible alternative.

Whilst all three might be expected to be used in a GT with some adjustment (not quantified), the reality of this happening in the medium to longer term is exceptionally unlikely for two principal reasons – lack of sufficient volumes, and should volume become available, it will most likely be directed to those markets willing and eager to pay the premium for the 'green' credentials.

7.4.3 Hydrogen

Hydrogen (H_2) is principally produced by the reforming or gasification of fossil fuels or via the electrolysis of water using electrical energy generated by solar photovoltaics and or wind turbines. Approximately 95% of H_2 produced globally (70 million tonnes, 2020) is done so via the steam methane reforming (SMR) or gasification of fossil fuels (48% NG; 30% refinery gas; 18% coal); Figure 49 and Table 39. The remaining 5% is produced by electrolysis of water (Equation 7-1) where electricity is provided from a renewable source such as hydropower, solar or wind.

Equation 7-1

$$H_2O \xrightarrow[\text{Electrolysis}]{} H_2 + \frac{1}{2}O_2$$

77 Biomass by definition has high water content and is rich in oxygenates in various forms (hemicellulose, cellulose, lignin), both present technical challenges depending on intended use of the biomass.

More than 90% of the H_2 produced currently is used for its chemical as opposed to its energetic / calorific value.

No	Description	million tonnes / annum (2022)	% Share
1	NG - reforming of	40.8	48%
2	Refinery gas - reforming of	25.5	30%
3	Coal	14.5	17%
4	Electrolysis of water	4.3	5%
5	Total (2022)	85.0	100%

Table 39 Hydrogen Production Pathways

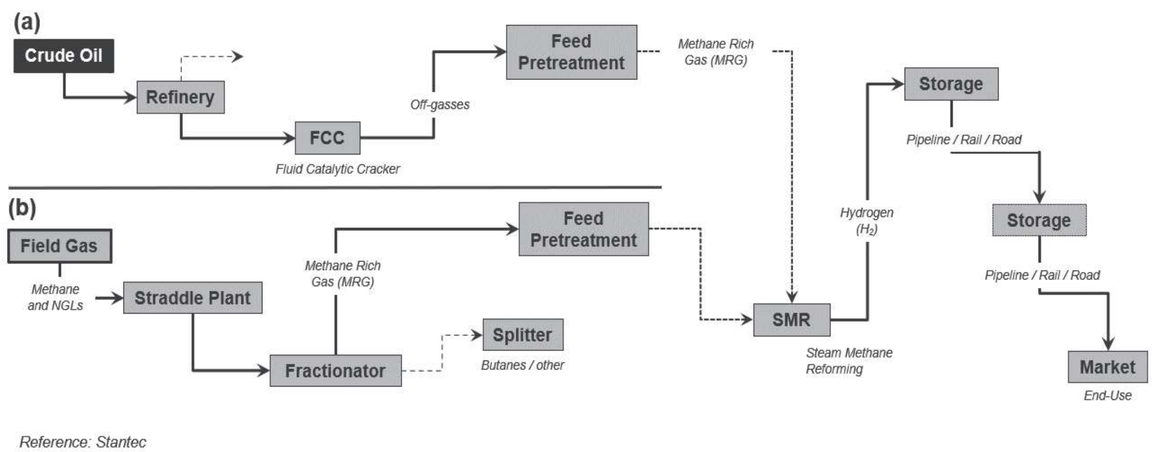


Figure 49 Hydrogen Production – Conventional Technology

Canada recently acknowledged the socio-economic potential of H_2 by launching a National Hydrogen Strategy[78]. Early studies indicate that Canada's H_2 production by 2050 could grow several times relative to current production.

Canada's Federal and Provincial governments are supporting the development and use of alternative H_2 production processes that will not use fossil fuels and hence not require CCS. Conceptual examples of alternative feeds with technologies by which H_2 may in the future be produced are (Figure 50):

- Agricultural / forestry residue gasification with production of syngas
- Renewable natural gas (sewage)
- Electrolysis of water

[78] https://www.nrcan.gc.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

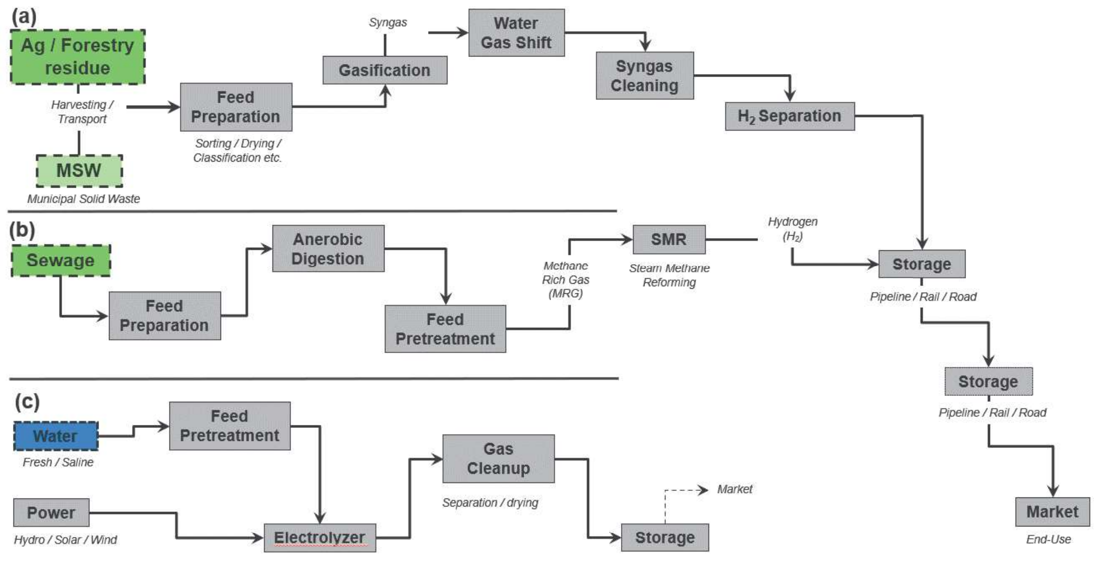
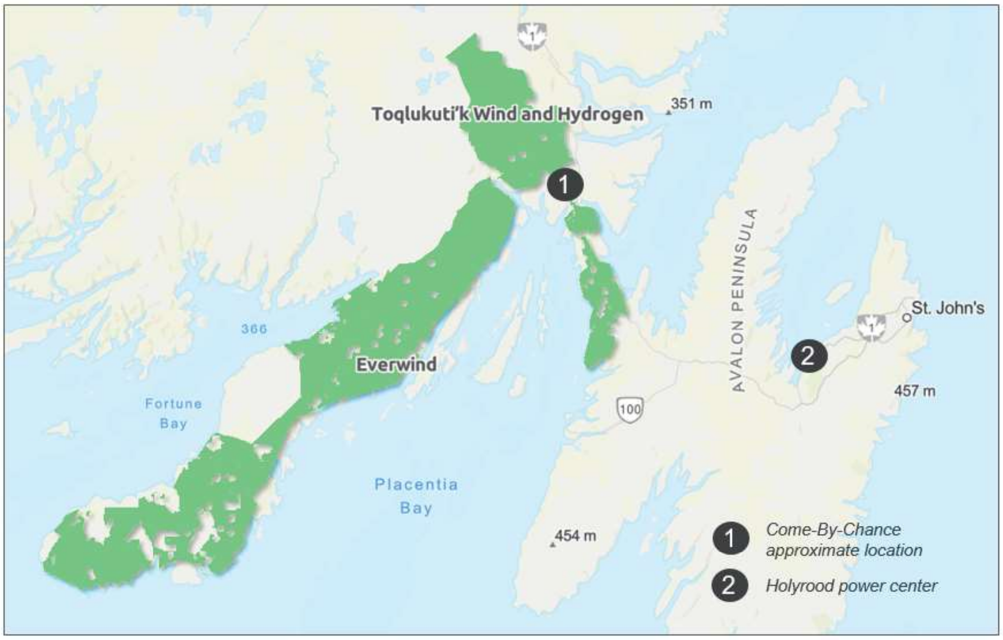


Figure 50 Hydrogen Production – Emerging Technology

A review of conventional production routes (Steam Methan Reforming - SMR, Autothermal Reforming – ATR, Partial Oxidation / Gasification – POx / GZN) and alternative routes to black or grey-H_2 is beyond the scope of this report.

For the purposes of the study, the specific focus is to ask - whether green-H_2 produced in the general area of Come-By-Chance (Figure 51) via wind energy as enabled by prospective projects, might serve as an alternative green fuel for the Holyrood gas turbines. The following section explores this in more detail.



Reference: Crown Land Call for Bids for Wind Energy Project. https://www.gov.nl.ca/iet/bidding-on-crown-land-for-wind-energy-projects/ and https://experience.arcgis.com/experience/da629a3b486748fa9c3521af248009ce

Figure 51 Wind Energy Projects Near the Avalon Peninsula, NL

7.4.3.1 Key Considerations and Market Fit

Production of Hydrogen

Society is asking power and fuel producers to reduce and/or eliminate their GHG emissions. As per the governmental requirements being imposed on all energy-based activities by the Canadian Federal Government and/or by respective Provincial Governments, entities need to abide by emissions requirements or pay imposed penalties.

The use of green H_2 produced from renewable energy, such as from wind and/or solar power and in some cases, including hydro or nuclear power will significantly reduce Scope 1, Scope 2 and Scope 3 carbon dioxide emissions.

In the following, the use of green H_2 as a substitute for diesel at Holyrood is assessed.

The amount of H_2 necessary to substitute the diesel required (on an energy basis) is assessed at 27,257 tonnes for six weeks of operation at the site. This amount does not consider the amount of H_2 (less or more) required in any reciprocating motor or turbine using the fuel. The inefficiency of H_2 used in old and new turbines is still being assessed by original equipment manufacturers (OEMs) at 100% H_2 injection.

The volume of diesel required was reported previously as 76.8 kilo-tonnes (Table 16 page 31), this translates on an energy basis to 3.3 billion MJ or 27,257 tonnes of H_2; Table 40(a) and (b) respectively with cell highlights to facilitate reading.

(a) Energy Equivalent for Holyrood - Diesel (Kilograms to Megajoules)

No	Description	Units	Unit-1	Unit-2	Total
1	Power	MW	123	150	273
2	Diesel requirement	kg	34,593,300	42,186,951	76,780,251
3	Energy equivalent	MJ	1,473,674,580	1,797,164,113	3,270,838,693
4		GJ	1,473,675	1,797,164	3,270,839
5		TJ	1,474	1,797	3,271

Diesel		
Density	*kg/l*	*0.842*
LHV	*MJ/kg*	*42.6*
Hydrogen		
Density	*kg/m3*	*0.09*
LHV	*MJ/kg*	*120*

(b) Hydrogen - Quantity required

No	Description	Units	Unit-1	Unit-2	Total
1	Energy required	MJ	1,473,674,580	1,797,164,113	3,270,838,693
2		kg	12,280,622	14,976,368	27,256,989
3		tonnes	12,281	14,976	27,257

Table 40 Energy Equivalent for Holyrood – Diesel to Hydrogen (Kilograms to Megajoules)

Independent of time, the energy equivalent required for 27,257 tonnes of H_2 is reported in Table 41.

(a) Hydrogen Production - Power required

No	Description	Units	Unit-1	Unit-2	Total
1	Hydrogen required	kg	12,280,622	14,976,368	27,256,989
2	Power required	KWh	683,170,974	833,135,330	1,516,306,304
3		MWh	683,171	833,135	1,516,306
4		TWh	683	833	1,516

Table 41 Energy Equivalent for Holyrood - Hydrogen (kWh)

The power requirement in turn to produce / liquefy one kilogram of H_2 is reported in Table 42.

(a) Power Required for Production

No	Description	Units	Value
1	Energy required	KWh/Nm3	5.0
2		KWh/kg	55.6
3	Ancillary Power	KWh/kg	0.0
4	Power requirement	KWh/kg	55.6

(b) Power Required for Liquefaction

No	Description	Units	Value
1	Liquefaction	KWh/kg	10

(c) Total Power Required = Production + Liquefaction

No	Description	Units	Value
1	Total power required	KWh/kg	65.6

Table 42 Power Required to Produce and Liquefy Hydrogen (1 kg)

The power requirement to produce the H2 onsite depends on the amount of time Hydro wants the fuel stored and at what rate it needs to be replenished. We have assessed several scenarios as discussion exercises to define any future basis of design. The scenarios have the H_2 plant operate for 365, 183, and 91 days respectively (scenarios 1, 2 and 3).

A fourth scenario has the H_2 plant operating for 323 days (365 days less 6 weeks) when Units-1 and -2 are assumed to not be operating. The respective power requirements for the scenarios (not assuming mode of supply, i.e., wind, solar, hydropower or nuclear and associated capex) add up to 173, 346, 692 and 196 MW respectively. These are considerable and clearly demonstrate the power requirement to produce green H_2 by electrolysis.

(a) Energy

No	Description	Units	H_2 Production	H_2 Liquefaction	Total Production
1	Energy requirement per assumed tonnage of H_2	KWh	1,516,306,304	272,569,891	1,788,876,195
2		MWh	1,516,306	272,570	1,788,876

(b) Scenario-1

No	Description	Units	H_2 Production	H_2 Liquefaction	Total Production
1	Assumption	Hours	8,760	8,760	8,760
2	Power	MW	173	31	204
3	Production	Days	365	365	365

(c) Scenario-2

No	Description	Units	H_2 Production	H_2 Liquefaction	Total Production
1	Assumption	Hours	4,380	4,380	4,380
2	Power	MW	346	62	408
3	Production	Days	183	183	183

(d) Scenario-3

No	Description	Units	H_2 Production	H_2 Liquefaction	Total Production
1	Assumption	Hours	2,190	2,190	2,190
2	Power	MW	692	124	817
3	Production	Days	91	91	91

(e) Scenario-4

No	Description	Units	H_2 Production	H_2 Liquefaction	Total Production
1	Assumption	weeks	6	6	6
2	Assumption	Hours	7,752	7,752	7,752
3	Power	MW	196	35	231
4	Production	Days	323	323	323

Table 43 Total Power Required for Hydrogen – Scenario 1 to 4

Hydrogen Storage

Above ground storage options for the afore-mentioned scenarios are very limited, if non-existent, on the island of Newfoundland. It is not conceivable to store this volume of H_2 in gaseous form. Based on past Stantec experience for units significantly smaller than the present scenarios, volume requirements, even at high pressures such as 350 barg or 700 barg would clearly surpass the site's available space. There are also stakeholder and safety concerns around storing so much H_2 as its energy equivalent is not to be underestimated or discounted.

We have calculated the amount of incremental power required to store the H_2 in liquid form. These needs are also presented in Table 44. The increased amount of power required for scenarios 1, 2, 3 and 4 are 31, 62, 124, and 35 MW respectively. Thus, the total amount of power required for production and liquefaction of H_2 by scenario are 204, 408, 817 and 231 MW.

These estimates do not consider the power requirements necessary for liquefaction of boil-off H_2, which is estimated at 1 to 2% of the total storage capacity, since the liquid H_2 must be maintained at minus 253°C.

Underground storage of produced H_2, in gaseous form as an alternative to above ground storage - would have to be extensively studied. Local geology would have to have salt cavern potential. The largest such storage site is Air Liquide's H_2 storage facility in Beaumont, Texas. This facility is 1,500 meters deep and has a column diameter of 70 meters. It can store 4.5 billion standard cubic feet, or 10,632 tonnes of H_2. This being the largest such facility in the world and is only 40% of the storage needs for Holyrood site.

Considerable study would have to be undertaken to assess if the geology in and around the Holyrood site is amenable, in some way, to the storage requirements of the site.

Delivery scenarios of liquid H_2, not produced on site would require over 6,800 truck deliveries to deliver the total amount of H_2 (for any specific scenario). Thus, the respective delivery schedules for each scenario mentioned above would require 19, 38, 75, and 21 trucks per day. Not considering extra trucks to ensure trouble free delivery, the amount of such specialized trucks would require considerable investment and procurement lead times. We do not consider this option as viable.

Shipment of liquid H_2, from ships, whether from Newfoundland project sites or external sources, is not considered a viable option within the next decade. Secondly, liquid-H_2 would have the same issues for storage as mentioned above in liquefaction sections.

Ammonia as Possible Solution

Another option for the storage needs of the Holyrood gas turbines is to consider ammonia as an energy source. Table 44 highlights Stantec's assessment on the use of ammonia as a diesel substitute. The underlying assumption is that the use of ammonia (as a direct fuel and not dissociated into H_2) would be possible in present and future new turbines at the site.

(a) Energy Equivalent for Holyrood - Diesel (Kilograms to Megajoules)

No	Description	Units	Unit-1	Unit-2	Total
1	Power	MW	123	150	273
2	Diesel requirement	kg	34,593,300	42,186,951	76,780,251
3	Energy equivalent	MJ	1,473,674,580	1,797,164,113	3,270,838,693
4		GJ	1,473,675	1,797,164	3,270,839
5		TJ	1,474	1,797	3,271

Diesel		
Density	*kg/l*	*0.842*
LHV	*MJ/kg*	*42.6*
Ammonia		
Density (@ minus 3° C)	*kg/m3*	*681.9*
LHV	*MJ/kg*	*18.6*

(b) Ammonia - Quantity required

No	Description	Units	Unit-1	Unit-2	Total
1	Energy required	MJ	1,473,674,580	1,797,164,113	3,270,838,693
2		kg	79,229,816	96,621,726	175,851,543
3		tonnes	79,230	96,622	175,852
4		m^3	116,190	141,695	257,885
5	+ 10% Contingency		127,809	155,864	283,673

Table 44 Energy Equivalent for Holyrood – Diesel to Ammonia (Kilograms to Megajoules)

The storage requirements for the energy needs of the site's operational targets would be approximately 284,000 M3 (assuming a 10% contingency). The requirement is well within conventional measures for ammonia storage and represents only 0.1% of the world's present grey (natural gas-based production); Table 45(a).

The amount of carbon dioxide emitted by the production of grey ammonia amounts to 2.4 tonnes CO_2 per tonne of ammonia produced. The amount of CO_2 emissions thus using ammonia at the Holyrood site is estimated at approximately 422,000 tonnes. No emissions are considered for the combustion of the ammonia at the site; Table 45(b).

These emissions are more than the expected emissions of diesel production and combustion at approximately 269,000 tonnes, Table 45(c). Emissions of CO_2 for transport of both products have not been considered. The assessment, however, does highlight the fact that green ammonia - not yet produced in any significant quantity (on a worldwide scale) - would solve the emissions issue for Hydro.

(a) Holyrood as Percentage of Global Ammonia Production

No	Description	Units	Unit-1
1	Ammonia production (global)	tonnes	200,000,000
2	Holyrood requirement	tonnes	175,852
3	Holyrood as % of global production	%	0.09%

(b) Ammonia

4	Holyrood requirement	tonnes	175,852
5	Emissions (reference)	tonnes CO_2 / tonne NH_3	2.4
6	Holyrood emmissions grey-NH_3 [(a)]		422,044

(c) Diesel

7	Holyrood requirement	tonnes	76,780
8	Emissions (reference)	tonnes CO_2 / tonne Diesel	3.5
9	Holyrood emmissions (transport excluded)		268,731

(a) The emmisspns referred to are those from the production of NH_3 from natural gas and not combustion at Holyrood.

Table 45 Holyrood: Ammonia versus Diesel Emissions - Comparison

Green ammonia projects are being considered in Newfoundland, across the Atlantic provinces, Quebec, across the US Gulf Coast and in Europe. If such projects do proceed, Hydro could consider such procurement options. With proper inerting, long-term storage of ammonia would be possible. It must be stated however, that toxicity assessments and HAZOP (Hazard and Operability) studies would have to be completed to assuage stakeholder and community concerns to achieve social acceptability for such a project to occur.

Table 46 provides an assessment of the approximate number of loadings and shipments needed for the volume of ammonia required.

No	Description	Units	Value	Loadings / Shipments
1	Ammonia requirement at Holyrood	m^3	283,673	-
2	Ship-1	m^3	15,000	18.9
3	Ship-2		30,000	9.5
4	Ship-3		60,000	4.7
5	Ship-4		85,000	3.3

Table 46 Ammonia Shipment

7.4.4 Natural Gas - Compressed and Liquified

Compressed NG (CNG) and liquified NG (LNG) is NG (fossil or renewable NG) that has been cooled down to a liquefied, transportable state. Referred to as a ‘virtual pipeline’ this allows NG to be transported to locations not served by pipelines; Figure 52.

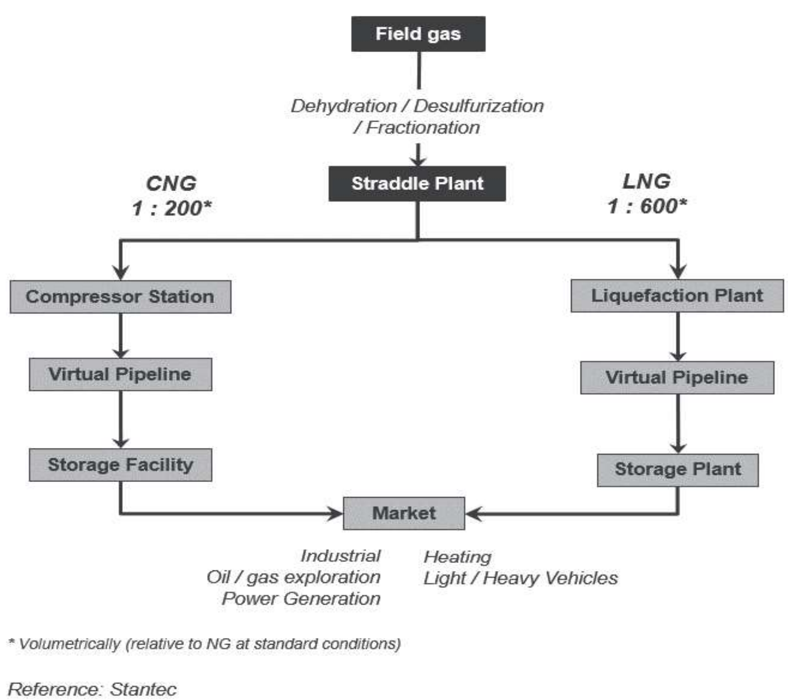


Figure 52 CNG and LNG Virtual Pipeline

7.4.4.1 Key Considerations and Market Fit

In the right circumstances and with recent developments in infrastructure that allow for efficient, cost-effective storage and transportation, CNG and LNG can be a competitive fuel choice. Whilst CNG / LNG certainly has appeal to reduce the carbon footprint, the length and robustness of the supply chain necessary into, and along with the absence of gas infrastructure (terminal, distribution) in Newfoundland makes both forms a questionable and highly unlikely viable option practically, and again so, when considered against present regulatory initiatives and social pressure for decarbonization.

7.4.5 Oxygenates

Oxygenates is a collective term and refers to classes of fuels that include alcohols and ethers. Because they differ in terms of their chemical and physical properties (boiling / freezing points, flame speeds, solubility, surface tension (affecting the spray patterns in the combustion chamber), vapor pressure, miscibility, combustion pathways), they do not combust in the same way and are thus discussed separately below.

7.4.5.1 Alcohols

Ethanol from corn or wheat is the most common of the ‘alcohols’ to be produced commercially at large scale for use as a gasoline additive; Table 13 page 29. Technically the term ‘alcohol’ refers to a class of chemicals that are or may be produced by a variety of renewable or not technologies either as primary or coproduct; Table 47.

A description of commercial (CRL) and technology readiness level (TRL) is provided in Section 9.5 page 130 of the appendix.

No	Chemical	Description	Feedstock options	Products (bio)	Product properties / Market	Production		Market		Licensor / Technology developer
						TRL	CRL	TRL	CRL	
1	Acetone, Butanol, Acetone (ABE)	Production of a ABE via the fermentation of spent brewers (distillers) grains	Distillers grains (DGs) Spent Brewers Grains (SBG)	Acetone Butanol (normal) Ethanol	Components of ABE have value as a green derived chemical and as a fuel. 2019 papers have reviewed the use of ABE in gasoline and diesel.	10	6	4	1	Various Celtic Renewables (UK)
2	Ethanol (1G)	Fermentation of grains	Wheat, wheat starch, corn, barley, rye & triticale	Ethanol Fusel Oils Distillers grains	Established blendstock in gasoline	10	6	10	6	know-how
3	Ethanol (2G)	Fermentation of non-food feedstocks	Agricultural & forestry residue (lignocelluloses)	Ethanol		7-10	6	10	6	know-how
4	Butanol (iso)	Fermentation	Corn (1G) Agri-waste (2G)	Butanol (iso)	Blend stock into marine [pleasure craft] gasoline. Feedstock for: production of green-Octane and SAF	9	3	10	4	Butamax (BP, Dow JV) Gevo Inc.
5	Fusel Alcohols	Co-product of conventional ethanol fermentation.	Wheat, wheat starch, corn, barley, rye & triticale	n-Butanol iso-Butanol iso-Pentanol	Range of Carbon numbers both linear and branched which theoretically improve the combustion process and reduce particulate emissions	10	1	3	0	-
6	Methanol	Syngas (CO + H2)	NG or RNG	Methanol	With exception of China, not conventionally used as a straight fuel or additive to gasoline.	10	10	10	0	Haldor Topsøe Linde etc.
7	Mixed Alcohols	Syngas (CO + H2)	NG or RNG	Range of linear alcohols from Methanol (C1) to Nonanol (C9)	Range of all linear Carbon numbers, MAS theoretically improve the combustion process and reduce particulate emissions in gasoline and diesel type fuels respectively.	8	1	8	2	Dow NREL Standard Alcohols of America

Reference(s)	*Stantec*

Table 47 Alcohols as Fuel / Blend-stock

Ethanol for historical reasons in North America, has received the most attention as a clean fuel and gasoline additive.

7.4.5.1.1 Key Considerations and Market Fit

Other than ethanol, with isolated examples of methanol (China; Mxx) and some exception for iso-butanol, none of the remaining alcohols listed in Table 47 have been materially positioned as a fuel additive or other. Reasons for this are likely prosaic and beyond the scope of the present study.

Of all the alcohols, and ignoring for the moment, the additional volume requirement compared to diesel (Section 7.2 page 95) bioethanol appears as the only alcohol that might be leveraged by Hydro.

7.4.5.2 Ethers

Ethers are a class of chemical compounds of which Dimethyl ether (DME) has been proposed as a substitute to diesel. Polyoxymethylene ether (PODE or OME – Oxymethylene ether) is structurally similar to DME and because of a higher carbon number would have distinct handling advantages. Both are / can be produced from syngas (Table 48) where this can in turn be produced from fossil or renewable feedstocks.

No	Chemical	Description	Feedstock	Product(s)	Product properties / Market	Production TRL	Production CRL	Market TRL	Market CRL	Licensor / Technology developer
1	DME	Dimethyl ether	Methanol (bio or fossil) viz. Syngas ($CO + H_2$)	DME	Additive to conventional fossil based diesel	10	6	8-9	2	Haldor Topsøe Johnson Matthey (DAVY™ DME)
2	POMEs	Polyoxymethylene Ethers		OME_x	Combustion, soot reducing additive	7-8	2	10	0	OME Technologies GmbH [(a)], other (E.g. patents - BASF, Du Pont, Sinopec)

Reference(s) / Notes
Stantec
(a) Personal Communication: Prof. Dr.-Ing. Jakob Burger, Director: OME Technologies GmbH. Schlehweg 25a, 67661 Kaiserslautern. Mobil: +49 151 2278 4747. Amtsgericht Kaiserslautern, HRB32051

Table 48 Dimethyl Ether and Polyoxymethylene Ethers

7.4.5.2.1 Dimethyl Ether

DME has been considered and promoted as a substitute to traditional diesel by numerous entities:

- Enerkem[79]
- International DME Association website[80]
- Oberon Fuels[81]

7.4.5.2.2 Key Considerations and Market Fit

Whilst not conclusive, DME however, does not appear to have or be winning widespread acknowledgement nor adoption as a diesel substitute. Possible reason for this could lie in some of the disadvantages it presents (Figure 53) along with the fact that biodiesel as competing product, presents itself as being more readily available, and importantly more widely compatible with existing supply chain infrastructure and engine technology.

[79] https://www.canadianbiomassmagazine.ca/enerkem-produces-bio-alternative-to-diesel-fuel-7025/
[80] http://www.aboutdme.org/news-media-o
[81] https://oberonfuels.com/

(A)

Properties	DME	Diesel fuel
Chemical formula	CH_3–O–CH_3	-
Molar mass [g/mol]	46	170
Oxygencontent [% w/w]	34.8	0
Carbon-to-hydrogen ratio	0.337	0.516
Cetanenumber	55–66	40–50
Low calorific number [MJ/kg]	27.600	42.5
Viscosity [cP]	0.15	2
Density [kg/m^3]	660	831
Auto-ignitiontemperature [K]	508	523
Boiling point [K]	248.1	450–643
Stoichiometric air-fuel mass ratio	8.9	14.6

Boiling point

- Diesel 177 - 370 ºC
- DME minus 25 ºC

(B)

Advantages	Disadvantages
High oxygen content – smokeless combustion	Low combustion enthalpy
Low boiling point - quick evaporation when a liquid-phase DME spray is injected into the engine cylinder.	Low viscosity – could provide to dysfunction of the conventional film bearing between the Needles and sleeve of the injector, and this will cause leakage and wear and tear of parts
High cetane number - good fuel for auto ignition	Lowmodulus of elasticity
Can achieve ultra-low emissions	Low boiling point – requires the use of a pressurized system to maintain the fuel in liquid state
Better energy efficiency	Low energy content – large fuel tanks
Lower exhaustgasreactivity	
Multi-source and multipurpose fuel	

Reference: Dimethyl Ether as a Potential environmental friendly fuel. Patrycja Makoś et al. Gdansk University of Technology, Faculty of Chemistry, Department of Process Engineering and Chemical Technology, ul. G. Narutowicza 11/12, 80-233 Gdansk, Poland

Figure 53 Dimethyl Ether – Properties, Advantages and Disadvantages

7.4.6 Synthetic Fuels

The term 'synthetic fuel' or 'synfuel' specifically refers to diesel and kerosene (also referred to as Synthetic Paraffinic Kerosene (SPK)) produced from syngas (carbon monoxide and hydrogen) via the Fischer-Tropsch (FT) process. For FT, syngas has commercially and historically been produced from coal by gasification and later by the reforming of NG.

In more recent times due to economic opportunity and environment concerns, considerable attention has and continues to be given to the production of syngas and hence 'synfuels' in general and aviation fuel in particular from:

- Agricultural or forestry biomass (ideally residues / waste),
- Non-compostable MSW,
- Renewable NG, and
- Air captured CO_2 and H_2 produced via electrolysis of water with green-power.

Whilst strict definitions are at times necessary, some latitude on occasion is warranted, as there are fuels in addition to SPK, that by definition are synthetic, examples are:

- Methanol
  - Enerkem (Edmonton): reportedly produces methanol from syngas as produced by gasification of MSW[82].

[82] https://enerkem.com

– Whilst not widely regarded as a blend-stock for gasoline nor as a full gasoline substitute in the form of M100, the latter has been developed as a gasoline alternative in China[83] and has also been promoted as a maritime fuel[84].

7.4.6.1 Synthetic Diesel

For a variety of historical reasons, the two companies Sasol and Shell have led the way globally in developing and commercializing FT technology; Table 49.

No	Company	Location	Capacity (bpd)	Status
1	PetroSA	Mossel Bay	45,000	Long term status in question re gas availability
2	Sasol	Sasolburg	24,000	operating
4		Secunda	160,000	operating
5		Qatar ("Oryx")	34,000	operating
6		China	2 x 80,000	cancelled (Nov, 20110/11)
7		Australia	-	discontinued
8		Canada	40,000 or 80,000	cancelled (Nov, 2017)
9		India	-	discontinued
10		Nigeria (Escravos GTL)	34,000	operating
11		USA (Louisana)	96,000	cancelled (Nov, 2017)
12		Uzbekistan	37,000	Startup - 4Q21
13	Shell	Malaysia	14,700	operating
14		Qatar ("Pearl")	140,000	operating
15		USA	100,000	cancelled (Dec, 2013)
	Reference(s)	*Stantec*		

Table 49 Synfuel Plants

Both companies have traditionally followed a full-inhouse technology and commercialization model covering primary production, production separation and product utilization (Shell – Base oils → full synthetic lubricants; Sasol → specialty waxes). Until 2013 and 2017, Shell[85] (140,000bbl./day) and Sasol (96,000 bbl./day) were considering large GTL projects in N America. Both projects were shelved for a variety of reasons. High CAPEX and the low differential between NG and crude oil being likely candidates[86, 87].

The following illustrates the commercial development of FT has not been without its share of challenges:

- Rentech: declares Chapter 11; Dec 2017[88]

---

[83] Methanol Fuel In China – 2020. Published by: China Association of Alcohol and Ether Fuel and Automobiles (CAAEFA) March 2021. URL: https://www.methanol.org/wp-content/uploads/2020/04/China-Methanol-Fuel-Report-2020_final-1.pdf
[84] https://www.methanol.org/marine-fuel/
[85] https://www.greencarcongress.com/2013/09/20130925-gulfgtl.html
[86] https://www.reuters.com/article/shell-gtl-cancel-idUKL2N0JK1S520131205
[87] https://www.reuters.com/article/sasol-strategy-idUSL8N1NS5WI
[88] https://www.businesswire.com/news/home/20171219005555/en/Rentech-Files-Voluntary-Petition-Relief-Chapter-11

- Syntroleum Corp.: with a history dating back to 1984, and a long development history Syntroleum was acquired by Renewable Energy Group in Dec. 2013[89]
- Whilst FT diesel[90] has the advantage of low emissions, low aromatics, high cetane, and low sulfur, it is not a fully market fungible / direct-drop-in fuel due to certain limiting properties -
  - Low aromatics as related to in-engine seal compatibility – (Kramer et al; 2022)[91]
  - Lower density: in comparison to market specification diesel, FT-diesel has a lower density and must be blended with a product of higher density before being sold to market. See also: US 7,345,210 B2: Blending For Density Specifications Using Fischer-Tropsch Diesel Fuel. Assignee: ConocoPhillips Company.
  - Poor(er) lubricity due to the lack of polar groups[92].

That being said FT has its merits, has and will no doubt continue to reposition:

- 2021, Sept.[93]: Sasol revises their approach to the market and expands their collaboration with Haldor-Topsøe[94] to include 'Power-to-Fuels'.
- 2022, April[95]: Sasol and Uniper[96] (Sweden) announce plans for a Sasol ecoFT SAF facility from biomass and clean H_2 in the municipality of Sollefteå.

7.4.6.1.1 Key Considerations and Market Fit

Without promotion and support translating into the building of large-scale plant (e.g. 80,000bpd), synthetic FT fuels are unlikely to easily present a near-term clean-fuel (diesel / SAF) solution for Canada. Should a facility be built at some future time, it can be expected the focus will be on aviation fuel. Due to business, contractual and general competitive factors, it would be unlikely Hydro could expect to procure the volumes it would require. Also see section 7.4.6.3 page 120.

---

[89] https://www.businesswire.com/news/home/20131217006512/en/Renewable-Energy-Group-Inc.-Agrees-to-Acquire-Syntroleum-Corporation
[90] Shell GTL diesel product information; http://www.kbl.dk/Shell%20GTL%20Fuel%20Product%20Info_DK%20(English%20version)%202016-11.pdf
[91] Perspectives on Fully Synthesized Sustainable Aviation Fuels: Direction and Opportunities; Stephen Kramer et al. Pratt & Whitney, West Hartford, CT, United States. Frontiers in Energy Research. Published: 24 January 2022 doi: 10.3389/fenrg.2021.782823
[92] Enhancing the lubricity of gas-to-liquid (GTL) paraffinic kerosene: impact of the additives on the physicochemical properties. Hani Ababneh et al. Chemical Engineering Department, College of Engineering, Qatar University, 2713 Doha, Qatar. BMC Chemical Engineering. 2020. URL: https://doi.org/10.1186/s42480-020-00032-2
[93] https://www.sasol.com/media-centre/media-releases/sasol-haldor-tops-e-expand-g2l-licensing-collaboration-grow-sustainable
[94] https://www.topsoe.com/our-resources/knowledge/our-products/process-licensing/g2ltm-efuels-technology
[95] https://www.sasol.com/media-centre/media-releases/sasol-ecoft-and-sweden-s-uniper-partner-produce-sustainable-aviation
[96] Uniper is a Swedish company with ≈33GW of generating capacity in Europe and Russia; has interests in LNG, nuclear, solar and wind.

7.4.6.2 Synthetic Kerosene

Applied in the context of FT technology, synthetic kerosene has similarities to aviation fuel and diesel and should be applicable to use in a GT.

7.4.6.3 Key Considerations and Market Fit

In contrast to conventional crude oil refineries, synthetic fuels are produced in facilities whose common denominator is syngas. The syngas can be non-renewable (fossil NG derived), renewable (biomass derived), or shade thereof (municipal solid waste (MSW) derived).

A particularly favorable feature of synthetic fuels is the fact that they are or can be made to ‘drop-in’ to the existing supply chain and end-use market. Whilst the technical properties of the product remains true, in practical terms reality is considerably more challenging and costly from a production perspective. In a world that has ≈100 million barrels of refining capacity, there are less than ten large scale synthetic products plants globally, developed and built by two principal companies of long-standing expertise in this technical field with a combined refining capacity of ≈500,000 barrels / day or 0.5% of global refining capacity. This tells of the high complexity and cost of building and operating such plants – that it is not as straight forward as might appear at first glance.

Whilst it is commonly promoted that synthetic fuels can be produced from alternative feedstocks to the proven fossil-NG route, be this from biomass or MSW, these have yet to realize in Canada or elsewhere to the extent necessary that would make it practical to source and direct said fuels to Hydro. Further, as was stated in the prior section – it would be unlikely that Hydro could expect to procure any volume of any description due to the high competition that would exist for this product.

8 SUMMARY: KEY OBSERVATIONS AND RECOMMENDATIONS

Stantec's observations and recommendations are as follows.

8.1 KEY OBSERVATIONS

Market Forecast and Availability of No.2 Diesel

The Canadian oil and gas sector linked with that of refining and fuel supply (distribution), is coming under increasing structural pressure both directly and indirectly (carbon pollution pricing, access to domestic crude, capped growth). This in the longer term causes domestic refiners to consider reducing capacity or to exit the market, at least in terms of production. Refineries may restructure sites to non-producing terminal activities of import, storage, distribution of those products and markets which remain profitable.

A factor that needs to be considered, is the size of the Canadian refining sector relative to competing jurisdictions and where the sector sees its future markets lie in terms of the products, they produce due to general circumstance. Refiners primarily producing liquid transport fuels in a decarbonizing era must ultimately ask – when do I cease production? As individual circumstance dictates, not all will close at the same time. Staying operational will depend on what market a refiner might direct its business profitably to.

The US refining sector in contrast is considerably larger than Canada's and, in some states, faced with circumstances not dissimilar to that of Canada. On numerous other metrics and qualitative considerations however, deeper comparison will demonstrate the two countries' sectors differ significantly. The outlook for US refiners consequently, if not overly positive, is at least optimistically neutral for a continuance of operations through 2050.

The strategic importance of the US refining and petrochemical sector to their economy along with international security should not be underestimated, to the extent that both sectors can be expected to be somewhat shielded from decarbonization initiatives at large, at least until a viable substitution has been identified, built, and proven. For this reason, we do not see medium and longer-term risk to the production of traditional diesel in the US.

Molière (2023)[68] comments to the importance of reliable fast start gas turbines and their role in the energy transition, speaking to the fact the transition will require back-up power systems when renewable power falters. By implication - government and society by necessity, will maintain an operating base of refineries (conventional and new) to ensure stable supply of fuel to gas turbines to cover such events.

Regulation

Canada has embraced several regulatory initiatives with real intention to reduce industrial emissions, from softer initiatives like consumer access to EV's to formal regulation on clean electricity, greenhouse gas emissions and capping growth in oil and gas production. All are likely to cause Canada's conventional refining sector to evaluate continued operations as they approach the middle years and 2050. Whether diesel or suitable fossil-based alternative produced in Canadian refineries will be available in 2040 is uncertain. What is more certain is the continued availability of both options out of US refineries for simple expediency of US economy, geopolitics and national security.

Supply Chain Processes – Risks / Improvements

A review of the supply chain to the extent possible[97] highlighted the following key risks.

Bidder response to RFPs is severely limited, with North Atlantic Refining winning the contract for the three cycles to date. On-island companies (I.e. Valero Energy and Irving Oil) not submitting supply proposals, suggests possible issues with the overall contract strategy or structure, lack of public awareness of the RFP or an erosion of the on-island supplier pool in general, as participants exit the market or restructure their business model. To secure diesel in the future, it is vital to identify barriers to bidders and to develop a larger and more diverse supplier pool. An Expression of Interest should open the door to conversations with suppliers both on- and off island, and give Hydro insight on market shifts, limitations, and opportunities.

On-island logistics is a concern through the lens of backup supply and inventory management because of the sudden and urgent nature of the need likely at the time. Trucking availability on short notice, possibly during severe weather where roadways are not open, and where accessible fuel storage is possibly scattered across the island is a concern that needs to be addressed in emergency response plans. The five-day inventory at Holyrood does provide some security, but it is recommended to investigate additional storage options closer to the gas turbines themselves to reduce or remove reliance on road transportation.

As Hydro continues operating the Holyrood gas turbine as an emergency / peak power provider, this along with the possibility of new generation capacity in the future, requires implementation of a protocol to manage procurement and product quality against fuel instability. The change in operating philosophy with a possible significant increase in diesel required also suggests Hydro explore wider procurement options. Access agreements, supplier managed inventory partnerships, or a just-in-time contracting strategy or combinations thereof, could reduce initial investment cost in inventory and Hydro's risk that comes with carrying a large inventory.

Critical Assets

Since they were first constructed, refineries have never remained static. From lighting fluid to gasoline for an emerging automotive sector, both in war and peace, refineries have evolved in fits and starts in response to the environment and global events. Modern aviation and plastics both owe their beginnings to technological discoveries and advances of World War II. Rather than close, refineries have evolved and can be expected to continue doing so.

In the past decade, those refiners with the vision and resources have responded to not only climate change concerns, but also the emergence of hybrids / EV's and the threat this poses to the traditional refining business model. Whilst refiners are likely to increase focus on chemicals, the base feedstocks

---

[97] The review was confined to the three procurement cycles to date for supply and delivery of diesel to the Holyrood gas turbines.

and processes themselves inside of refineries do not disappear. Refiners within reason, can choose which market they address.

Geopolitical events are not new and by nature disrupt the global economy. Less well known is the scale at which products of various description travel the world.

In the 1950's to the 1980's products servicing daily lives were likely to have been produced a block, county, or province over. This is less true today, crude and chemicals are examples of products traded globally to the extent that when trade is disrupted, the impact is mitigated by the availability of alternatives and the scale of the activity itself.

Demand volatility, state of the economy (interest rates, inflation) geopolitics, regional labor relations and other factors are for the most part, out of Hydro's ability to influence. The remaining option is to acknowledge such events and from that, determine how they might be mitigated.

Should supply of bulk diesel to Newfoundland be disrupted from mainland Canada or East Coast US, there are options. Supply from further afield (Europe, Africa, Japan) however, will require intentional planning and continued management.

Alternative Fuels

An 'alternative fuel' by definition, may only be classified as an 'alternative' if the candidate is able to meet the operational needs of the circumstances to which it is to be deployed - current and future.

In providing a broader description of fuels, Stantec narrowed the conversation to those alternatives that realistically might find place in Newfoundland's unique setting. For reason of physical properties, no fuel is as perfect as fossil-derived diesel appears.

Hydrogen is disqualified as an alternative on account of practical reasons relating to production, unavailable green power, viable transport and long-term storage (above and below ground) and the volume required for the existing and second turbine at Holyrood, or other location. The challenges for the present are very significant as well as likely cost prohibitive if they were not.

In acknowledgement of this, ammonia was analyzed. However, until gas turbine vendors can prove ammonia a viable fuel, it will remain an idea and a consideration utility companies can only observe with future interest.

Biodiesel as produced by the reaction of ethanol and animal fats or vegetable oils with limited further processing is disqualified on basis of the fuel not being suitable to Canadian conditions and unstable in long-term storage as function of chemical composition. Production of renewable diesel in contrast, involves multiple and chemically more sophisticated processes that can produce a product to Canadian requirements. This is not where the challenge lies however - sourcing large volumes of renewable diesel can be expected to be slightly to very challenging as producers will direct sales to markets willing to pay a premium for the privilege in their own right or as function of their own jurisdictional requirements / subsidies.

Bioethanol may be an alternative in the future. There are several references to the use of ethanol in gas turbines, however these have been in countries like Brazil that produce ethanol at large scale. Whilst ethanol has positive attributes, it is penalized by a low energy density implying 1.68 times volumetric increase compared to diesel with associated logistics and more particularly, on-island logistical implications. The volumetric constraint might be overcome with larger onsite storage delivered seasonally by barge or coastal tanker and the matter of long-term product stability addressed by storing under nitrogen.

8.2 RECOMMENDATIONS

Aspects for consideration and recommendations in no particular order are:

- Approach and interview diesel suppliers that have been expected to bid and have not; determine factors in their decision not to bid, and consider how suppliers might be incentivized to bid in future.
- Go off island for bidders: research and strategically approach terminal operators and refiners on the east Coast (Canada, US) to explore options for offshore access to inventory with short notice supply via Expression of Interest,
- Select future gas turbines with fuel flexibility or flexibility with minimal retrofit (time and cost)
- Repackage the problem: let someone else own the inventory and associated stability issue of diesel,
- Review of Holyrood operating philosophy (current / future) and cost benefit analysis against the volume requirement (diesel and alternative fuel like ethanol) – conduct a robustness test of present strategy / operating philosophy.
- Evaluate the option of refurbishing / establishing large tankage at or nearer Holyrood gas turbines (e.g. Valero Holyrood site) with seasonal delivery by barge / ship,
- Strategic On-Island Reserve: with PUB-NL as independent 3rd party, determine and monitor island diesel stock levels on a weekly and monthly basis,
- Consider available infrastructure (ports, tank storage, potential pipelines, road network, transmission line restrictions) when determining location of future backup generating facilities to streamline logistics.

9 APPENDIX

9.1 ABBREVIATIONS

ATJ	Alcohol to Jet
ASTM	ASTM International, formerly American Society for Testing and Materials
ATJ	Alcohol to Jet
B	Billion
bbl.	Barrel
bbl. / day	Barrels per day
BEV	Battery Electric Vehicle
Bn	Billion
BUP-NJ	Newfoundland and Labrador Board of Commissioners of Public Utilities
Bxx	Final products of biodiesel with ultra-low sulphur diesel; xx = the percentage biodiesel in the blend.
CI	Carbon intensity
CBC	Come-by-Chance
CFP	Cold Flow Property
CGSB	Canadian General Standards Board
CRL	Commercial Readiness Level
CAF	Canadian Fuels Association
CAPP	Canada's Oil and Natural Gas Producers
CO_{2eq}	Carbon dioxide equivalent
CFS	Clean Fuel Standard
CGSB	Canadian Government Standards Board
CNG	Compressed Natural Gas
CRL	Commercial Readiness Level
DGE	Diesel gallon equivalent
DOE	Department of Energy
EIA	Energy Information Administration
ECCC	Environment and Climate Change Canada
EPA	Environment Protection Agency
ETBE	Ethyl tertiarybutylether
ETS	Emissions trading system
EU	European Union
EV	Electric Vehicle
Exx	Final product containing ethanol; xx refers to the percentage of ethanol in the blend.

FAAE	Fatty Acid Alkyl Esters
FAME	Fatty Acid Methyl Esters
FT	Fisher-Tropsch
1G	First generation
GHG	Greenhouse Gas
GT	Gas turbine
GTL	Gas-to-Liquids
HAZOP	Hazard and Operability
H_2	Hydrogen
HDO	Hydrodeoxygenation
HDRD	Hydrogenation Derived Renewable Diesel
HFO	Heavy Fuel Oil
HVO	Hydrotreated Vegetable Oil
Ito	In terms of
JIT	Just in Time
LCFS	Low Carbon Fuel Standard
LH2	Liquid hydrogen
LIL	Labrador-Island-Link
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
MAS	Mixed Alcohols
MDF	Methanol Direct Fuel
MW	Megawatt
Mxx	Final product containing methanol; xx refers to the percentage of methanol in the blend.
MSW	Municipal Solid Waste (non-compostable / not organic)
NGLs	Natural Gas Liquids
NRCAN	Natural Resources Canada
OMEs	Oxymethylene ethers
PHEV	Plug-in hybrid Electric Vehicle
POMEs	Polyoxymethylene Ethers
PP	Pour Point
ppm	Parts per million
RFO	Renewable Fuel Oil
RFP	Request for Proposal
RFS	Renewable Fuels Standard
RNG	Renewable Natural Gas

RRA	Reliability and Resource Adequacy
RVP	Reid Vapor Pressure
SAF	Sustainable Aviation Fuel
2G	Second generation
SI	Spark Ignition
SPK	Synthetic Paraffinic Kerosene
TAN	Total Acid Number
TRL	TRL – Technology Readiness Level
TS&D	Transport, storage and distribution
ULSD	Ultra-Low Sulfur Diesel
ULSK	Ultra-Low Sulphur Kerosene
WEC	Waste Emissions Charge
XTL	X-to-Liquids (X – biomass / biogas, MSW, other)
ZEV	Zero Emission Vehicle

9.2 DIESEL ASTM

Property	ASTM Test method	Grade No. 1-D	No. 2-D	No. 4-D
		S500	S500	
Flash point, °C, min	D93	38	52	55
Water and sediment, % vol, max	D2709	0.05	0.05	
	D1796			0.50
Distillation				
1. Physical distillation	D86			
Distillation temperature, °C 90%, % vol				
min			282	
max		288	338	
2. Simulated distillation	D2887			
Distillation temperature, °C 90%, % vol				
min			300	
max		304	356	
Kinematic viscosity, cSt at 40°C	D445			
min		1.3	1.9	5.5
max		2.4	4.1	24.0
Ash % mass, max	D482	0.01	0.01	0.10
Sulfur, ppm (μg/g) max	D5453			
% mass, max	D2622	0.05	0.05	
% mass, max	D129			2.00
Copper strip corrosion rating max 2 h at 50°C	D130	No. 3	No. 3	
Cetane number, min	D613	40	40	30
a. Cetane index, min	D976-80	40	40	
b. Aromaticity, % vol, max	D1319	35	35	
Operability requirements				
Cloud point, °C, max	D2500			
or				
LTFT/CFPP, °C, max	D4539/S6371			
RCR on 10% residue % mass, max	D524	0.15	0.35	
Lubricity, HFRR at 60°C micron max	D6079	520	520	

Note: For distillation, cetane number, and operability one of the two requirements shall be met.
Source: ASTM D975.

Figure 54 (a) Diesel No. 2 ASTM

Property	ASTM	Grade	
	Test method	No. 1-D	No. 2-D
		S500	S500
90% volume recovered, min			282 (540)
90% volume recovered, max		288 (550)	338 (60)
2. Simulated distillation, °C (°F)	D2887		
10% volume recovered, max		195 (380)	
90% volume recovered, min			300 (570)
90% volume recovered, max		304 (580)	356 (670)
Kinematic viscosity, cSt at 40°C (104°F)	D445		
Min		1.3	1.9
Max		2.1	3.4
Ramsbottom carbon residue, max (% mass on 10% distillation residue)	D524	0.15	0.35
Sulfur, % mass, max	D2622 D129	0.05 0.50	0.05 0.50
Copper strip corrosion rating, max, after 3 h at 50°C	D130	No. 3	No. 3
Density at 15°C, kg/m^3	D1298		
Min			
Max		850	876
Pour point, °C (°F), max	D97	−18 (0)	−6 (21)

Note: For distillation one of the two requirements shall be met.
Source: ASTM D396.

Figure 55 (b) Diesel No. 2 ASTM (continued)

9.3 KEY DEFINITIONS

Clarification as to the intended meaning of various terms is provided below:

- Additive(s): additives are present in most fuels irrespective of their area of use. As rule-of-thumb additives are found at levels <1% by mass or volume. There is no one type of additive(s), they are used to minimize or enhance a certain attribute of the fuel. Examples of additives are anti-oxidants, combustion aids, detergents, dyes, lubricity additives, pour point suppressants, and stabilizers etc.

- Blend-stock(s): as rule-of-thumb blend-stocks are generally found at levels greater than five percent (>5%) and approaching 20%. In the public domain it is often the case that products such as ethanol, methanol, synthetic kerosene and similar are referred to as ‘fuel’ when strictly speaking they are not a fuel, but a fuel-component or blend-stock. It is important to recognize that most fungible fuels are a blend of various components where they are produced to an industry standard and specification.

- Distillate Fuel Oil[98]
  - *'A general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as No. 1, No. 2, and No. 4 fuel oils are used primarily for space heating and electric power generation.'*

- Fuel(s): the term fuel is used inter-changeably in the report to refer to blend-stock, fuel component or fungible fuel. The context in which the terms are used define their intended meaning.

9.4 NOMENCLATURE

Nontechnical and technical information referenced in the study may originate from different sources; variations in use and intended meaning of terminology is possible. Where possible and without distraction to the original sources' intent, we have tried to limit this. Where misunderstanding may have unintentionally been created – possible reasons for this may be one or more of the following:

- Context: this may be a result of context in which the word / phrase has been used or where information has been quoted from technical or nontechnical sources such as business, company, sales documents or other. At time of writing, it may not have been possible to determine the references intended meaning of the word / phrase / information.

- Time: the word / term / definition originates from a paper / document that can be considered scientifically dated; the [continued] use of the dated information is deemed relevant to the context in which it has been applied.

9.5 TECHNICAL AND COMMERCIAL READINESS LEVEL

Commercial Readiness Level (CRL) is used to complement Technology Readiness Level (TRL) for the reason the latter does not adequately describe nor provide suggestion to a product or technologies 'market readiness or acceptability'.

[98] Definition from US Energy Information Administration.

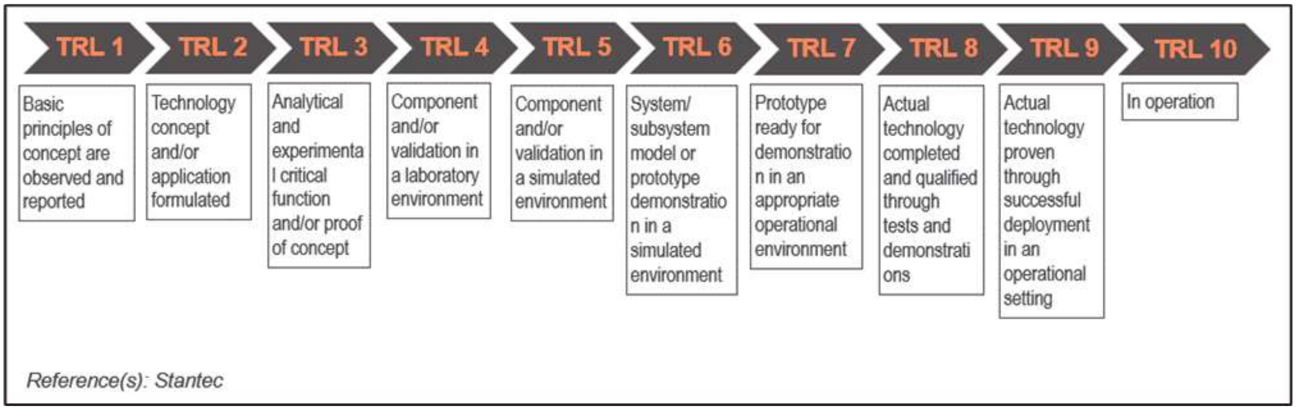


Figure 56 Technology Readiness Level (TRL)

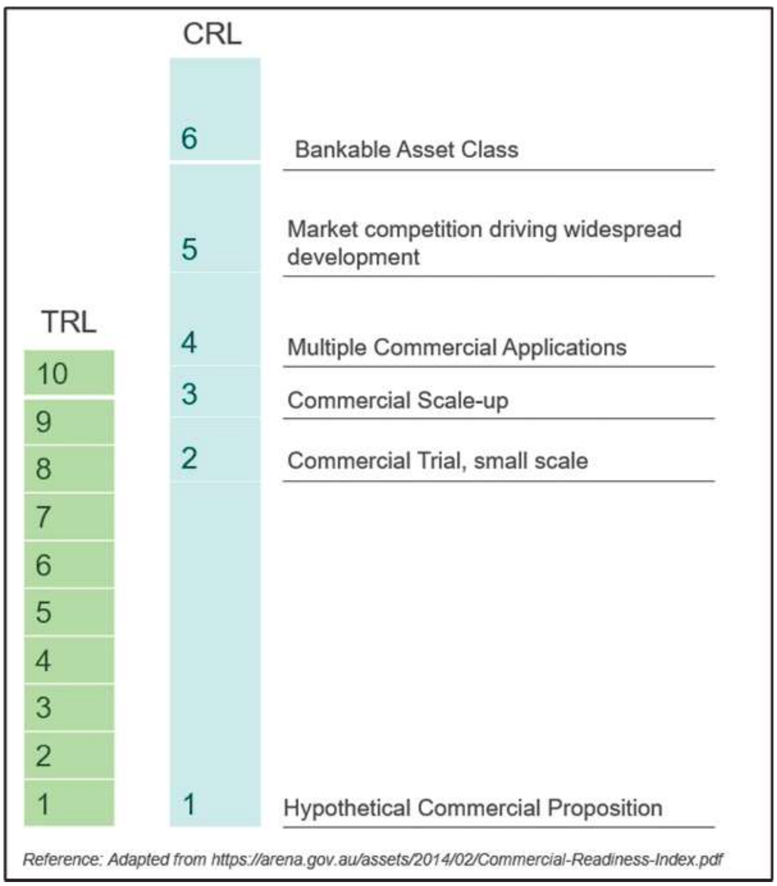


Figure 57 Commercial Readiness Level (CRL)

Using fuels like diesel, gasoline and others as an example, the technology to produce a fully-fledged fuel or blend component may already exist, but the market for various reasons such as regulation, Original Equipment Manufacturers (OEM) approvals and product certification, etc. may not be ready, able, or willing to accept it. For this reason, CRL and TRL where referenced are divided into two parts - the first provides a perspective on the CRL and TRL from a Production perspective and the second from a Market [use] perspective.

9.6 REPORT METHODOLOGY

Information gathered during the project were obtained from publicly available primary and secondary sources as well as Stantec internal information and experience from prior and similar projects, Table 50.

No	Data Type	Source
1	Primary Data Sources	· City Municipal, County, Provincial, Federal open databases
		· Company information
		- Website
		- Marketing documents
		- News releases
		- Financial Analyst reports
		- Roadshow presentations
		- Safety data sheets (SDS) / Technical data sheets (TDS)
		· Industry and research peer reviewed journals / articles
		· Interviews
		· Research Articles
2	Secondary Data Sources	· Industry associations e.g.: Canadian Plastics Industry Association; Provincial Recycling Councils
		· General News
		· Industry publications: e.g. Composites World
		· Such information that can be accessed as samples

Table 50 Primary and Secondary Data Sources

9.7 TEST METHODS – DIESEL STABILITY

TABLE 1: Comparison of commonly used oxidative stability measurement techniques.

	EN 14112 & EN 15751 (Rancimat)	PetroOxy (ASTM D7545)	ASTM D2274 and EN ISO 12205	ASTM D5304	ASTM D4625
Applicability	Europe	USA	USA (D2274) and Europe (EN ISO 12205)	USA	USA
Fuels	Stability of FAME and FAME-containing blends	Determining the stability of diesel fuels from B0 to B100	Determining the inherent oxidation stability of a middle distillate	Assessing the potential long term storage stability of diesel	Determining the inherent storage stability of middle distillates
Limit	8 hours for neat FAME in Europe, 3 hours in the USA	No limits specified under ASTM	25 mg/100 mL in Europe	No limits specified	No specified limits: fuel should be stable for this period
Sample volume	3 mL for neat FAME and 7.5 mL for FAME/diesel blends	5 mL	350 mL	100 mL	400 mL/time measured
Temperature (°C)	110	140	95	90	43
Pressure	Ambient	700 kPa Oxygen	Ambient	800 kPa oxygen	Atmospheric pressure
Flow	10 L/min air	No flow	3 L/h oxygen bubbling	No flow	Atmospheric-no flow
Time	Determined by the stability of the fuel	Determined by the stability of the fuel	16 h	16 h	1 week roughly simulates 1 month of storage under normal conditions. Test carried out over 24 weeks, which is equivalent to two years
Measurement	Conductivity	Pressure decrease	Adherent insolubles and filterable insolubles: total insolubles	Total Insolubles	Adherent insolubles and filterable insolubles: total insoluble material
Applicability (advantages/ Disadvantages)	Long analysis time for low FAME blends, time-consuming sample preparation	Rapid method, highly accelerated so not fully representative of actual stability	Short test, not fully representative of actual aging potential (comparative)	Short test, not fully representative of actual aging potential (comparative)	Long term storage potential, close to real life conditions but very slow

Figure 58 Commonly Used Stability Measurement Techniques for Diesel[99]

[99] A Comparison of the Stability Performance of Blends of Paraffinic Diesel and Petroleum-Derived Diesel, with RME Biodiesel Using Laboratory Stability Measurement Techniques. S. de Goede et al. Sasol Southern Africa Energy, Energy Technology, Sasolburg 1947, South Africa. 23rd January 2015. Hindawi Publishing Corporation Journal of Fuels. Volume 2015, Article ID 528497, 15 pages. http://dx.doi.org/10.1155/2015/528497

Appendix C, Attachment 5

Impact of Prolonged Loss of LIL on Island Reservoir Levels

Hatch Ltd.

July 2, 2024

HATCH

Nalcor Energy Island Hydro Winter Firm Energy Analysis H373064	Engineering Report Engineering Management Impact of Prolonged Loss of LIL on Island Reservoir Levels

Report

Impact of Prolonged Loss of LIL on Island Reservoir Levels

H373064-0000-200-230-0001

2024-07-02	0	Final	Project Team	T. Olason	T. Olason
DATE	**REV.**	**STATUS**	**PREPARED BY**	**CHECKED BY**	**APPROVED BY**
				Discipline Lead	**Functional Manager**

Table of Contents

1. Introduction **1**

1.1 Scope 1
1.2 Methodology 1
1.3 Summary of Findings 2

2. Results for Existing System Configuration **4**

2.1 January Outage 4
2.1.1 Generation Impact 4
2.1.2 Impact on Reservoirs 5
2.2 March Outage 10
2.2.1 Generation Impact 10
2.2.2 Impact on Reservoirs 12

3. Results for 2032 System Configuration **17**

3.1 January Outage 17
3.1.1 Generation Impact 17
3.1.2 Impact on Reservoirs 18
3.2 March Outage 23
3.2.1 Generation Impact 24
3.2.2 Reservoir Impact 25

4. Conclusions and Recommendations **29**

List of Tables

Table 1-1: Generation Increases in Response to LIL Outage 2
Table 2-1: Average Additional Storage Drawdown due to January 2025 Outage 6
Table 2-2: Additional Storage Change March 2025 Outage 12
Table 3-1: Additional Storage Change due to January 2032 Outage 19
Table 3-2: Additional Storage Change March 2032 Outage 25

List of Figures

Figure 2-1: Island Imports for Reference Case and January 2025 Outage 4
Figure 2-2: Hydro Generation for Reference and January Outage 5
Figure 2-3: Thermal Generation for Reference and January Outage 5
Figure 2-4: Bay d'Espoir Reservoir Storage Change for January Outage Period 7
Figure 2-5: Cat Arm and Hinds Lake Storage Change for January Outage Period 8
Figure 2-6: Bay d'Espoir Storage Change for Reference and January Outage 9
Figure 2-7: Cat Arm Storage Change for Reference and January Outage 9
Figure 2-8: Hinds Lake Storage Change for Reference and January Outage 10
Figure 2-9: Island Imports for March 11
Figure 2-10: Hydro Generation for Reference and March Outage 11
Figure 2-11: Thermal Generation for Reference and March Outage 12

Figure 2-12: Storage Changes for March Outage Period ... 13
Figure 2-13: Storage Changes for Cat Arm and Hinds Lake ... 14
Figure 2-14: Bay d'Espoir Storage Changes – March Outage ... 15
Figure 2-15: Cat Arm Storage Changes – March Outage ... 16
Figure 2-16: Hinds Lake Storage Changes – March Outage ... 16
Figure 3-1: Island Imports 2032 ... 17
Figure 3-2: Hydro Generation 2032 ... 18
Figure 3-3: Thermal Generation for 2032 ... 18
Figure 3-4: Bay d'Espoir Storage Changes for January 2032 Outage Period ... 20
Figure 3-5: Cat Arm and Hinds Lake Storage Changes for January Outage Period ... 21
Figure 3-6: Bay d'Espoir Storage Change Comparison – January Outage Period ... 22
Figure 3-7: Hinds Lake Storage Change Comparison – January Outage ... 22
Figure 3-8: Cat Arm Storage Change Comparison – January Outage ... 23
Figure 3-9: Island Imports March 2032 ... 23
Figure 3-10: Hydro Generation for Reference and March 2032 ... 24
Figure 3-11: Thermal Generation for Reference and March Outage ... 24
Figure 3-12: Bay d'Espoir Storage Changes for March 2032 Outage Period ... 26
Figure 3-13: Cat Arm and Hinds Lake Storage Changes for March Outage Period ... 27
Figure 3-14: Bay d'Espoir Storage Change – March Outage ... 28
Figure 3-15: Cat Arm Storage Changes – March Outage ... 28
Figure 3-16: Hinds Lake Storage Change – March Outage ... 29

1. Introduction

The purpose of this study was to assess the impact of an unexpected 6-wk outage on the Labrador Island Link (LIL) on the Island Interconnected system. The outage impact on hydro generation and the effects on reservoir levels are of particular interest.

1.1 Scope

A prolonged outage of the LIL is most likely to occur in winter due to extreme weather conditions. The impact of a long LIL outage is also going to be greatest in the winter period when the load is high, and reservoirs are at the lowest level. Therefore, a 6-wk outage starting at the beginning of January and another in early March were selected for this study. The analysis was conducted with the current 2024 system composition and a future 2032 system. The system composition in 2032 included the addition of Bay d'Espoir Unit 8, additional 150-MW combustion turbine, 300 MW of additional wind generation and no Holyrood thermal generation system. All generation resources were assumed to be available at full capacity during the LIL outages.

1.2 Methodology

The Vista DSS™ has been implemented for the integrated Newfoundland and Labrador Hydro (NLH) system and used for numerous studies, as well as operationally. The system representation includes all hydro, thermal and renewable generation on the island and Labrador and the transmission network including the Maritime Link (ML) and the LIL. The setup also includes the Nova Scotia Block and market opportunities in Nova Scotia and New England.

Under normal system conditions, the amount of energy that can flow over the LIL to the island is limited by the interdependencies with the ML and Island load. This interdependence exists because both high-voltage direct current links must work together using special protection systems that will suddenly reduce their power flows (runbacks) in order to transiently regulate system frequency in the event a contingency occurs on the other high-voltage direct current link. This transmission relationship was incorporated into Vista for this study.

The LT Vista module was deployed to simulate operations using a range of historic inflows from 1958 to 2023. The analysis horizon for the current system composition started in January 2024 and ended July 2027, with the unexpected outages occurring in January and March 2025. Simulation for future system configuration, started in January 2031 and ended in July 2035, with the outages occurring in January and March 2032.

Optimization models, such as the Vista DSS™, solve the hydro scheduling problem simultaneously in time and space. Linear and or piecewise linear approximations of all the equations needed to describe the problem are solved using linear programming solvers. While this approach ensures an optimal answer, the solver has foresight because it is solving for the whole-time horizon and not one time step at a time. This is usually not an issue, since the scheduling problem is driven by load demand, there is limited ability to store water, conveyance limitation and constraints. However, to accurately capture the impact of an unforeseen forced outage, the analysis was conducted such that the model could not try to prepare in advance for the forced outages. A simulation was done without the forced LIL outages to establish a reference scenario. The reference schedule up to the timing of the outage was then imposed for the outage scenarios. This ensured that the simulations were as realistic as possible, and after the outage had occurred, the model could optimize the response to the event, that is, increase hydro and thermal generation in an optimal manner, subject to the constraints and limitations of the system.

Note that contractually, NLH does not have to supply the Nova Scotia Block during a forced outage of the LIL and the Nova Scotia Block was set to zero during the outage.

1.3 Summary of Findings

Simulations of the NLH system operations indicate that the January to March average imports from Labrador through the LIL to the island of 308 MW for the existing 2024 system. In 2032, the imports are expected to average around 320 MW for the same period.

Results from the outage case simulations indicate that the system has adequate reservoir storage to make up for the loss of imports by increasing hydro and thermal generation to maintain reservoir storage through the winter period. The average generation increase needed for the different scenarios is summarized in Table 1-1.

Table 1-1: Generation Increases in Response to LIL Outage

Scenario	Hydro (MW)	Percent Change	Thermal (MW)	Percent Change
January 2025	76	9	259	357
March 2025	117	16	181	241
January 2032	129	17	149	N/A*
March 2032	159	23	77	N/A*

*There was no thermal generation in the reference simulation

In January the system is early in the winter drawdown and the modeling simulation indicate that a stronger thermal response is prudent, to maintain sufficient reservoir storage for later in the season. The 6-wk March outage extends into April and often the spring runoff is starting or about to start and a stronger hydro response is possible, depending on the timing of the spring runoff.

The assumed 2032 system composition has Unit 8 at Bay d'Espoir and 300 MW of additional wind generation, as well as a new 150-MW combustion turbine. No thermal generation was needed in the 2032 reference case, however, thermal generation was required in both January and March outage cases. The same pattern of a higher hydro response in the March outage compared to the January outage is evident in the 2032 outage case as it was in the

2025 case. Simulations indicate that during the January outages, capacity during highest peak periods might be tight and should be examined further.

2. Results for Existing System Configuration

2.1 January Outage

To assess the impact and system response to the forced LIL outage, simulations were carried out with no forced outage "Reference Case" and then repeated with a 6-wk unplanned LIL outage starting in the first week of January 2025.

2.1.1 Generation Impact

The amount of generation sunk to the island is calculated as the difference between LIL and flow into the NLH to Bottom Brook tie-line. The difference between the average line flows is illustrated in Figure 2-1 for the two cases.

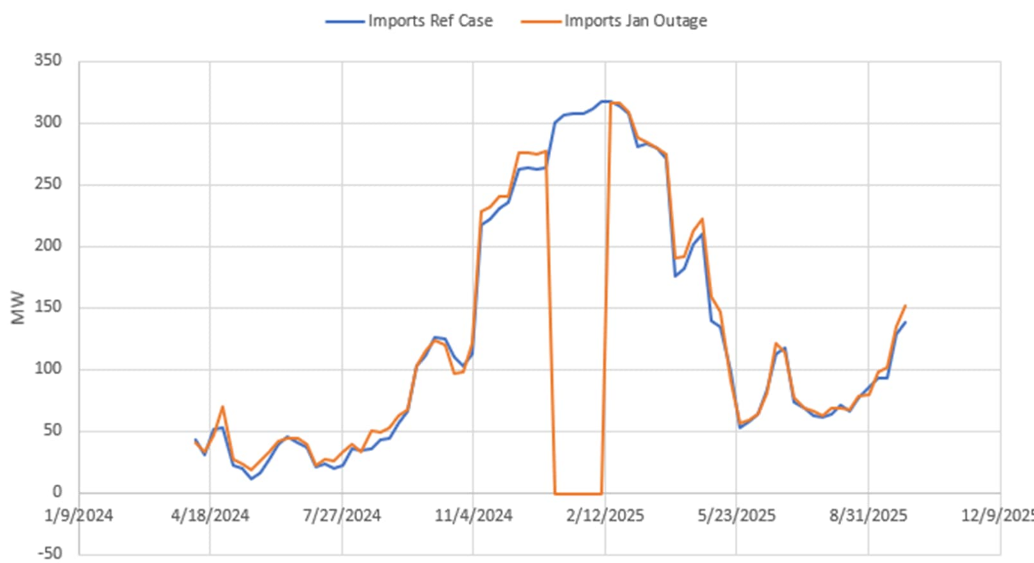


Figure 2-1: Island Imports for Reference Case and January 2025 Outage

Based on the simulations and using the method outlined above, about 308 MW on average are imported to the island in January. To respond to the outage, NLH can increase hydro and/or thermal generation and the Emera Block was set to zero during the outage, as discussed earlier. The island hydro generation for reference and outage simulations are illustrated in Figure 2-2.

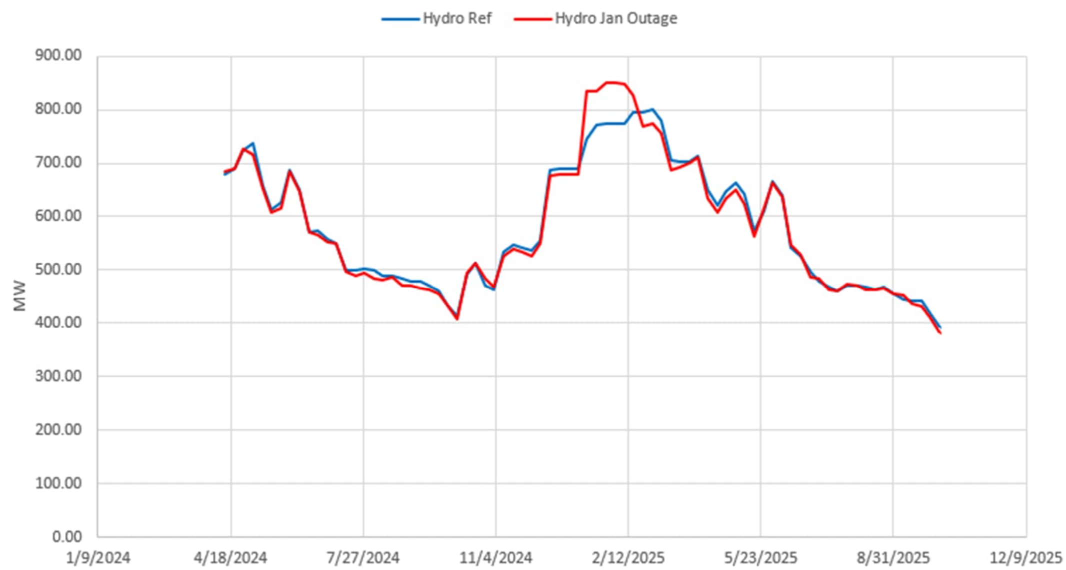


Figure 2-2: Hydro Generation for Reference and January Outage

The thermal generation for reference and the January outage cases are illustrated in Figure 2-3.

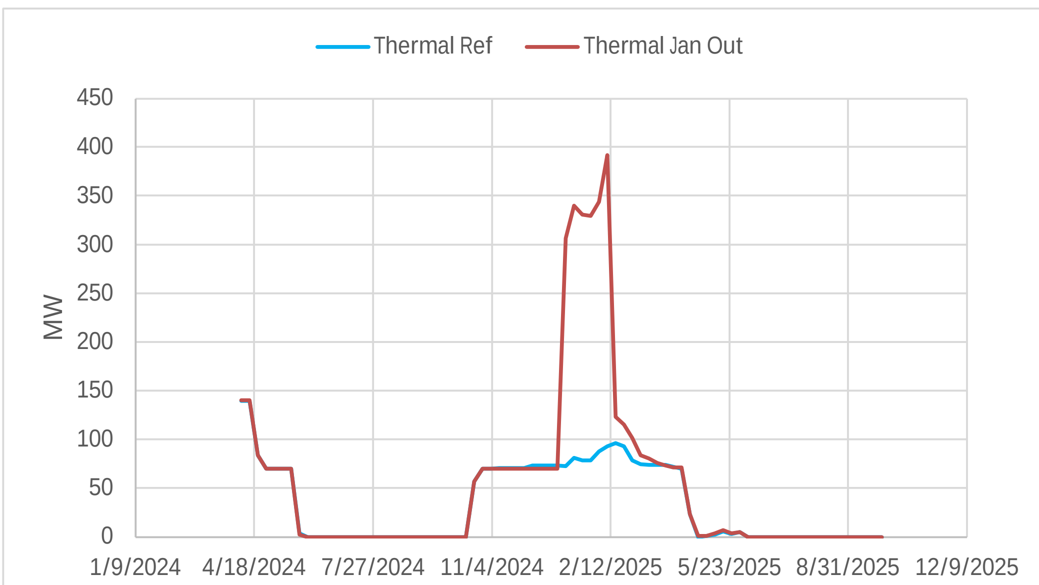


Figure 2-3: Thermal Generation for Reference and January Outage

2.1.2 Impact on Reservoirs

The increase in hydro generation in response to the LIL outage depends on the state of the reservoir at the beginning of the outage, and on inflows. These vary considerably for the range of hydrologies. The increased hydro generation results in additional drawdown on reservoirs, beyond what was needed in reference case. During the winter period, reservoirs are generally in a drawdown mode, but rainfall and/or snowmelt events can occur in winter. The simulations reflect this. The average additional storage changes from the beginning of the outage to the end of the outage, that is the delta between reference and January outage simulations, are summarized in Table 2-1.

Table 2-1: Average Additional Storage Drawdown due to January 2025 Outage

Reservoir	Additional Storage Change (MCM)
Victoria	-26
Meelpeg	-27
Long Pond	-74
Cat Arm	-21
Hinds Lake	-24

Annual storage change for each year of historic inflows (1958 to 2023) are shown for the Jan outage period for both reference and January outage period in Figure 2-4 and Figure 2-5 to demonstrate the variability from year to year.

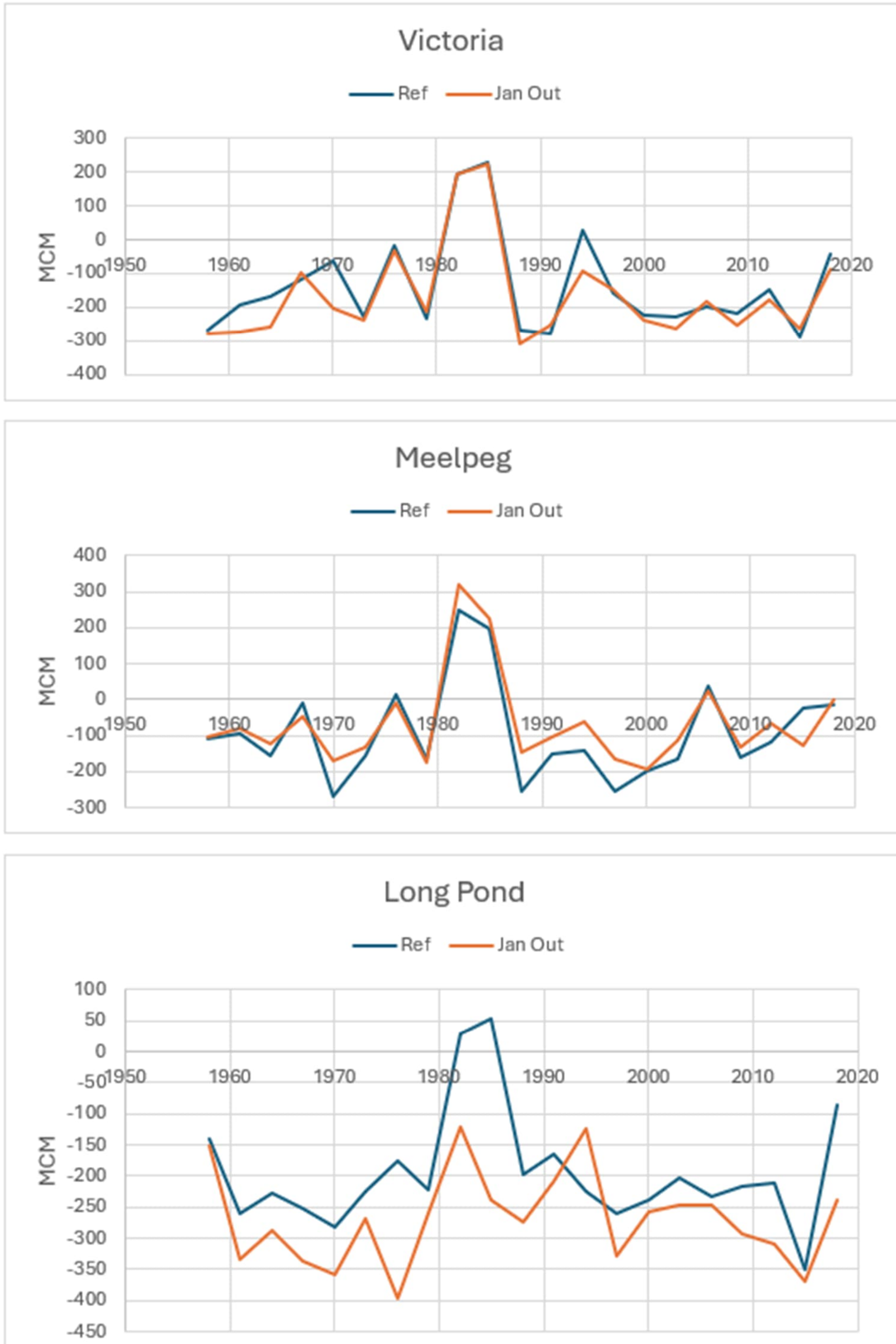


Figure 2-4: Bay d'Espoir Reservoir Storage Change for January Outage Period

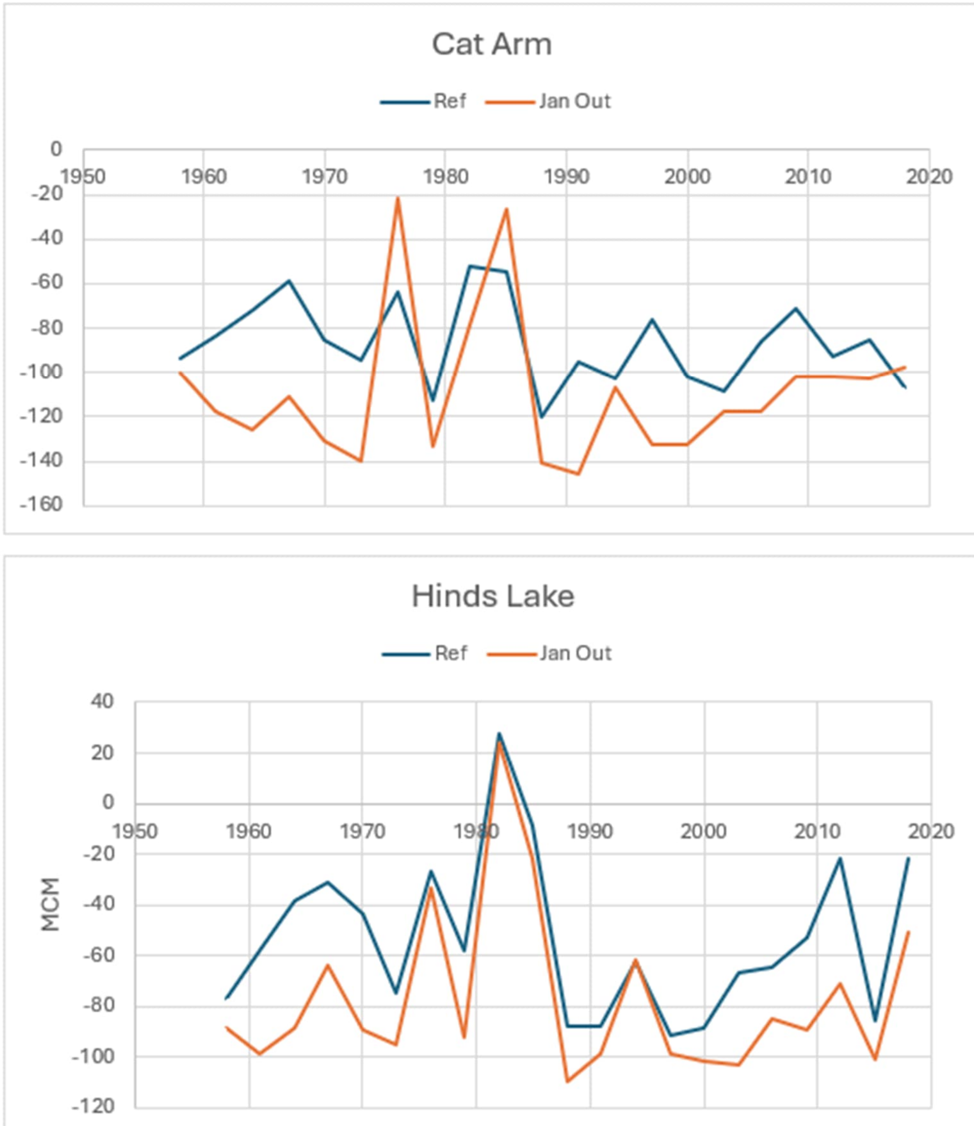


Figure 2-5: Cat Arm and Hinds Lake Storage Change for January Outage Period

Average storage change trajectories for the major hydro system from just before to after outage are illustrated in Figure 2-6 to Figure 2-8. With the outage occurring in early winter, the reservoirs take a while to recover due to high load demand and low inflows. As noted earlier, the simulations covered the period from January 2024 to July 2027 and the levels extracted for early 2025 varied a little from one simulation to another. Reservoir levels at the beginning of outages were not forced to be the same as in the reference simulation.

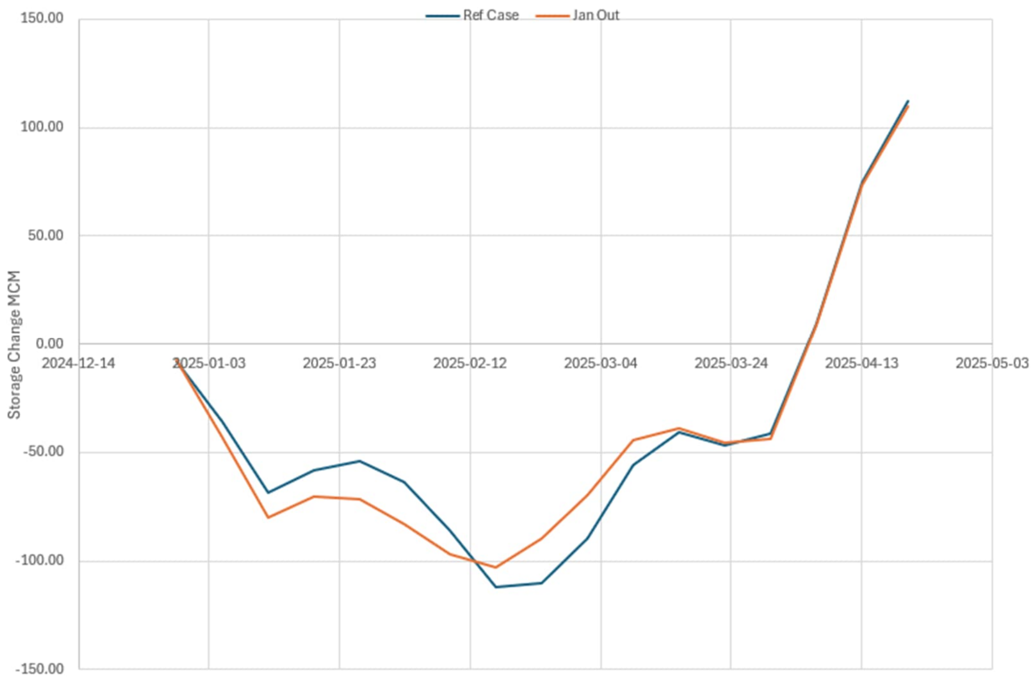


Figure 2-6: Bay d'Espoir Storage Change for Reference and January Outage

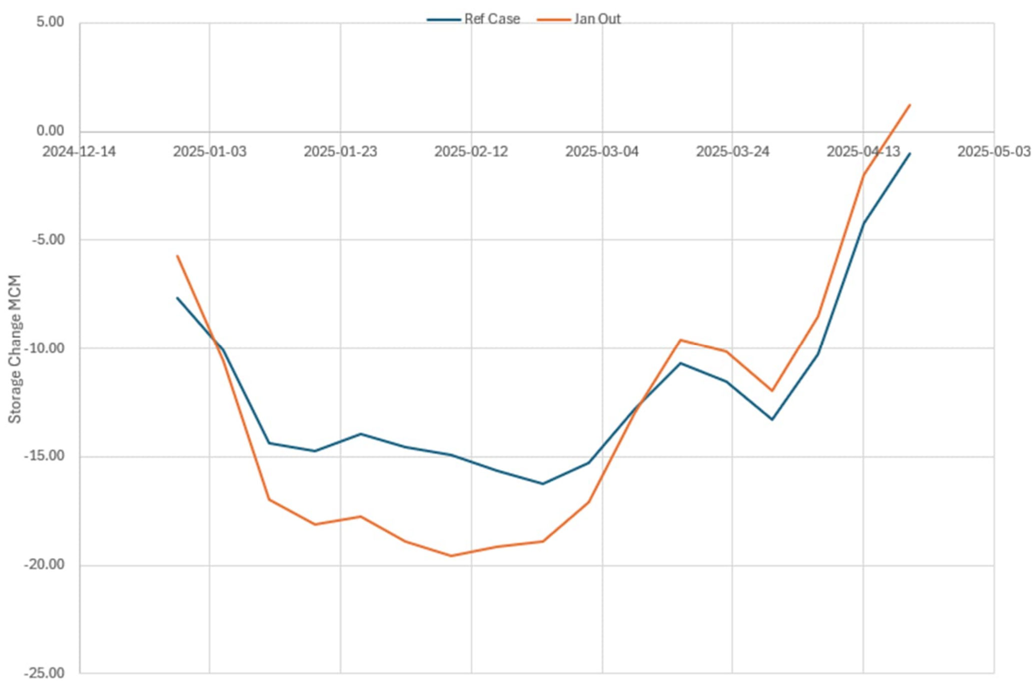


Figure 2-7: Cat Arm Storage Change for Reference and January Outage

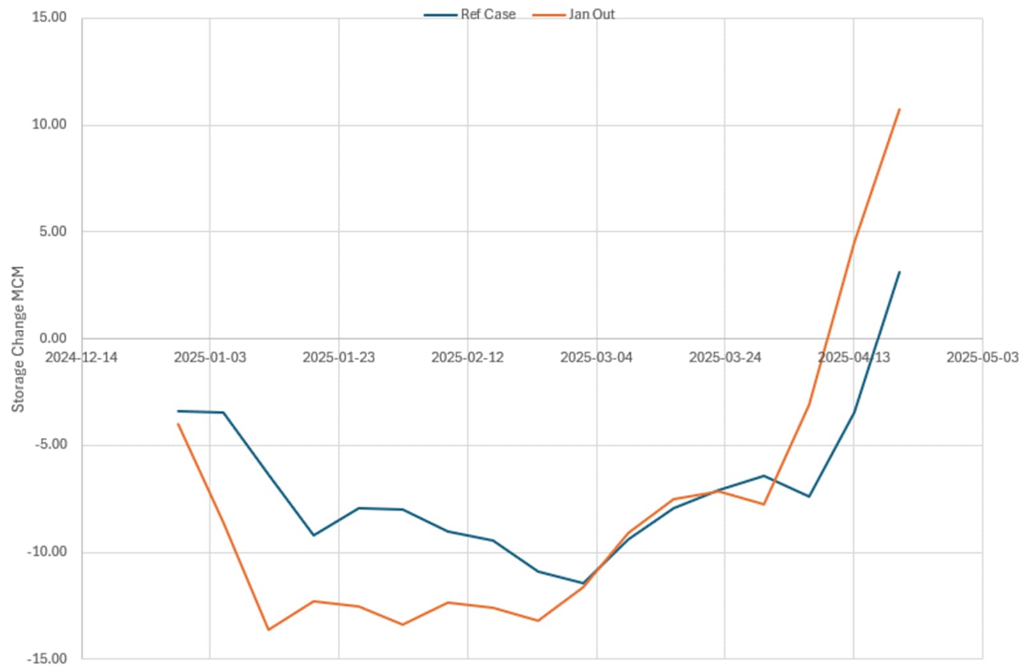


Figure 2-8: Hinds Lake Storage Change for Reference and January Outage

2.2 March Outage

The simulation for the January 2024 to July 2027 were repeated with a forced LIL outage starting in the first week of March 2025.

2.2.1 Generation Impact

The amount of generation brought to the island is the difference between LIL and ML line flow and the difference between average line flows are illustrated in Figure 2-9 for the two cases.

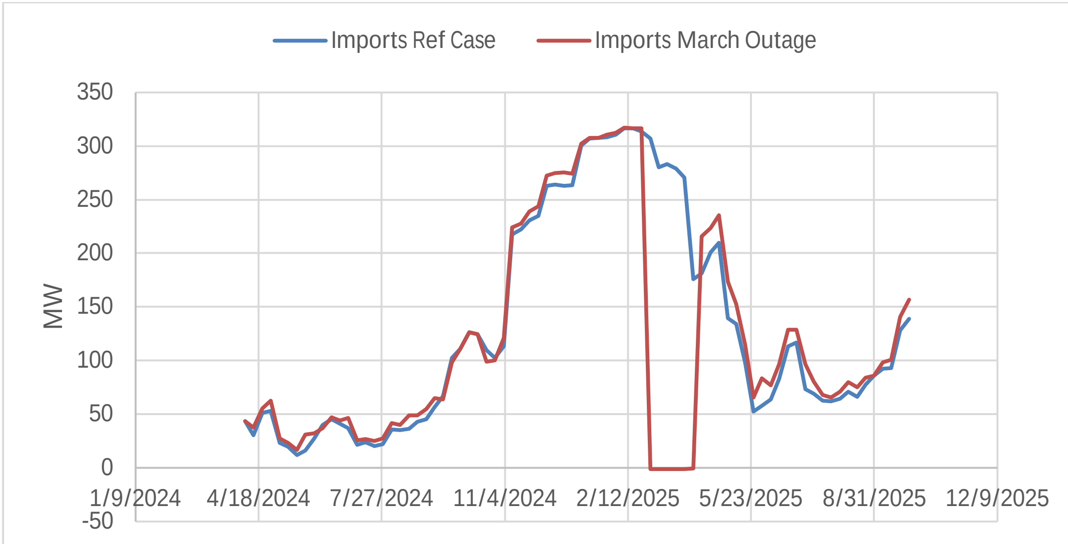


Figure 2-9: Island Imports for March

Simulations indicate that the imports from Labrador under the Reference case reduce from an average of 308 MW during the January outage period to 266 MW during the March outage period. The island hydro generation for the reference and March outage simulations are illustrated in Figure 2-10.

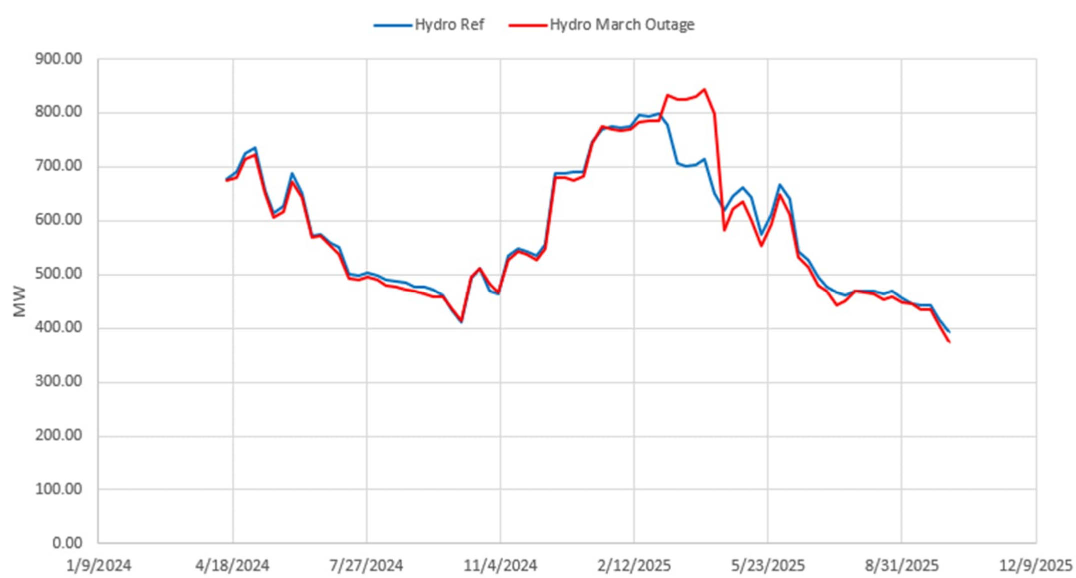


Figure 2-10: Hydro Generation for Reference and March Outage

The thermal generation for the reference and March outage simulations are illustrated in Figure 2-11.

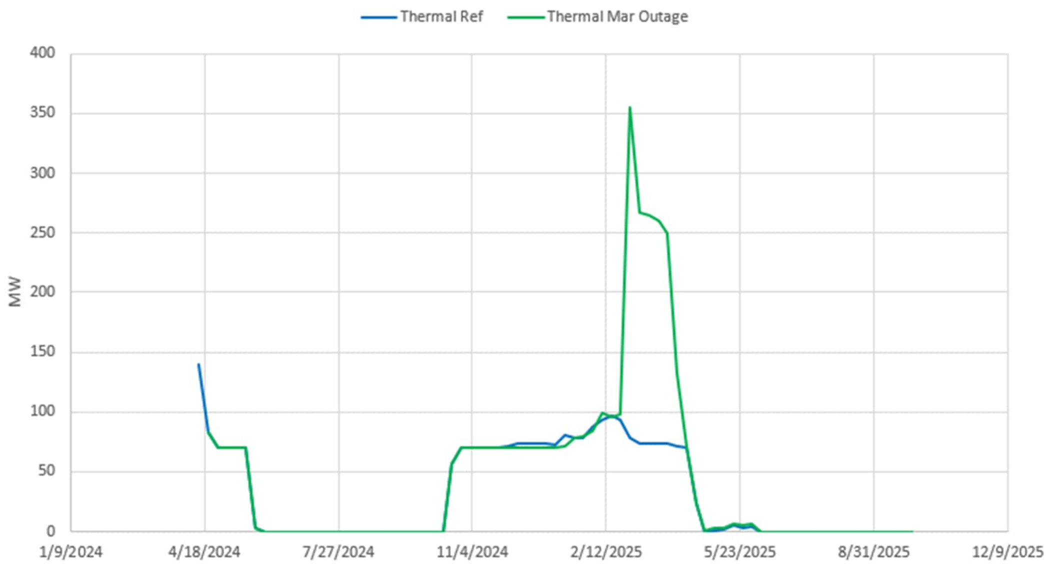


Figure 2-11: Thermal Generation for Reference and March Outage

2.2.2 *Impact on Reservoirs*

The hydro response to the LIL outage results in additional draw on reservoir storage. The average change in storage change beyond the change in the reference case from beginning to end of outage are summarized in Table 2-2.

Table 2-2: Additional Storage Change March 2025 Outage

Reservoir	Additional Storage Change (MCM)
Victoria	-38
Meelpeg	-15
Long Pond	-136
Cat Arm	-19
Hinds Lake	-17

Annual storage change for each year of historic inflows (1958 to 2023) are shown for the March outage period in Figure 2-12 and Figure 2-13 to demonstrate the variability from year to year.

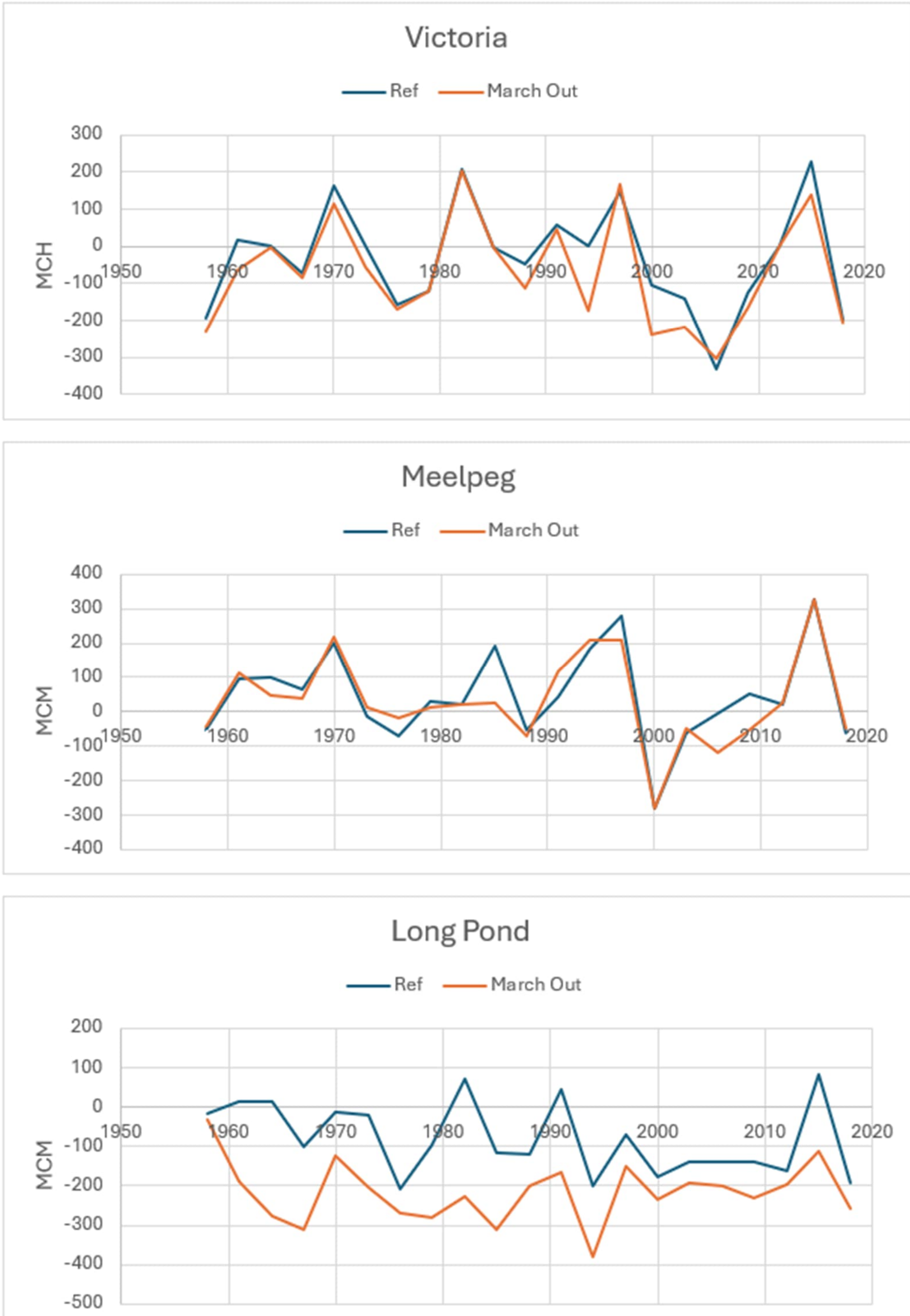
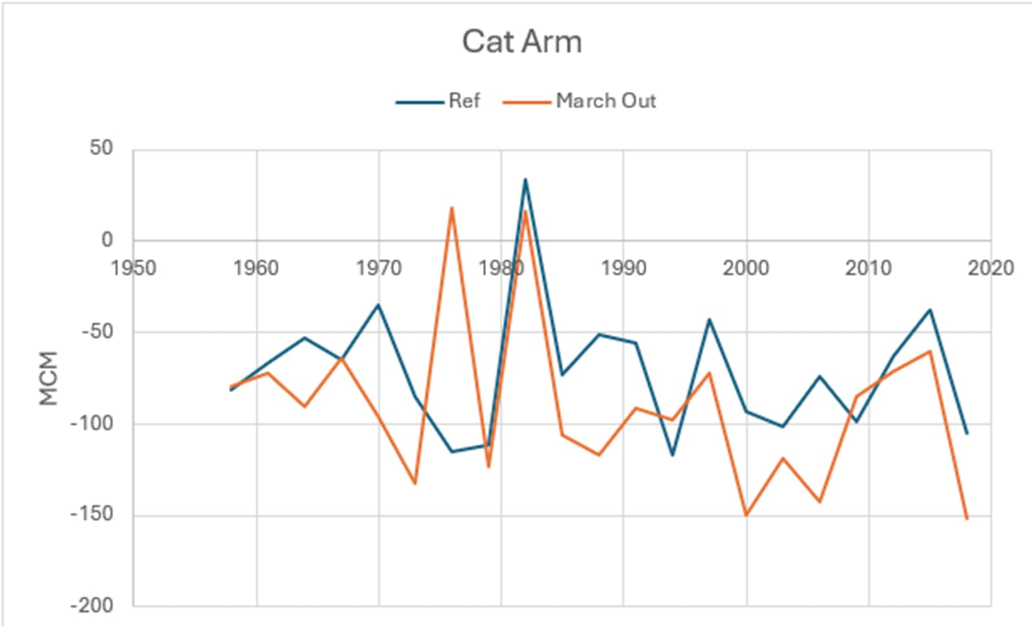


Figure 2-12: Storage Changes for March Outage Period



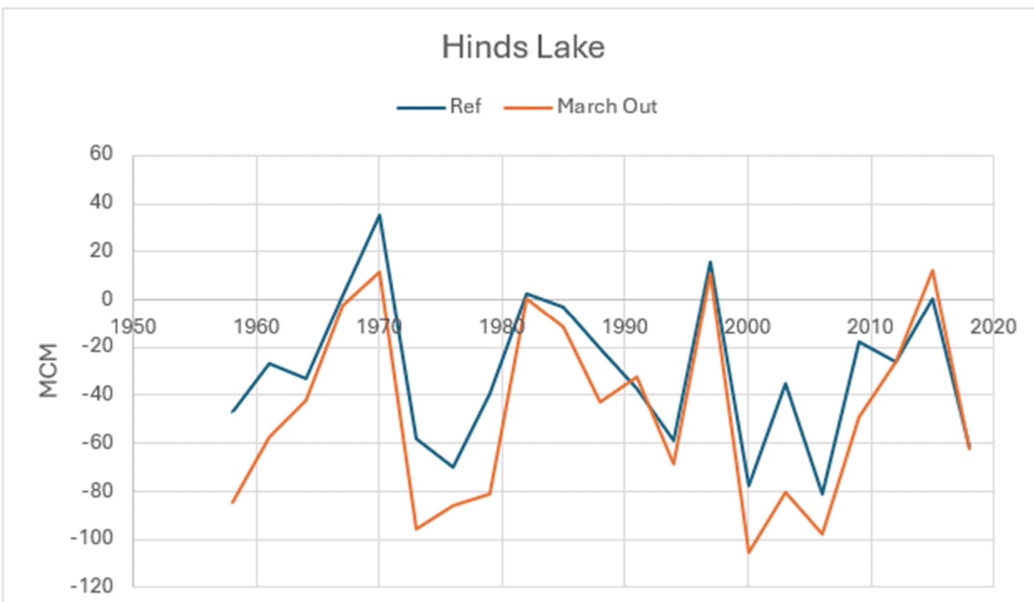


Figure 2-13: Storage Changes for Cat Arm and Hinds Lake

Average storage change trajectories for the major river systems from start of the year to just after are illustrated in Figure 2-14 to Figure 2-16. Note that in the outage simulation, total hydro generation up to the start of outage was forced to be the same as in the reference case, but reservoir levels were not. Therefore, for some reservoirs there are differences in the start of outage levels between reference and outage simulations.

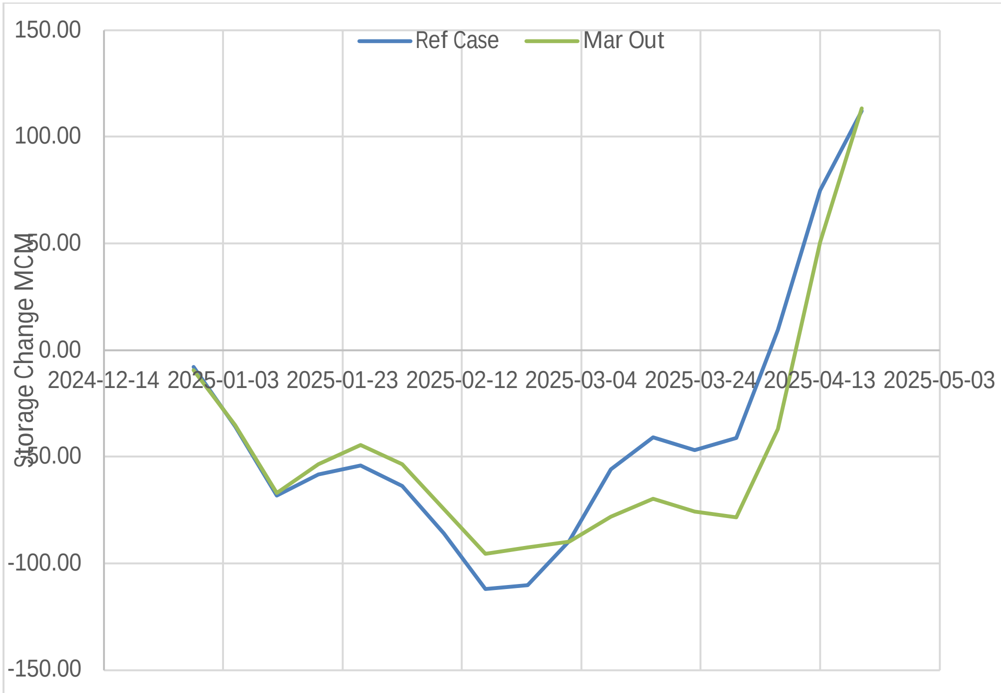


Figure 2-14: Bay d'Espoir Storage Changes – March Outage

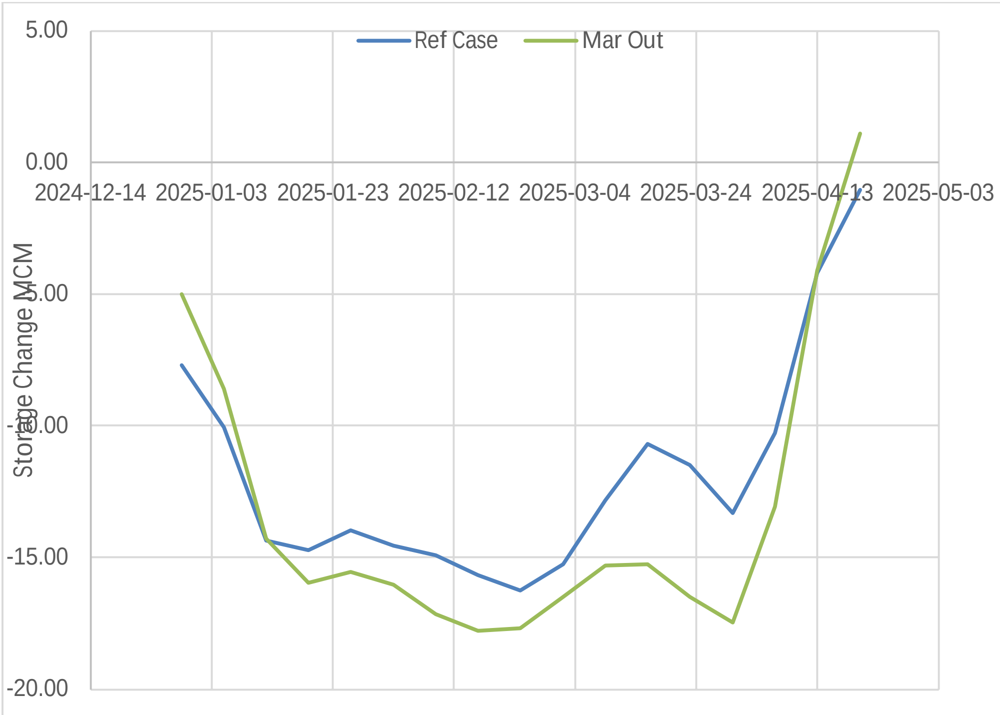


Figure 2-15: Cat Arm Storage Changes – March Outage

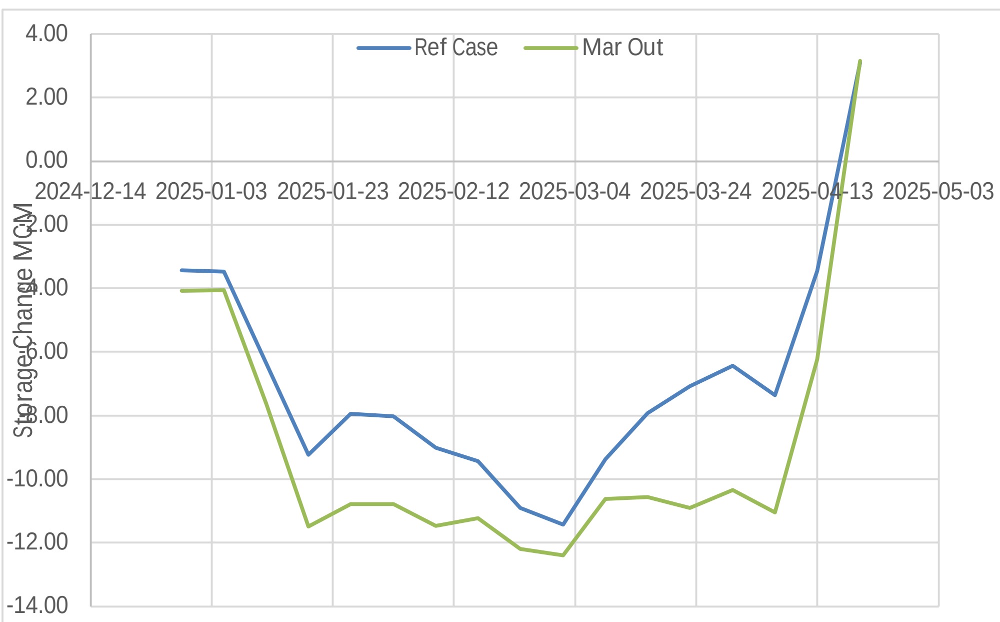


Figure 2-16: Hinds Lake Storage Changes – March Outage

3. Results for 2032 System Configuration

The analyses were repeated for expected system configuration in 2032, which included a Unit 8 at Bay d'Espoir, 300 MW of additional wind generation and an additional 150-MW combustion turbine.

3.1 January Outage

The simulations included a forced 6-wk outage starting in the first week of January 2032 and a reference case with no outage occurring.

3.1.1 Generation Impact

The amount of generation brought to the island is the difference between LIL and MIL line flow and the difference between average line flows, as illustrated in Figure 3-1 for the reference and outage cases.

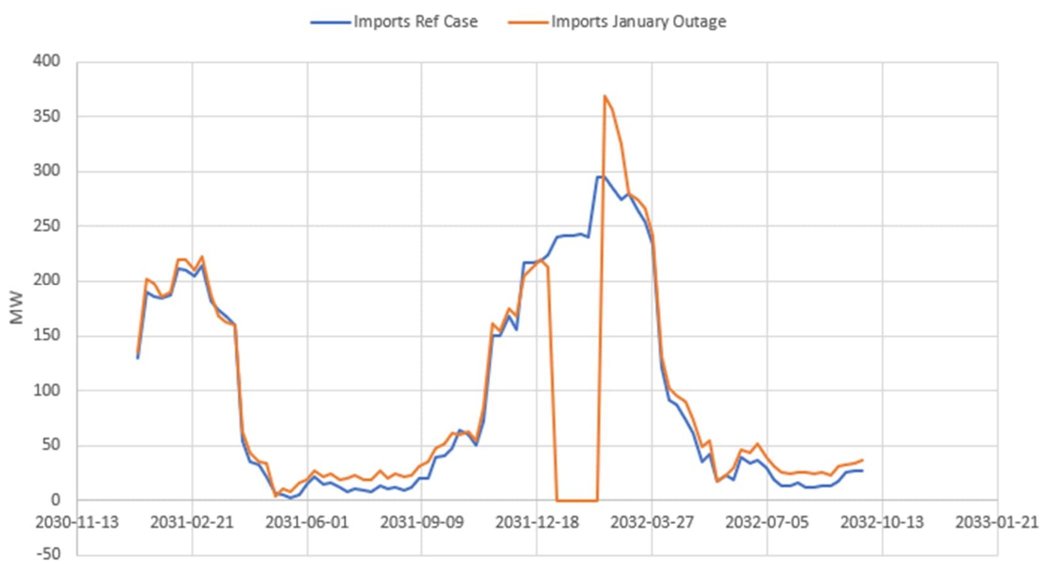


Figure 3-1: Island Imports 2032

Based on the simulations, about 240 MW are imported to the island over the six-week period starting in January, and to respond to the outage, NLH can increase hydro and/or thermal generation from combustion turbines and the Emera Block sales were set to zero during outage, as discussed earlier.

The island hydro generation for 2032 reference and outage simulations are illustrated in Figure 3-2.

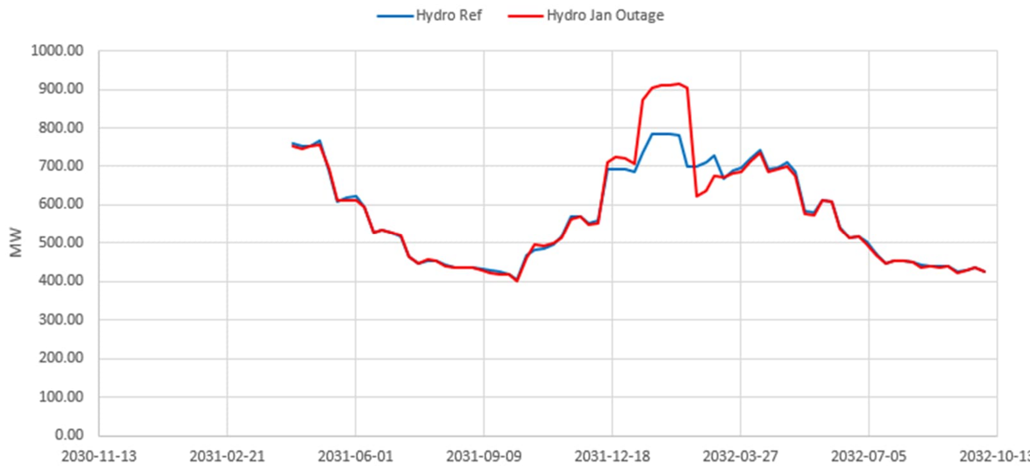


Figure 3-2: Hydro Generation 2032

The thermal generation for the reference and January outage simulations are shown in Figure 3-3.

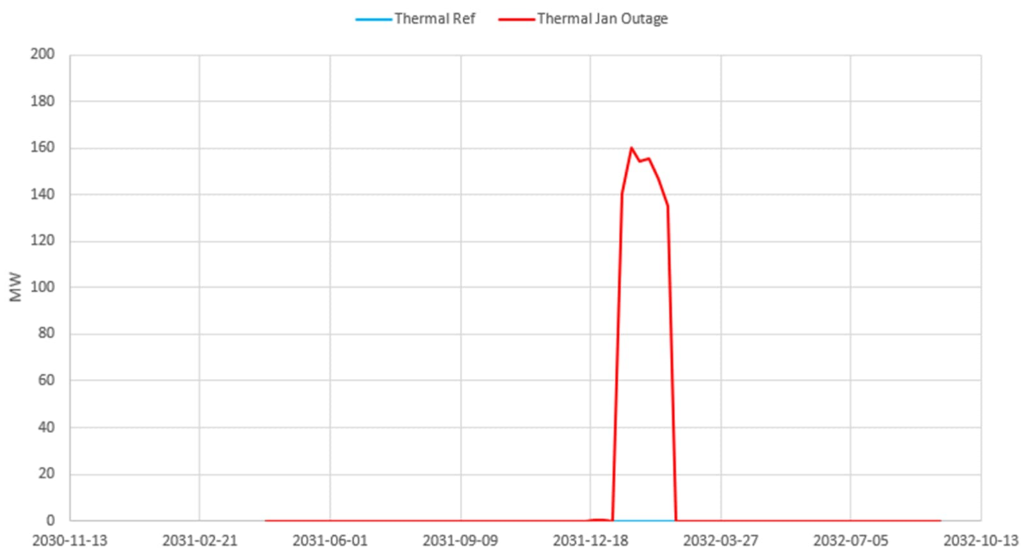


Figure 3-3: Thermal Generation for 2032

In response to the outage, the thermals contribute about 150 MW and hydro around 130 MW on average over the six-week period.

3.1.2 Impact on Reservoirs

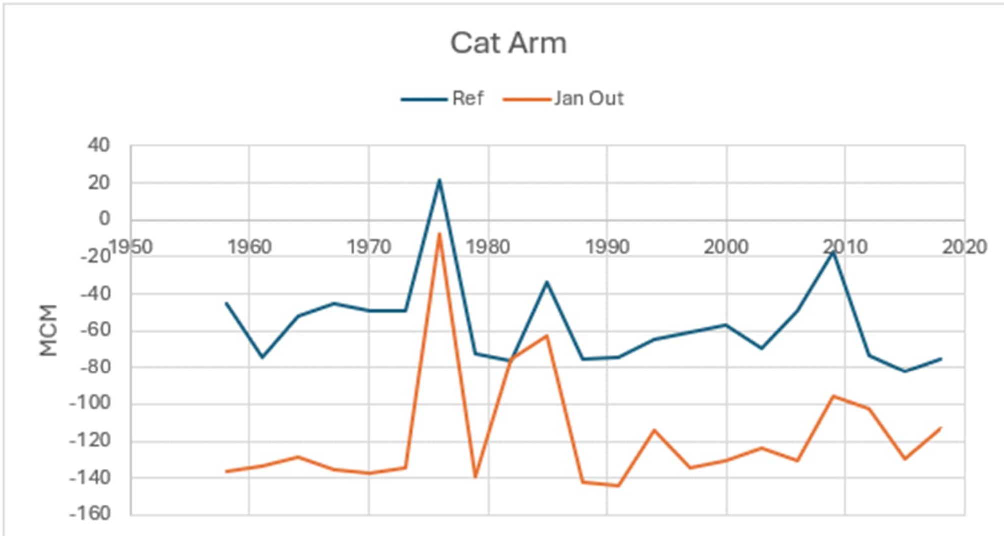
The additional draw on reservoir storage for the January 2032 outage, over and above the drawdown that occurred in the Reference Case, are shown in Table 3-1.

Table 3-1: Additional Storage Change due to January 2032 Outage

Reservoir	Additional Storage Change (MCM)
Victoria	-49
Meelpeg	-31
Long Pond	-95
Cat Arm	-60
Hinds Lake	-35

Annual storage change for each year of historic inflows (1958 to 2023) are shown for the January outage period for both reference and the outage simulations in Figure 3-4 and Figure 3-5 to demonstrate the variability from year to year.

Figure 3-4: Bay d'Espoir Storage Changes for January 2032 Outage Period



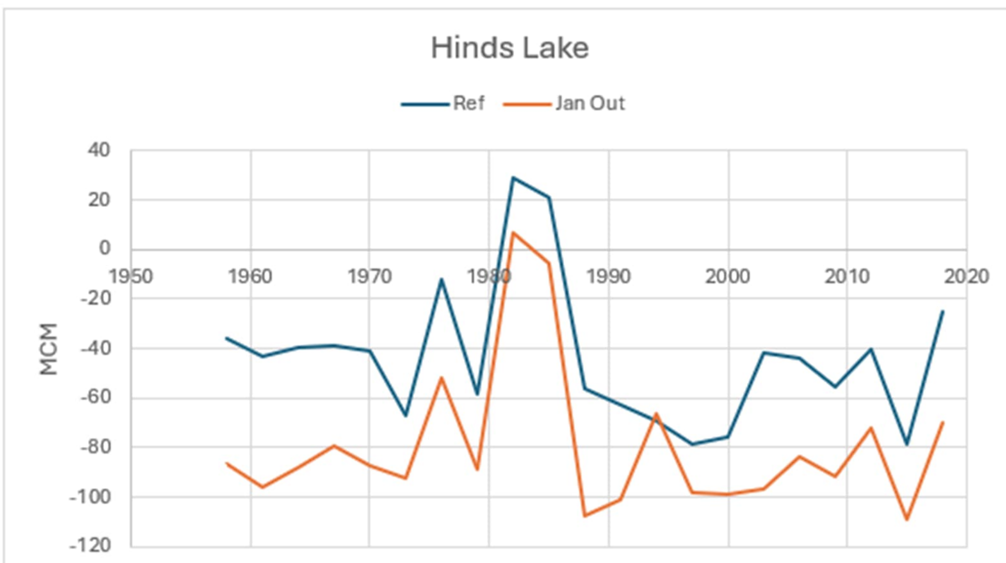


Figure 3-5: Cat Arm and Hinds Lake Storage Changes for January Outage Period

Average storage change trajectories for key reservoirs are illustrated in Figure 3-6 to Figure 3-8. As expected, a January outage draws storages down below the reference case and with inflow being low in winter Cat Arm and Hinds Lake take some time to recover.

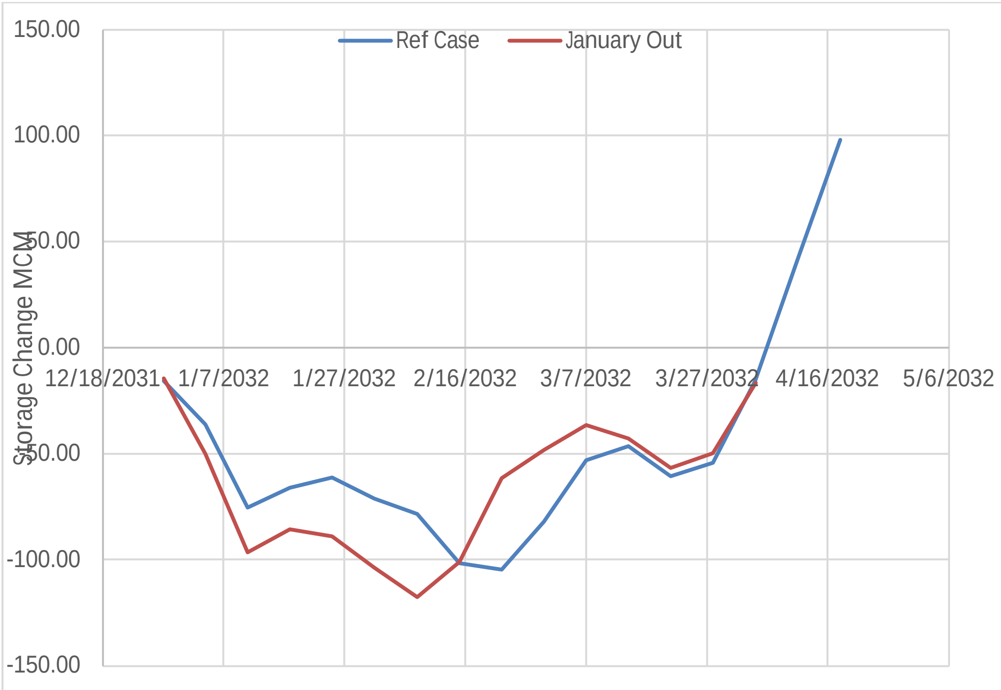


Figure 3-6: Bay d'Espoir Storage Change Comparison – January Outage Period

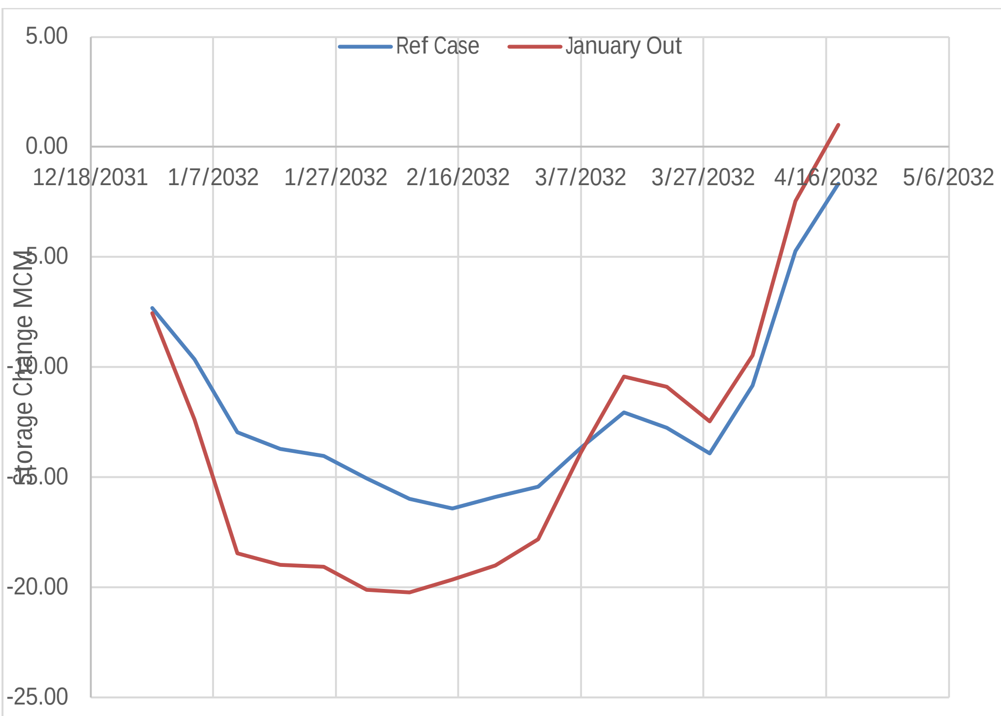


Figure 3-7: Hinds Lake Storage Change Comparison – January Outage

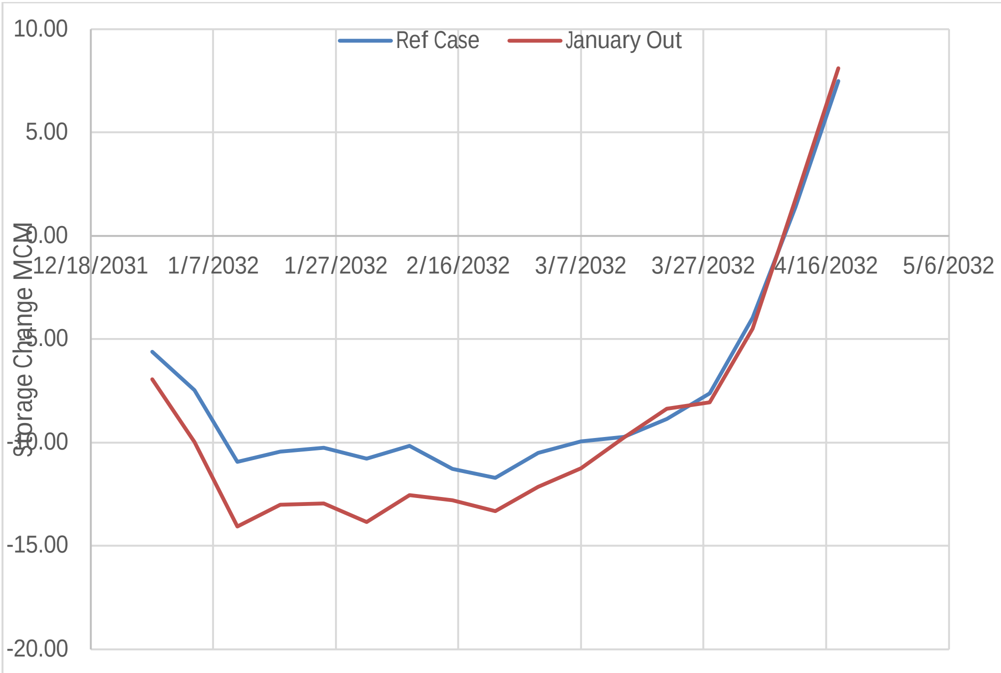


Figure 3-8: Cat Arm Storage Change Comparison – January Outage

3.2 March Outage

The simulations included a forced 6-wk outage starting in the first week of March 2032. The island imports through the LIL with and without the outage are illustrated in Figure 3-9.

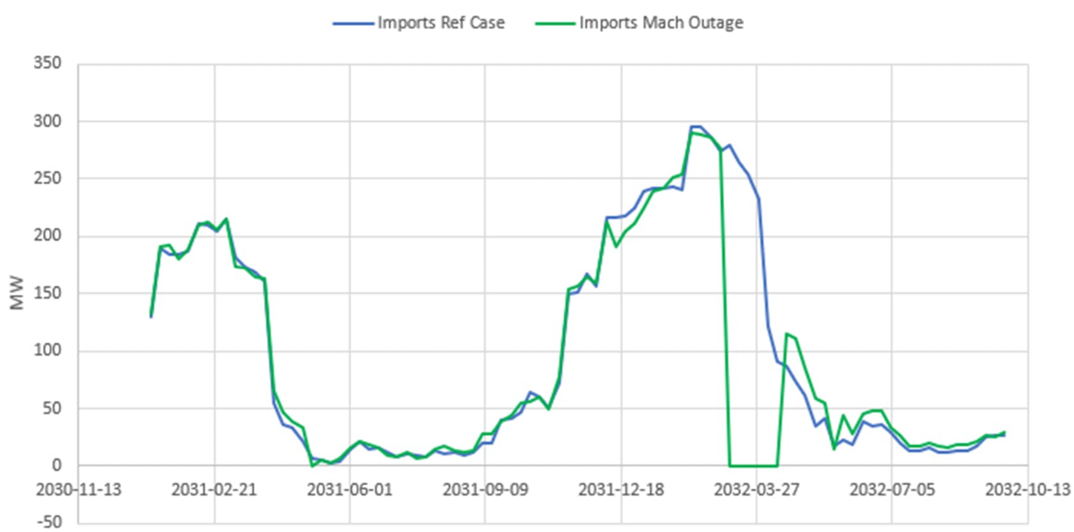


Figure 3-9: Island Imports March 2032

Island imports range from 290 MW at the beginning of March and drop to under 100 MW in April.

3.2.1 Generation Impact

The island hydro generation for the reference and March outage simulations are illustrated in Figure 3-10.

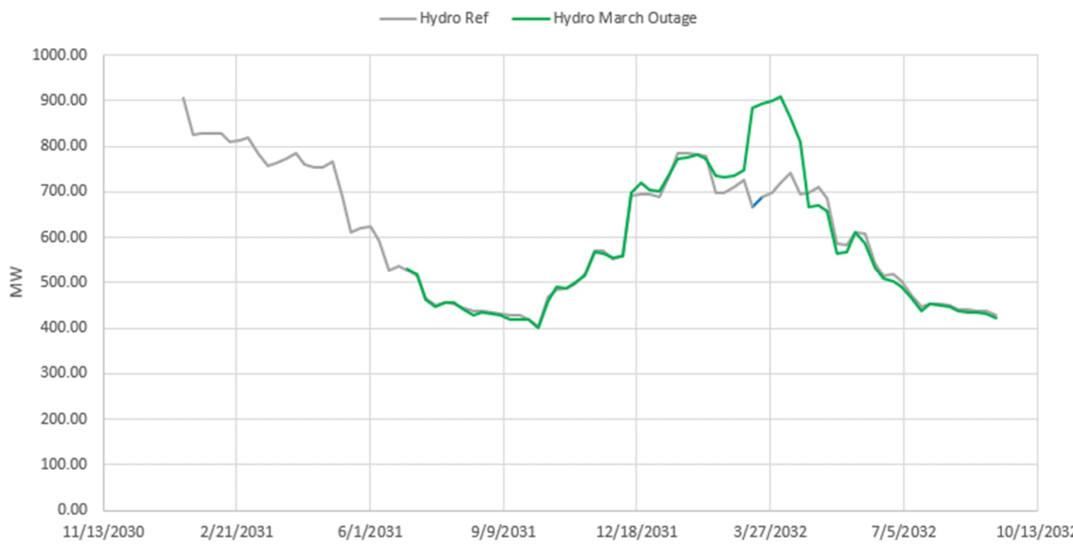


Figure 3-10: Hydro Generation for Reference and March 2032

There was no thermal generation in March for the reference simulation, but with the LIL outage around 100 MW of thermal was needed, as illustrated in Figure 3-11.

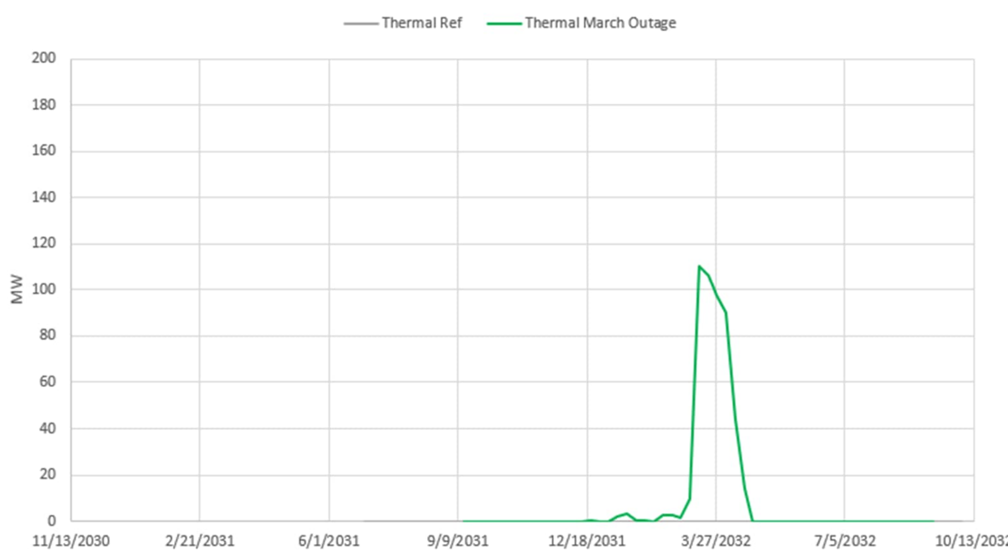


Figure 3-11: Thermal Generation for Reference and March Outage

3.2.2 Reservoir Impact

The additional draw on storage for major reservoirs, that is, over and above the drawdown experienced in the Reference case, is summarized in Table 3-2.

Table 3-2: Additional Storage Change March 2032 Outage

Reservoir	Additional Storage Change (MCM)
Victoria	-57
Meelpeg	-24
Long Pond	-240
Cat Arm	-35
Hinds Lake	-33

Annual storage change for each year of historic inflows (1958 to 2023) are shown for the March outage period for both reference and outage simulations are shown in Figure 3-12 and Figure 3-13 to demonstrate the variability from year to year.

Figure 3-12: Bay d'Espoir Storage Changes for March 2032 Outage Period

Figure 3-13: Cat Arm and Hinds Lake Storage Changes for March Outage Period

The average storage change trajectory for main hydro systems are shown in Figure 3-14 to Figure 3-16. Reservoir levels in the outage simulation were not forced to be the same as in the reference case at the start of the outage, but total hydro generation was. Therefore, minor differences in the start of outage level can occur.

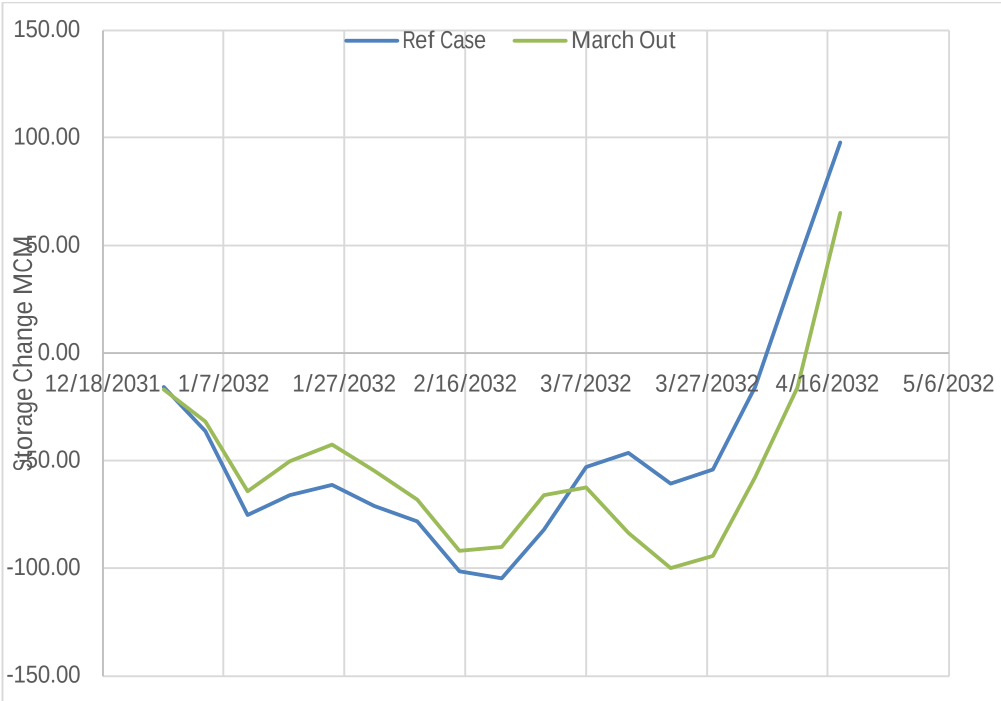


Figure 3-14: Bay d'Espoir Storage Change – March Outage

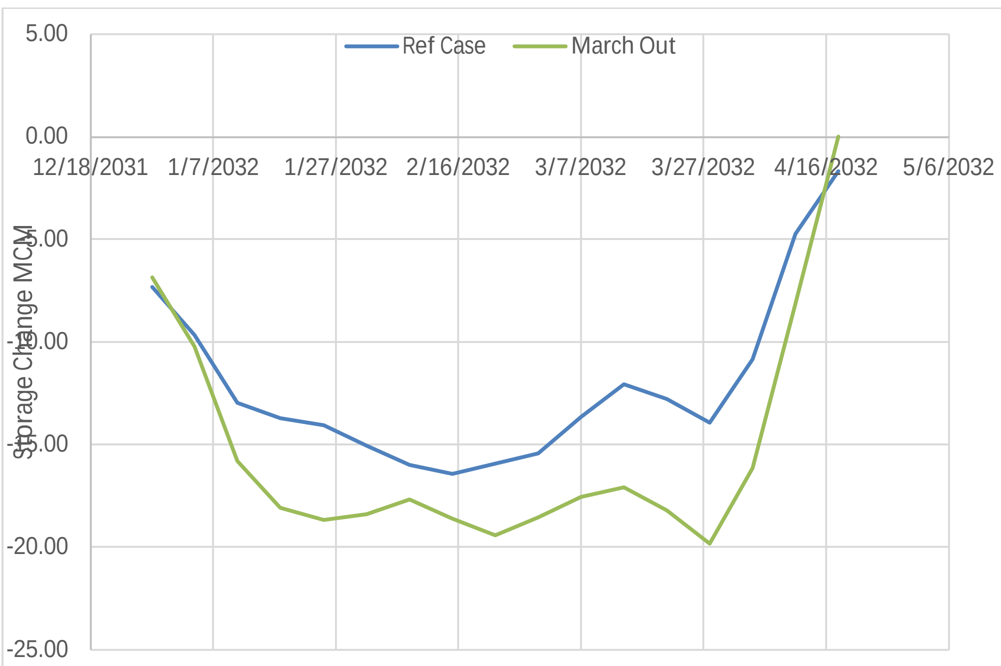


Figure 3-15: Cat Arm Storage Changes – March Outage

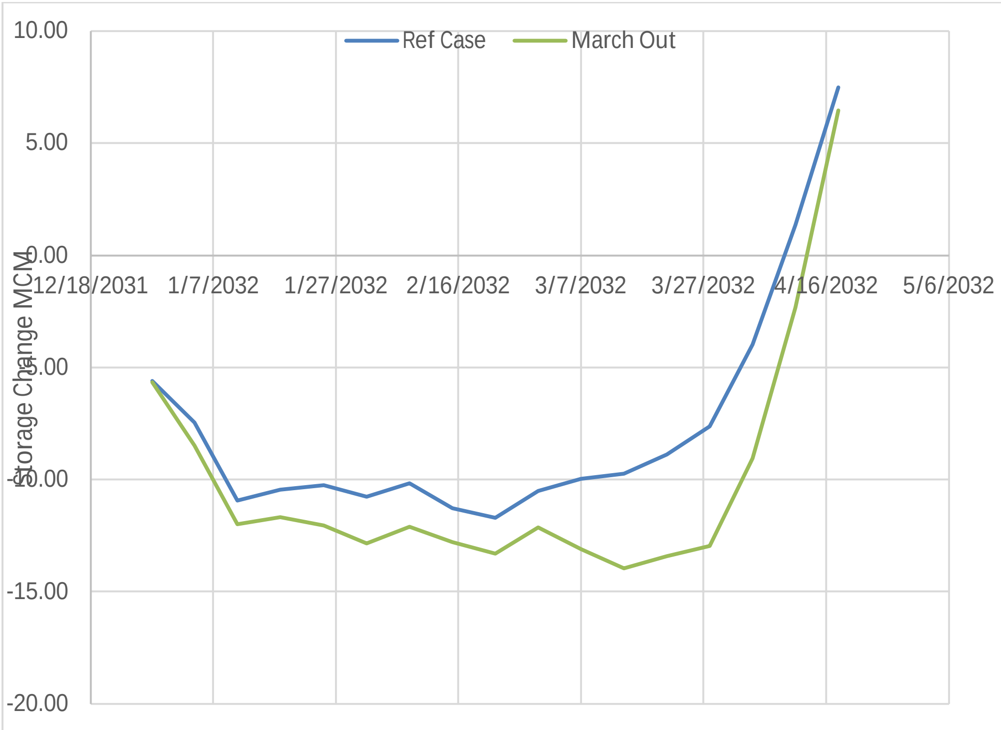


Figure 3-16: Hinds Lake Storage Change – March Outage

4. Conclusions and Recommendations

Simulations performed using historic inflows from 1958 to 2023 indicate that the island system has sufficient reservoir storage to handle 6-week January and March outages of the LIL. Both for the current system and the assumed 2032 composition.

The greatest impact of LIL outages on reservoir levels is for Long Pond, Cat Arm and Hinds Lake reservoirs, as expected. The Long Pond Reservoir is of particular importance, because the Bay ‘dEspir plant is the largest plant in the system. Also moving water from Meelpeg is subject to about 48-hour routing delay through Great Burnt Lake and Cold Springs Pond. In addition, the capacity at rated head, of the Upper Salmon plant is 200 m3/s, and the Bay d’Espoir plant has 440 m3/s capacity and with the addition of unit 8, it goes up to 550 m3/s. If more then 200 m3/s needs to move to Long Pond, flow must be spilled past the Upper Salmon plant.

Long Pond has upper and lower rule curves and for January 1st the range is 181.94 m to 180.34 m, respectively. In all the simulation Long Pond is at or close to the upper rule curve, to keep the head high on the plant, and to have enough water for the winter drawdown.

At the end of the March outage, Long Pond was drawn down to minimum rule curve levels of 178.978 metres for many of the inflow sequences, or about 40 cm lower than in the reference case. This shows that Long Pond levels are a concern during the prolonged outages, but in an emergency, it could be drawn lower.

For the 2032 simulations, unit 8 at Bay d'Espoir is added. It improves the overall efficiency of the plant and provides additional capacity, but operations of the plant are subject to the same storage and flow routing limitations, discussed above. All the simulations for the 2032 show that Long Pond follows the lower rule curve for most inflow sequences. The additional unit has an impact on Long Pond storage.

No spilling past the Upper Salmon plant was needed during these outages in 2024 or 2032.

The system composition changes considerably between 2024 and 2032. Hydro capacity increases with unit 8 at Bay d'Espoir, but thermal capacity goes from 713 MW down to 273 MW. Non-dispatchable wind generation goes from 54 MW to 354 MW in 2023. While the 300 MW of additional installed wind capacity. Wind generation is highly variable and with less dispatchable generation resources, the ability of the system to respond to outages and/or variability in wind generation is reduced in 2032.

Appendix D

Appendix D

What Was Said Report: 2024 Public Engagement

Reliability and Resource Adequacy Study Review

What Was Said Report

2024 Public Engagement
Reliability and Resource Adequacy Study Review

Foreword

It's a time of transition for our electricity system. We're planning for the future and working hard to ensure safe, reliable electricity—it's something we all need—and we need more. It's Hydro's responsibility to guide our province forward. We have decisions to make and we need to make them at the right time. We need your views as we make those decisions.

I want to personally thank everyone who has engaged with us over the past year, whether around meeting tables throughout the province or through our online surveys.

We asked some tough questions, and we appreciate that many of you took the time to share your thoughts. Knowing what is most important to you will help us make the best decisions. We will need to ensure our decisions meet the regulations that apply to our industry and follow the regulatory processes that provide oversight of our work.

A lot has been said, and we've been listening.

Not everyone agrees on everything. And that's ok. We will consider all perspectives, technologies, and research to strike the right balance. But as you will see from the report, it will be a challenge to meet everyone's expectations. What I can promise, is that we will do our absolute best to make the decisions that ensure a reliable, cost-conscious, and clean energy future for this province with your views in mind at all times.

Please be safe in all you do,

Jennifer Williams

President and CEO, Newfoundland and Labrador Hydro

Contents

Engagement with Hydro 4
Engage Who We Serve 5
Targeted Engagement 6
With Government 6
With Our Intervenors 6
With Indigenous Leadership 6
With Communities 7
With Industrial Customers 7
With Industry Influencers 7
Commercial Customers 8
Methodology 8
Results 8
Public Engagement 10
Methodology 10
Launch Communications 11
Feedback Panel Survey Methodology 12
What Was Said... 13
Reliability Today 13
The Right Balance 17
Cost 21
Clean Energy 22
Electrification 24
Growth 26
Options 27
Combustion Turbine 29
Open-Ended Comments (Open Survey) 32

Open-Ended Comments (Panel Follow Up) 33
Your Comments 34
Cost 35
Cost of Living 35
Least Impact on Rates 35
Vulnerable Communities 36
Fairness 36
Reliability 37
Clean Energy 38
Electrification 39
Options/Growth 40
Hydroelectric 40
Wind/Hydrogen 41
Combustion Turbine 42
Other Renewables 44
Non-Renewables 44
Transmission 45
Customer Options 46
Demand Management 46
Net Metering 46
Labrador 47
Outages 47
Diesel Reduction 47
Upper Churchill 48
Muskrat Falls 48
Corporate Policies 50
Energy Marketing 52
Communications 52

Engagement with Hydro

Every year, we plan for multiple engagement touchpoints to ensure we hear as many perspectives as possible from those we serve, directly or indirectly. We know our investments and operations today and in the future touch every person who uses electricity in the province. While many interested parties are engaged and represented through the regulatory process, we wanted to ensure everyone had an opportunity to share their thoughts with us.

This report provides an overview of our targeted engagement activities as well as our broader public engagements.

Targeted Engagement:

1. Intervenors (parties that participate in the regulatory process);
2. Interested parties outside the regulatory process; and
3. Commercial Customer Satisfaction survey.

Public Engagement:

1. Digital survey with residential, commercial, and industrial customers; and
2. Follow-up online engagement with Hydro's Feedback Panel—a public voluntary panel that anyone can join.

GOAL:

To continue the dialogue with our customers and interested parties regarding the future of electricity in our province and to inform Hydro's 2024 Resource Adequacy Plan.

Engage Who We Serve

Hydro values the perspectives of everyone who has an interest in or is affected by decisions impacting the delivery of safe, reliable electricity. It's embedded in our values and is 1 of 11 Goals in our Strategic Plan—**ENGAGE WHO WE SERVE**.

> *"We will proactively engage and listen to our community to better understand their expectations and demonstrate our delivery on those expectations. We believe in listening to those we serve, being open and transparent about our operations, and ensuring everyone can better understand our work and our commitment to them.*
>
> *By proactively engaging with interested parties, we can seek to understand their needs and operate with their unique positions and interests in mind. We will do this by sharing relevant information, seeking input to expand our knowledge, and collaborating with industry peers and partners to benefit the people of the province."*
>
> *-Hydro's Strategic Plan*

Targeted Engagement

With Government

Hydro and the Government of Newfoundland and Labrador are partners in delivering a clean energy future for the province. We maintain open dialogue, particularly with the Department of Industry, Energy, and Technology and the Department of Environment and Climate Change, which are mandated to advance efforts to achieve net-zero by 2050.

<u>What is being said:</u> We want to see continued progress toward our Province's climate goals, including decarbonization of the electricity grid and support for industrial and residential electrification efforts. As Hydro works to maintain system reliability and expand the grid to serve growing demand, we want to see evidenced decision-making that honours lessons from past projects.

With Our Intervenors

Through the regulatory process, we keep an open dialogue with the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB) and registered Intervenors. The Intervenors in the *Reliability and Resource Adequacy Study Review* proceeding include the Consumer Advocate, Newfoundland Power (NF Power), Island Industrial Customer Group, and the Labrador Interconnected Group. As Intervenors, these groups have the opportunity, and duty, to review and scrutinize our work, our evidence, and our decisions—and ask questions. Through this process, we have responded to an extensive number of questions from these parties.

<u>What is being said:</u> We want a transparent, rigorous decision-making process. We want to ensure that decisions are being made with customer impacts top of mind and aligned with the delivery of least-cost reliable service in an environmentally responsible manner.

With Indigenous Leadership

Hydro acknowledges that we operate on the traditional lands of Indigenous peoples in Newfoundland and Labrador. This is why we work to keep open communications and engage with Indigenous communities in the province. We have met with and will continue to meet with these groups to discuss reliable energy.

<u>What is being said:</u> We want to be engaged earlier in the process. We want to ensure there are economic opportunities for indigenous communities and people.

With Communities

Our teams also work and live in communities across the province. We understand that our decisions affect communities and the people who live in them. We have met with and will continue to meet with municipalities and leaders to discuss potential projects and development opportunities.

What is being said**:** We want economic development and community impacts to be considered in future decisions. We want Hydro to ensure our communities have access to safe and reliable electricity and enable economic development via the ability to supply new customers in and around communities. We prefer investment in renewable energy, but are concerned about the cost of living for our residents and so, cost must be considered. We want proactive communications about decisions that affect our communities.

With Industrial Customers

Hydro considers the needs of our industrial customers on an individual basis. Our teams maintain open lines of communication to address concerns, talk about future needs, and ensure this unique perspective is heard and understood. Discussions with wind and hydrogen proponents is ongoing to help them achieve their development goals, and in support of the province's policy objectives and within our own mandate to ensure safe and reliable service for our customers.

What is being said**:** We are concerned about the reliability and availability of firm energy to meet our needs. We are interested in interconnection to the grid and need to understand the process and impacts. We are actively managing the costs of electricity in our business and are concerned about potential rate increases.

With Industry Influencers

Hydro's engagement extends into the community of industry partners and leaders in green business. Led by Jennifer Williams, President and CEO of Hydro, we engaged this group of influencers through panel discussions, presentations, and meetings with Energy NL, econext, Labrador Chamber of Commerce, Net-Zero Advisory Council, and MUN Engineering, as well as media engagements and participation in national and international industry association and speaking opportunities.

What is being said: We are concerned about the timely transition to green energy and the urgent actions required to meet expected growth. We want economic development opportunities considered in decisions for new projects. We want to ensure we are supporting regional, national and international economic and environmental goals.

Commercial Customers

Methodology

We launched our annual Commercial Customer Satisfaction telephone survey on November 20, 2023, which remained in market until December 20, 2023. We sampled our database of commercial customers (n=1,875). A total of 284 commercial customers completed the survey, which provided a margin of error of ±5.4%.

To allow for analysis by region, disproportionate stratified sampling was used to draw a random sample from Central (n=96), Northern (n=111), and Labrador (n=77). Responses were weighted to ensure proportionate representation of the commercial customer population at the overall level.

Results

Commercial customers continue to be satisfied with Hydro's service reliability.

93% provided a rating of 7 or higher when asked to rate their satisfaction with the supply of electricity they receive from Hydro using a scale of 1 to 10, with 1 being *'not at all satisfied'* and 10 being *'very satisfied.'* Satisfaction with reliability was highest in the central region.

We asked customers to rate the importance of a number of attributes relating to customer service, rates, and reliability. We then asked them to rate their satisfaction for each attribute. We then looked for gaps to identify areas where we can improve. The areas with the largest gaps included the price for electricity and the number of power outages.

In 2023, satisfaction ratings were highest for '*friendly and courteous employees'* and *'Concern for public safety'* and lowest for '*price you pay for electricity.'* This is consistent with satisfaction levels from 2021.

The analysis also identified the factors that had the most influence on perceptions of overall satisfaction with Hydro. Since 2021, there has been a shift in those drivers with *Supply of Electricity* moving into the top spot, followed by *Customer Service, Communication,* and *Community Investment.*

Top Drivers 2021	Top Drivers 2023
Customer Concern	Supply of Electricity
Billing	Customer Service
Supply of Electricity	Communication
Customer Service/Price	Community Investment

Public Engagement

Methodology

The 2024 digital engagement was an opportunity for all provincial residential and business customers to share their thoughts on our energy future. The online survey, similar in methodology to the 2018 engagement, was administered by a third-party research partner and sets the stage for future touchpoints by determining areas of focus and how the public would like to engage further with us.

Digital Survey → Identify Gaps → Re-Engage → What Was Said

Our methodology is consistent with engagement activities used by other utilities across Canada and our approach follows IAP2 (International Association for Public Participation) principles.

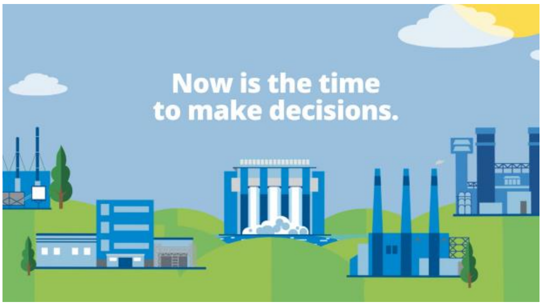
The public could participate in one of two ways—a link available via an online survey or through Hydro's electricity feedback panel, created in 2018. The breakdown of respondents was similar to the general population and weighting was applied by age, region, and gender to ensure results were representative.

Survey Questions

Questions focused on reliability, cost, investment, growth, clean energy, and options for new sources of electricity. The questions were divided among three sections. Residents were prompted to watch a video that provided context for the questions in each section.

Survey Response

The survey was open to residents of Newfoundland and Labrador between January 23 and February 13, 2024. Overall, 1,763 residents started the survey, with 1,667 completed responses collected. On average, the survey took approximately 14 minutes to complete. Hydro recognizes gender diversity. There were cases where differences among those identifying as male or female were noted—we have included those in the report.



Launch Communications

Website Content

A notice was posted to nlhydro.com and appeared under public notices and news releases (https://nlhydro.com/share-your-thoughts-on-reliability-rates-and-growth-of-the-electricity-system/). A banner takeover on the nlhydro.com homepage also directed web users to the online survey platform.

Email Engagement

An email was sent to 983 members of our Feedback Panel who had consented to receive future research invitations. These customers were invited to participate in the survey and lend their voice to the process.

Other parties notified by email included the Government of Newfoundland and Labrador, PUB, Intervenors (NF Power, Consumer Advocate, Island Industrial Customer Group, and Labrador Interconnected Group), and all industrial customers.

Internally, we also communicated the survey to our employees and Board of Directors by email. The results of the internal participants were collected but excluded from the data analysis.

Media Pitching

We pitched both NTV and VOCM to amplify provincial reach. NTV ran a story across morning, evening, and late news broadcasts and VOCM reported multiple times across 590 (Eastern) 650 (Central) and 570 (Western). VOCM also posted content online.

NTV BROADCAST	VOCM RADIO (590, 650, 570)	VOCM ONLINE
Reach: ~46,000	Reach: ~64,000	Reach: ~692,000 Views: 13,500

Social Media Content

Leveraging Hydro's social media channels to inform and engage customers, Facebook posts were also promoted.

Facebook	Twitter	LinkedIn
Reach: 9,294	Reach: 6,065	Reach: 3,218

(Source: Meltwater, 2024)

We asked residents if there were other ways they wanted us to engage with them—87% said no. (n=1,667)

Feedback Panel Survey Methodology

Following the initial survey, several areas were identified that required more information. Our research partner sent a secondary set of questions back out to our panel and any respondents from the first round that consented to joining the feedback panel.

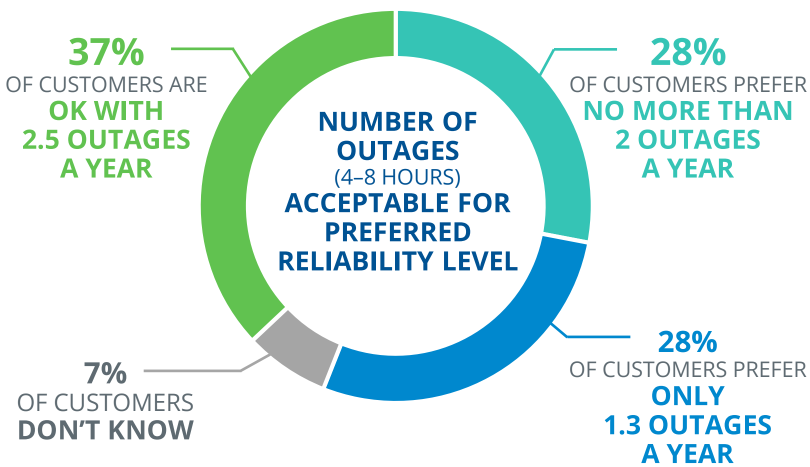
The second survey was open to 1,046 panel members (including those opting into the panel from the open survey), with 451 members (43%) completing the survey between February 23 and 28, 2024. On average, the survey took approximately 8 minutes to compete.

Results were weighted by customer type (Hydro or NF Power) to be reflective of customer distribution. Given the online methodology and use of a non-probability sample, a margin of error is not applied to the results.

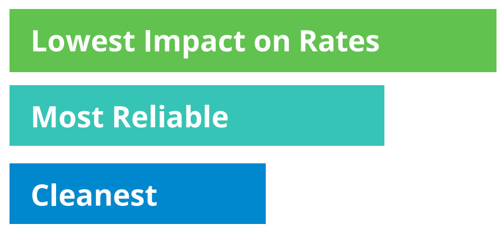
What Was Said...

More than 2,000 responses

More than 1,000 comments



RESIDENTS PRORITIZE LOWEST RATE



Themes:

- Customers recognize we have a reliable system that is largely from renewable sources.
- Reliability is non-negotiable, but customers do not want to pay more for fewer or shorter outages.
- Customers are concerned about the cost of living, particularly for seniors, and this includes electricity rates.
- Many feel they do not have enough information to inform an opinion on some topics.
- There is little consensus on options for new sources of electricity, although many agree we need to prepare for growing electricity needs.
- Customers prioritize lowest impact on electricity rates over having the most reliable or cleanest energy.
- There is a lack of trust in utilities and misinformation about corporate policies
- Muskrat Falls has not been forgotten.

Reliability Today

We asked residents how they feel about the current reliability of their power supply, as analysis is happening now to determine the amount and type of investments we make for the future of energy supply in our province.

While the engagement results showed slight differences among regions and age groups, overall residents indicated they believe NL's power system to be reliable, on par with 2018. Labradorians rated reliability 11% lower than Islanders.

MOST RATE THEIR ELECTRICITY SERVICE AS RELIABLE.

Q. How would you rate the reliability of the electricity you receive? (n=1,677; score 7–10; 10-point scale)

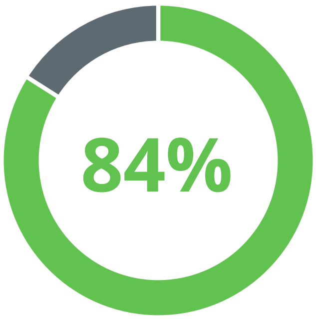
Part of ensuring reliable service is maintaining backup generation that can be brought online in the event we need more electricity to supply customers during planned or unplanned maintenance activities or during a system event, such as an outage.

79% were aware we have backup generation options (90% in Labrador)

We asked residents to reflect on service interruptions over the past year, and recall if they had experienced fewer, more or about the same number of outages as the previous year. The majority said about the same or fewer. There was little difference between the Island and Labrador.

MOST RECALL EXPERIENCING THE SAME OR FEWER OUTAGES.

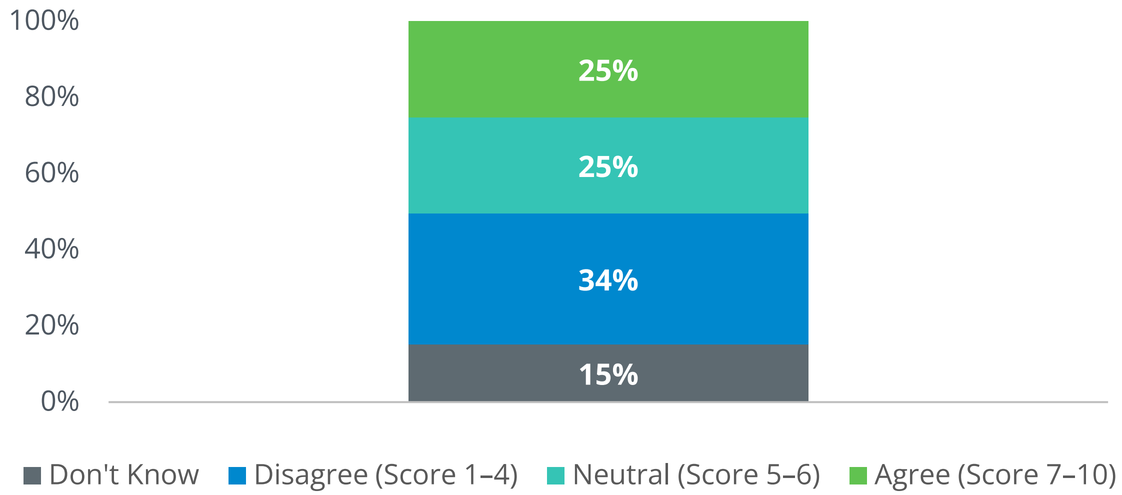
2024



Q. Over the past year, have you experienced fewer, about the same, or more outages than you experienced in previous years? (n=1,667 selected '*about the same*' or '*fewer*' outages)

We asked residents about their comfort level with our newest, and longest, transmission line that brings electricity to the Island from the Muskrat Falls plant—the Labrador Island Link. Despite its strong performance through 2023 and this current winter season, residents were mixed in terms of their *perceived* reliability of the Labrador Island Link. Males were more likely to disagree that they were comfortable with the link's reliability than females.

MIXED LEVEL OF COMFORT WITH THE LABRADOR ISLAND LINK'S RELIABILITY.



Q. Please indicate the extent to which you agree or disagree with the following statement: I am comfortable with the reliability of the Labrador Island Link (n=1,667; 10-point scale).

So, how is Muskrat Falls Generating Facility and the Labrador Island Link performing?

The Labrador Island Link performed well in 2023 and helped us generate 92% of our electricity from renewable sources. From October to December, more than 850 GWh was delivered over the line, triple the deliveries for the same period in 2022.

The Labrador Island Link had an equivalent Forced Outage Rate of 4%, essentially available 96% of the time (not accounting for planned maintenance outages). The Muskrat Falls Plant also performed better than the Canadian average for reliability.

“Forced Outage Rate” is the industry’s standard metric to qualify an assets reliability—how often an asset was unexpectedly offline.

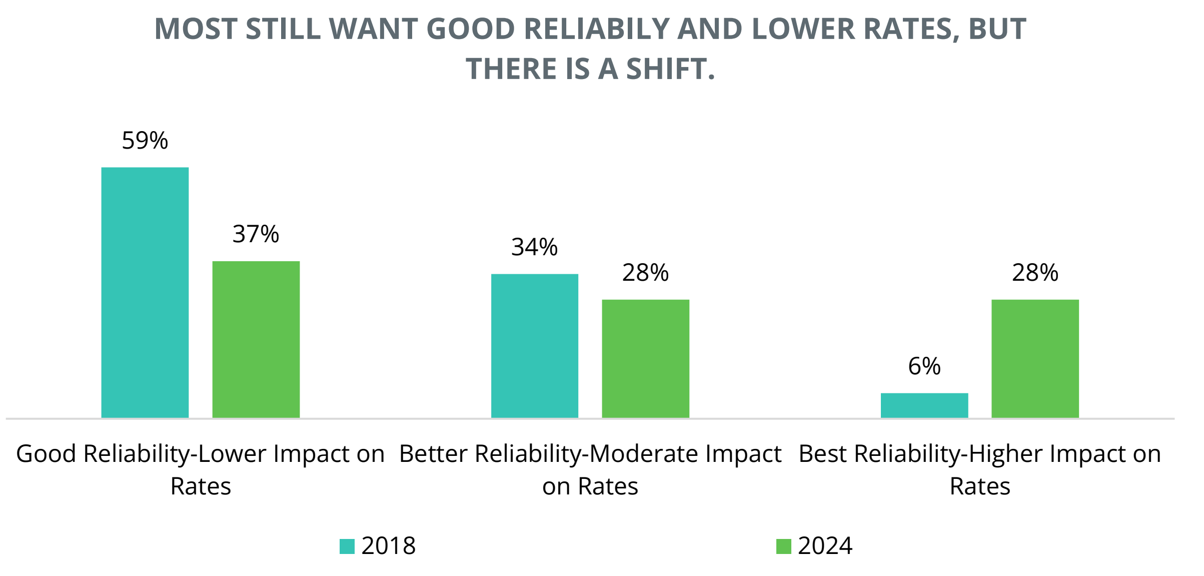
The Right Balance

There is a cost to maintain all assets so they are ready for service. Improving reliability also requires additional investment. A decision to upgrade or add to our supply of power has a cost, which can impact customer rates. More investment can help ensure fewer or shorter outages and has a greater impact on how much customers pay for electricity.

We asked residents for their thoughts on the right balance between reliability and the cost of those investments for customers.

Residents demonstrated they are cost-sensitive and would prefer additional investments in the system be made cautiously.

Consistent with 2018, residents favoured an approach that involves good reliability with a lower impact on cost. But there has been a shift towards a desire for increased reliability, despite a higher impact on electricity costs. This shift doesn't match the response to questions about willingness to pay more for reliability. There was a positive correlation between age group and level of reliability. The majority (52%) of younger adults (18–34) choose "*Good*" compared to only 26% of older adults (55+). Older adults leaned towards the "*Best*" level (37%) compared to only 13% of younger adults.



Q. Please select the alternative that best describes your preference (n=1,667).

The majority of residents noted a preference for cautious investment. It's our responsibility to ensure that any recommended resource plan ultimately balances cost with reliability.

We then asked residents to tell us how many outages would be acceptable given their preferred level of reliability. Across all levels, the mean response was 2 outages for Island residents and 1.6 for Labradorians.

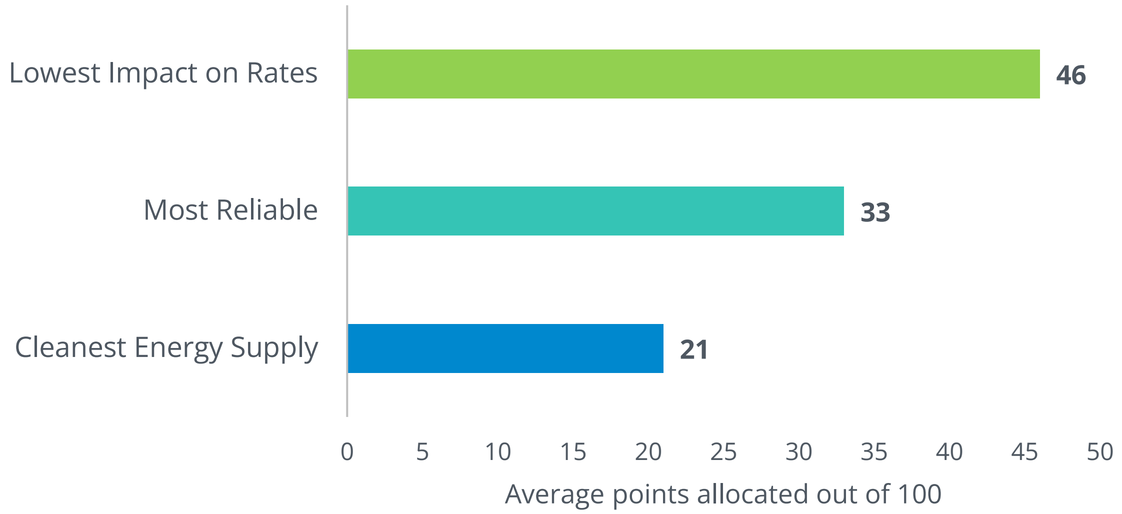
NUMBER OF OUTAGES (4–8 HOURS) ACCEPTABLE FOR PREFERRED RELIABILITY LEVEL

GOOD	BETTER	BEST
37% OF CUSTOMERS ARE OK WITH **2.5 OUTAGES A YEAR**	28% OF CUSTOMERS PREFER NO MORE THAN **2.0 OUTAGES A YEAR**	28% OF CUSTOMERS PREFER ONLY **1.3 OUTAGES A YEAR**

Hydro's Island customers experienced the best system reliability in over a decade with the lowest service interruptions since 2012.

To help provide clarity as we strive for balance between increased investment and improving reliability while we consider the environment, we asked our Feedback Panellists to assign 100 points among three factors. Such factors must be considered by Hydro as we select viable solutions and evaluate new technologies. On average, Panellists assigned the most points to the lowest impact on electricity rates. Most reliable ranked second and cleanest energy solution ranked last. Average point allocations are fairly similar across demographic segments.

LOWEST IMPACT ON RATES IS A PRIORITY FOR RESIDENTS.



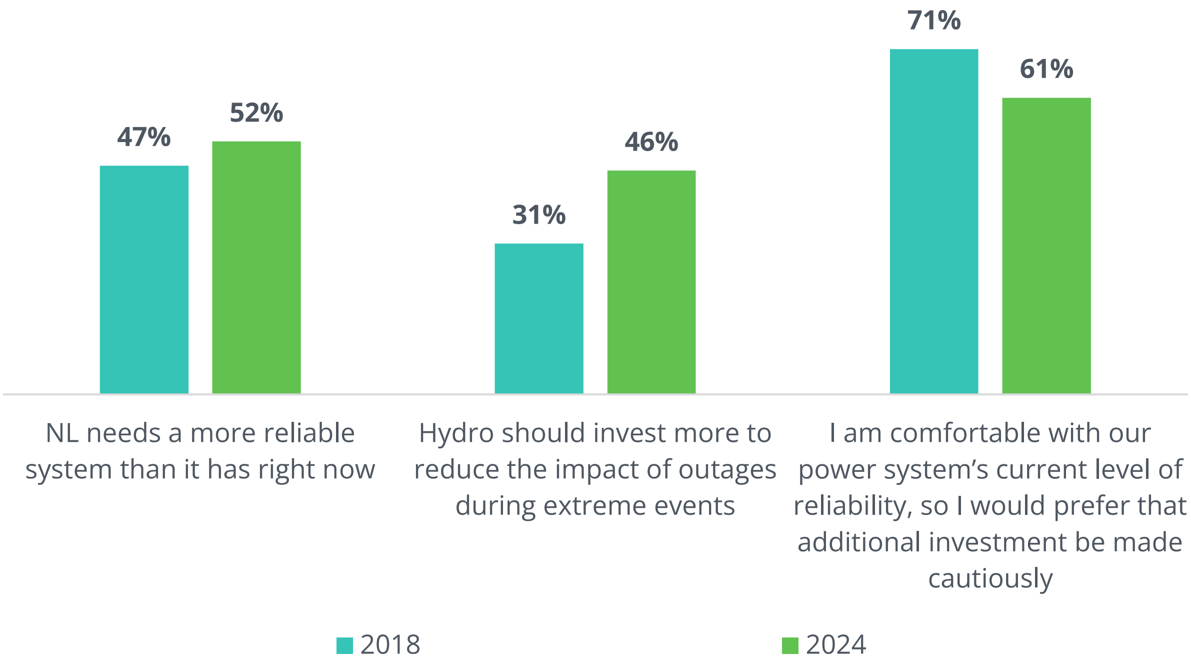
Q. Please tell us what's most important to you by assigning a value to each factor. You have 100 points to share between all three factors. The more points you give to a factor, the higher the importance you give to it (n=451).

Hydro must balance these three key factors as we consider the technologies and projects that are will best meet our customers' growing electricity needs.

We have been seeing more frequent and severe weather events, which will likely increase due to the impacts of climate change. Some utilities choose to make significant investments to help protect the system from these extreme risks and some have yet to invest materially in this system hardening.

Residents remained divided on the topic of reliability and investment. Generally, most were still comfortable with current reliability and prefer cautious investment. There were some slight differences between demographics, for example, young adults (18–34) and Labradorians perceived a need for a more reliable system and older adults (55+) were more likely to perceive they saw an improvement in reliability over the past few years. Although opinions remain divided, since 2018 there is a small upward shift in recognizing a need for investment in reliability.

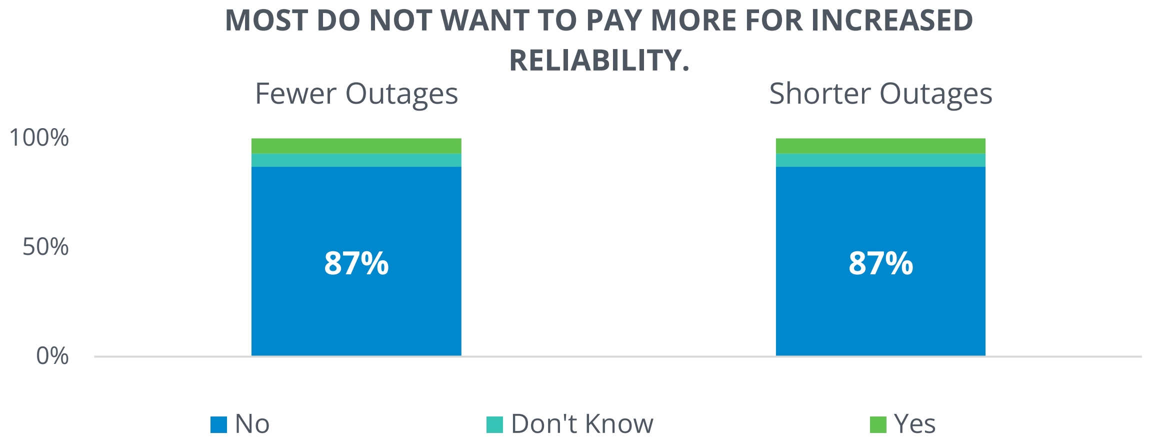
OPINIONS ON INVEST IN RELIABILITY REMAIN DIVIDED.



Q. To what extent do you agree or disagree with the following? (n=1,667, Score 7–10, 10-point scale).

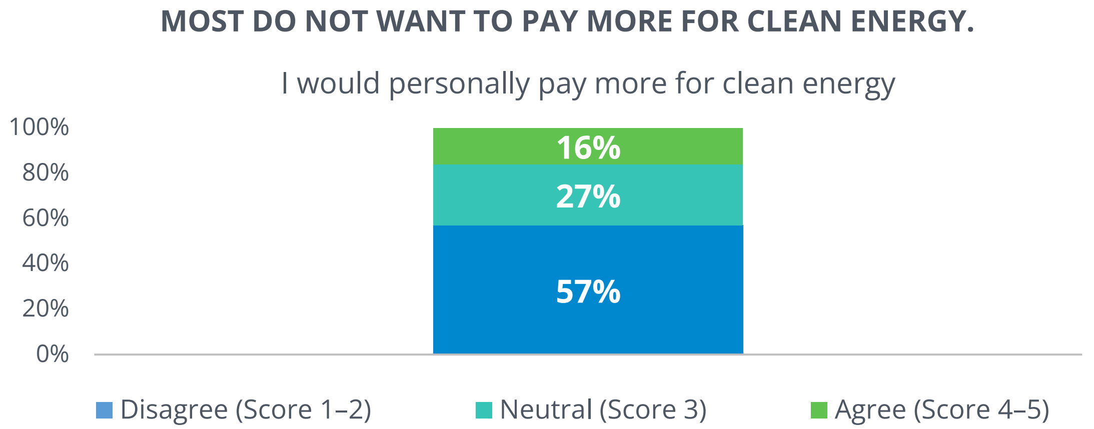
Cost

We know electricity rates are a concern for Newfoundlanders and Labradorians. Although we saw a shift towards a desire for increased reliability, which comes with a higher impact on rates, it didn't translate into a willingness to pay more for increased reliability.



Q. Would you be willing to pay a little more for electricity if it meant fewer outages/shorter outages? (n=1,667).

We also asked our Panellists if they would be willing to pay more for clean energy. Again, the majority did not want to pay more.



Q. To what extent do you agree or disagree with the following statement: I would personally pay more for clean energy? (n=451, 5-point scale).

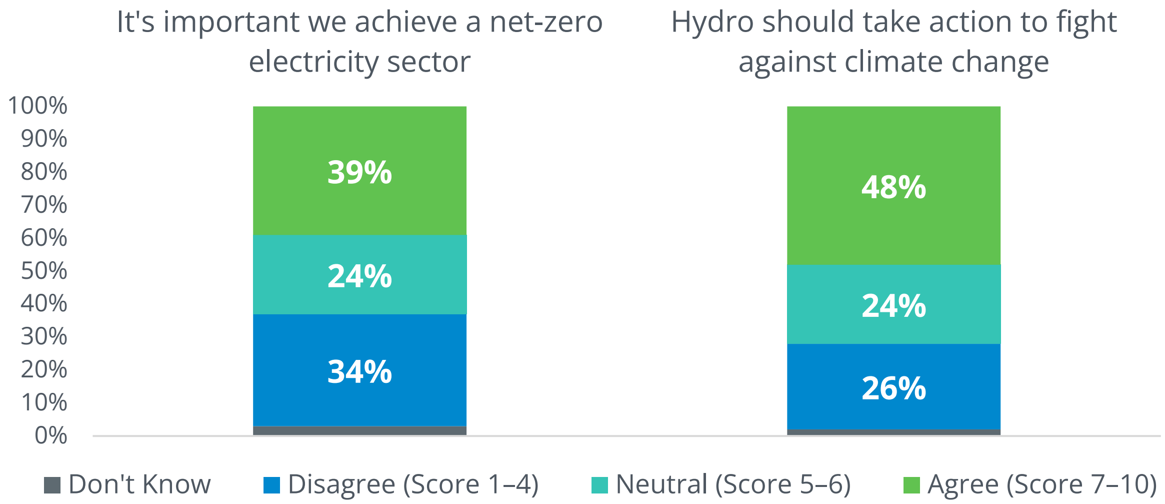
Clean Energy

There is lots of chatter these days about climate change, net-zero, clean energy, and renewable energy—it can be a lot to take in. While Hydro has made great progress, generating 92% of our electricity from renewable sources in 2023, we do have some fossil-fuelled assets, which includes the Holyrood Thermal Generating Station, generators in some isolated communities, and some backup generation. Reaching the Canadian net-zero emissions goal will require solutions, decisions, and investment in our jurisdiction.

82% of residents were aware that the Government of Canada has set a target for a net-zero emitting electricity industry by 2035.

We wanted to get a sense of what residents are thinking—is this important to people? Who is responsible? There were many differing opinions on the topic and very little consensus on most questions. There was slightly more agreement than disagreement on the importance of achieving net-zero and Hydro taking action against climate change. There was also more agreement on both items from females than males and from older adults than younger and middle-aged adults.

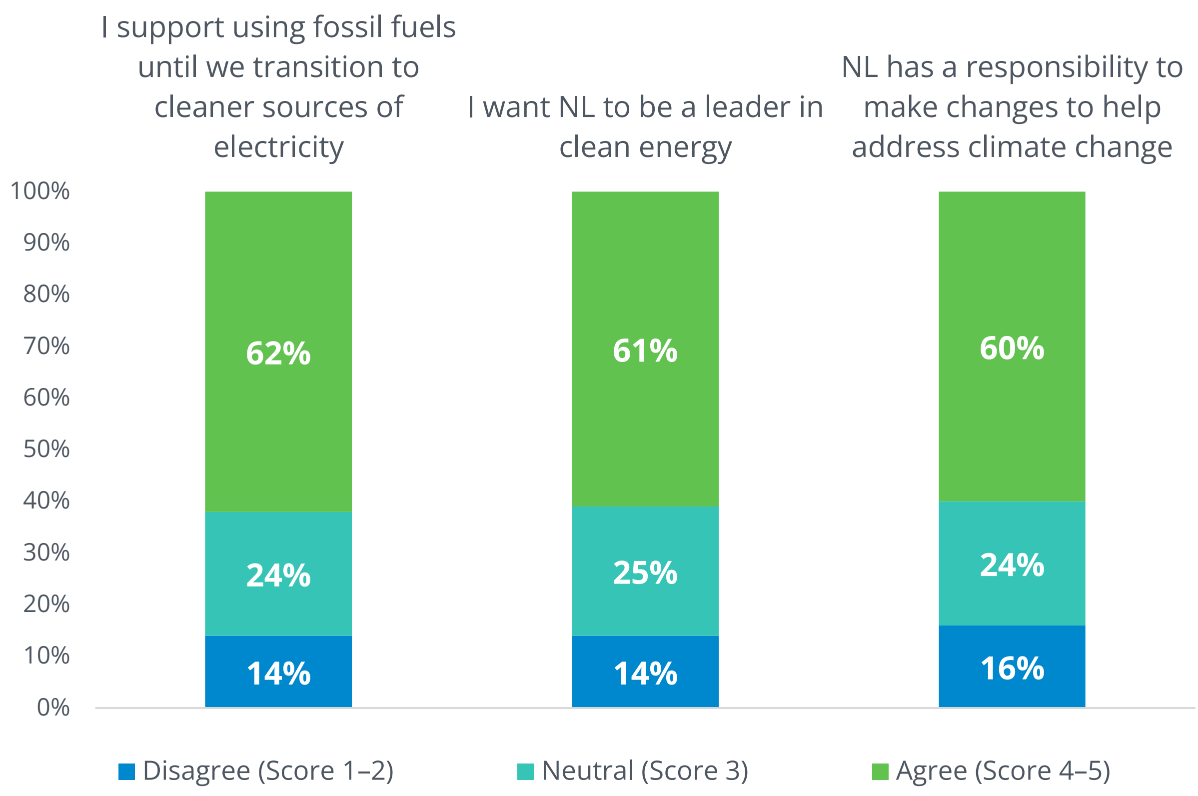
OPINIONS ON CLIMATE CHANGE ARE VARIED.



Q. To what extent do you agree or disagree with the following statement: I would personally pay more for clean energy? (n=1,667; 10-point scale).

We also asked our Panellists to indicate their level of agreement or disagreement with three statements. There was moderate agreement for 3 of the statements, with 6 in 10 agreeing they support using fossil fuels for electricity generation until we transition to cleaner sources of electricity; they want the province to be a leader in clean energy and Newfoundlanders and Labradorians have a responsibility to make changes to help address client change. Opinions are largely similar across demographic segments.

MAJORITY SUPPORT FOSSIL FUELS AS WE TRANSITION TO BECOMING A CLEAN ENERGY LEADER



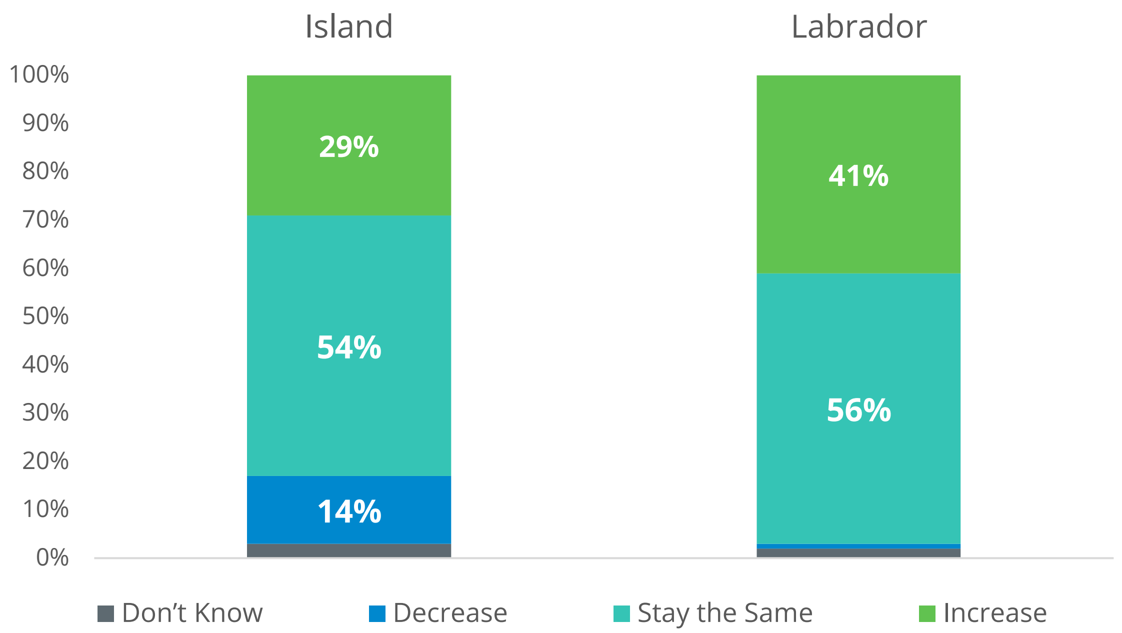
Q. To what extent do you agree or disagree with the following statements? (n=451; 5-point scale).

We're well on our way to a clean energy future. In 2023, 92% of electricity generated for homes and businesses across this province came from non-emitting sources.

Electrification

Electrification means that things that were once powered by fossil fuels (such as diesel, gasoline, or propane), are moving to be powered by non-emitting electricity. It is estimated that the province's current supply will need to double to meet this new demand. Many factors will influence how much electricity we use in our homes over the next 10 years. We asked residents if they expected their electricity use to change in the next 10 years. The majority (consistent across all demographic groups) said they expected electricity use to remain constant; however, those expecting an increase said electrification was one of the reasons. Residents predicting an increase in their electricity use is consistent with recent consumer trends in electric vehicle adoption. In 2023, 9.1% of vehicles registered in the province were electric or hybrid, up from less than 2% in 2020.

SOME PREDICT ELECTRICTY USE WILL INCREASE OVER THE NEXT 10 YEARS.



Q. Do you expect your electricity usage to increase, stay the same, or decrease over the next 10 years? (n=1,667).

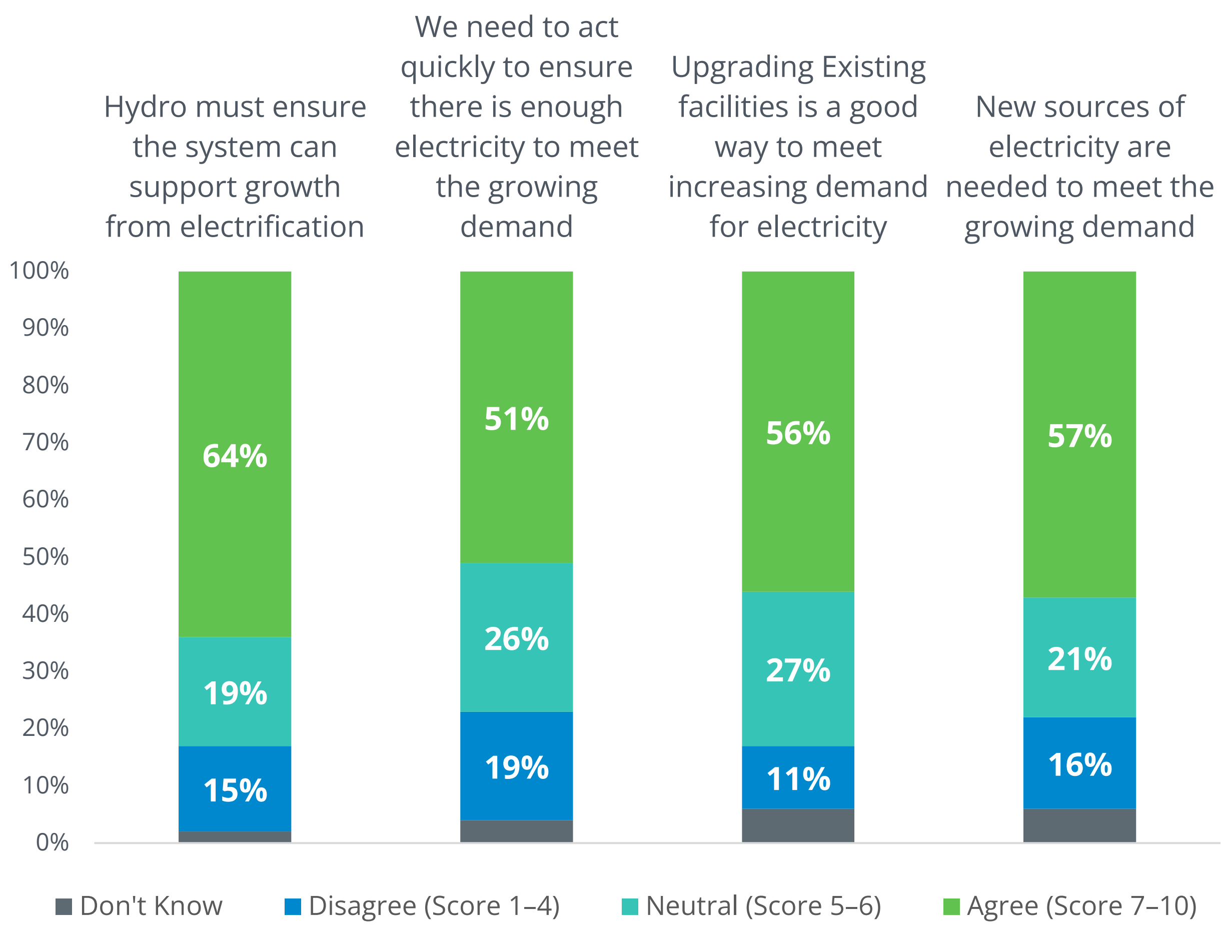
MANY ATTRIBUTED THE INCREASE TO ELECTRIFICATION.

Q. Is electrification one of the reasons for this increase? (n=493, Chose Yes)

Growth

To prepare for the additional demand expected in the next 10 years and beyond from our current and new customers, and in response to electrification, we will need to look at new supply solutions to accommodate this growth. We asked residents their level of agreement with several statements referencing Hydro's response to growing demand. The majority of residents agreed with all statements with the strongest agreement from older adults.

MAJORITY AGREE WITH TAKING ACTION TO SUPPORT GROWING DEMAND.



Q. To what extent do you agree or disagree with the following statements? (n=1,667, 10-point scale).

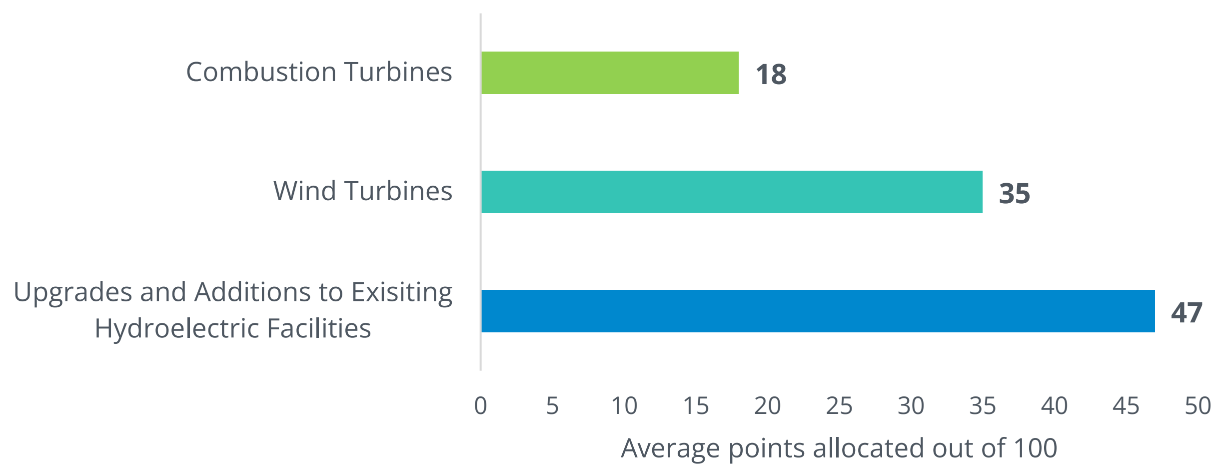
Options

As part of our ongoing planning, we are looking at many different technologies for generating electricity on the Island. We're considering factors such as cost, proven reliability for our jurisdiction, and environmental responsibility to make these decisions. There are a few frontrunners, but we'll keep looking at other ideas in the future, such as energy storage, managing demand, and electricity rate options.

Panellists were asked to divide 100 points among three potential investment options for Hydro. Ranking first was upgrades and additions to existing hydroelectric facilities. Ranking second was wind turbines. Ranking third was combustion turbines.

For the most part, results are consistent across demographics. That said, men assign a higher average number of points to upgrades and additions to existing hydroelectric facilities than women (50 versus 40 points) while women allocate a slightly higher average number of points to the other options. That said, upgrades and additions are still allocated the highest number of points across all segments.

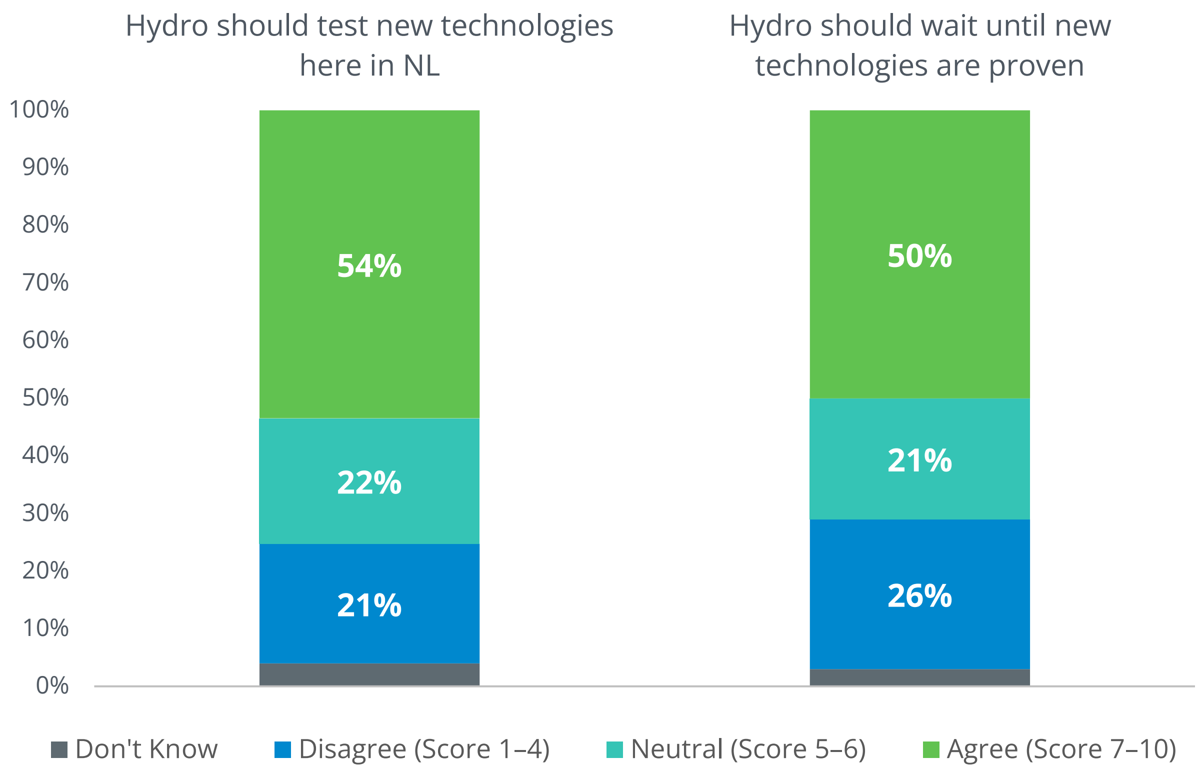
MOST PREFER INVESTMENT IN EXISTING HYDROELECTRIC FACILITIES FOLLOWED BY WIND.



Q. We want to know which of the follow options you think Hydro should invest in. You have 100 points to share between all three factors. The more points you give to an option, the more you think Hydro should invest in it. (n=451).

Technology is rapidly evolving. We know new technologies that can help generate or deliver electricity to customers will continue to become available to us over time. We asked residents at what stage should Hydro consider using new technologies to supply power to customers; the response was divided. While the question wasn't mutually exclusive, testing new technologies has a slight edge over waiting until new technologies are proven. In Labrador, 70% agreed in investing in new technology compared to 30% waiting for technologies to be proven.

DIVIDED ON TESTING NEW OR USING PROVEN TECHNOLOGY



Q. To what extent do you agree or disagree with the following statements? (n=1,667, 10-point scale).

Combustion Turbine

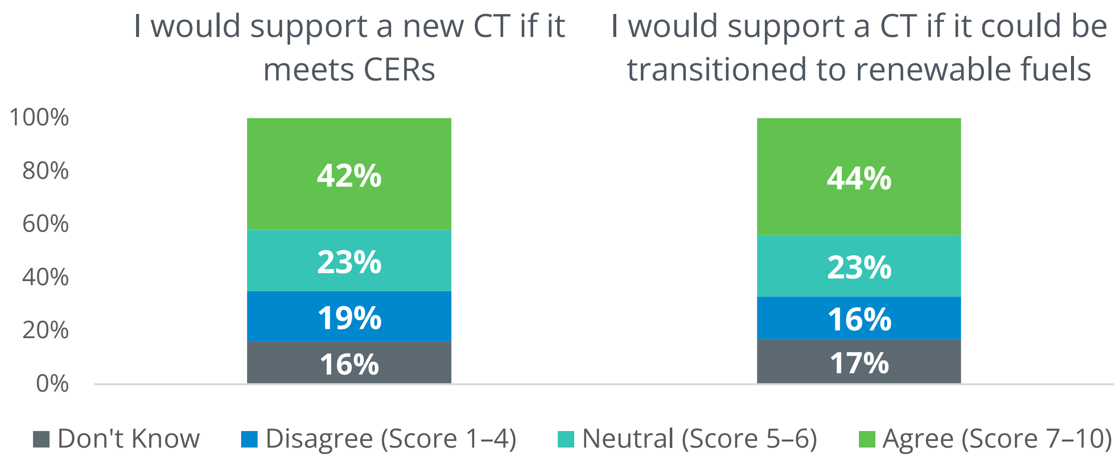
In some areas of the province, we use combustion turbines (CT) to back up existing hydroelectric systems. Across the country, many provinces are building CTs to provide backup generation as well as added capacity for times when demand for electricity is high. In areas with wind generation, they are also used to provide electricity when there is no wind. CTs convert fuel to electricity. Many currently use fossil fuels, such as diesel. In the coming years, many will be able to use renewable fuels when such fuel becomes readily and reliably available. We have been studying how and if an additional CT could be used in our system to meet the electricity needs of customers.

31% of residents had heard of the Combustion Turbine Study

Hydro would only consider a combustion turbine if it is confirmed to meet Canada's Clean Electricity Regulations (CER) and had the lowest impact on customer rates.

We asked residents if they would support the use of a CT in these scenarios. While response leaned toward support, there was also some neutrality, disagreement and uncertainty about the use of a CT.

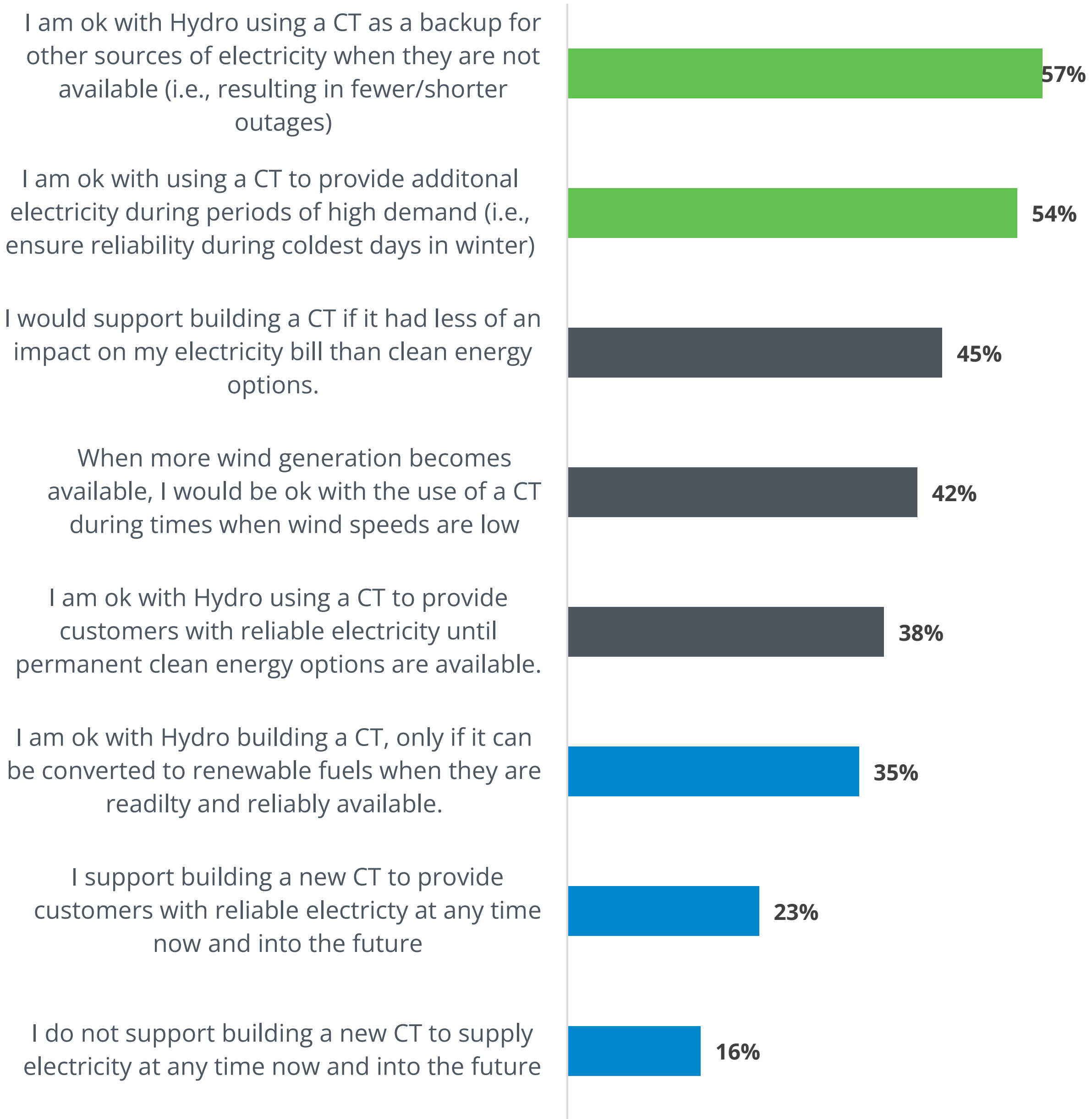
SOME SUPPORT FOR A COMBUSTION TURBINE



Q. To what extent do you agree or disagree with the following statements? (n=1,667, 10-point scale).

We asked some follow-up questions to our Feedback Panellists to indicate whether they agreed with a series of statements related to CTs. A majority agreed with two of the statements, namely that they are okay with using a CT as a backup for other sources of electricity when they are not available and they were okay with the use of a CT to provide additional electricity during periods when demand is high. Agreement with most other statements ranged between 35% and 45%. Just 16% said they do not support building a new CT to supply electricity at any time now and into the future, while 23% said they would support building a new CT to provide customers with reliable electricity at any time now and into the future.

WHEN IS A COMBUSTION TURBINE AN ACCEPTABLE OPTION?



Q. To what extent do you agree or disagree with the following statements? (n=1,667).

Open-Ended Comments (Open Survey)

During the initial open customer survey, residents were given an opportunity to provide additional comments, with half of residents offering comments.

Topics	Percentage that added a Comment about the Topic (n=1,667)
Concerned about rate increases (general)	**31%**
Shareholder profits are high enough/pay for upgrades with profits	**10%**
Infrastructure reliability/maintenance concerns	**8%**
Executive bonuses/compensation concerns	**6%**
Muskrat Falls mentions	**4%**
More support for alternative energy sources	**4%**
Long-term strategic planning/skepticism towards Hydro's future plans	**3%**
Other provinces shouldn't benefit more/pay lower rates	**3%**
Critique of government policies/practices/government/taxes should pay for upgrades	**2%**
Critical of the survey	**2%**
Critique of management practices	**2%**
Critical of electric vehicles (e.g., unreliable, expensive, worse for the environment, etc.)	**2%**
Environmental responsibility/climate change concerns	**2%**
Net-zero is unrealistic/fossil fuels are essential	**2%**
Climate change is a hoax/tax grab	**1%**
Importance of economic development	**1%**
Net metering/selling electricity back to the grid	**1%**
More focus on energy efficiency/energy efficient products	**1%**

Open-Ended Comments (Panel Follow Up)

During the follow-up customer survey, electricity panellists were also given an opportunity to provide additional comments, with 43% offering comments. The most predominant, offered by 2 in 10 (18%) reflects rates. All others were suggested by 4% or fewer. However, it should also be noted that 12% of residents commented on clean energy solutions.

Topics	Percentage that added a Comment about the Topic (n=451)
Concerned about rates	**18%**
Invest in green/renewable energies (unspecified)	**4%**
Lower shareholder profits/management salaries	**4%**
Ensure reliable electricity/reliable infrastructure	**4%**
Increase investments/infrastructure in hydroelectric power	**3%**
Consider using/investing in wind energy	**3%**
Consider using/investing in solar energy	**3%**
Seniors are struggling/need senior's discounts	**3%**
Get rid of fossil fuels/systems that use fossil fuels	**2%**
CTs should only be a backup to other sources of renewable energy	**2%**

Your Comments

(We read every one).

We really appreciate that many of you took time to share additional thoughts we us. While your feedback is summarized in the report, in the following pages we have also included many of your comments with responses to some of the questions that were asked.

Note: Comments have only been edited for punctuation, spelling, and to remove abbreviations.

We identified 10 themes of conversation.

1. Customers are concerned about the cost of living, particularly for seniors.
2. Customers prioritize the lowest impact on electricity rates.
3. Reliability is non-negotiable, but customers do not want to pay more.
4. Customers recognize we have a reliable system from renewable sources.
5. There is a lack of trust in utilities and misinformation about corporate policies.
6. Muskrat Falls has not been forgotten.
7. Many do not feel informed enough to offer an opinion on some topics.
8. Polarization on climate action and the need for clean energy.
9. Most agree we need to prepare for growing electricity needs.
10. No consensus on options for new sources of electricity.

Cost

Cost of Living

- *The average NL resident is struggling with the cost of living, please try to keep rates as low as possible for as long as possible while providing a reliable system.*
- *People can't afford higher electricity bills right now so any investment which would raise rates should be put on hold until inflation has stopped and prices have returned to 'normal'.*
- *Rates are key. We need to be respectful of the dwindling capability of customers to pay for all things demanded of them as home/business owners. If costs keep rising, the customer suffers.*
- *Customers want reliable electricity at affordable rates. Period.*
- *Hydro rates are too high. Harder to afford to pay hydro bills even when using all best practices to reduce my energy use, such as washing in cold water, programmable thermostats.*

Least Impact on Rates

- *I think the burden of rising utility costs in conjunction with everything else across the board becoming more expensive requires any investment to be heavily scrutinized to reduce the financial impacts on customers while maintaining quality service.*
- *My only concern is, whatever system is used, what are the rates going to be like?*

Customers are very concerned about rates. We hear you, and that's why we have to consider all options when we need to invest again. We are working hard to keep the cost to our customers as low as possible.

Jennifer Williams,
President and CEO

- *Whatever is done, needs to have the least amount of impact on prices.*
- *More of the decisions being made need to be based more about the financial cost to the consumers rather than the rush to get new and more efficient means of supplying sustainable energy for us. Yes we need to think about a greener future but with the current state of our economy and the financial burden on the struggling consumer, the cost needs to be minimized to the end user. There's no way to sugar coat that. We are struggling enough as it is right now.*

Vulnerable Communities

- *Being a senior, I worry about the cost of heating our home in the near future. It would be great if there was a way of reducing the cost for seniors like a senior's Rebate.*
- *Electrical rates need to be held and not increased as the cost of living is putting a high financial strain on the most vulnerable people within our province. As a senior I am very worried about ever increasing costs that are putting extreme burdens on the elderly and low income populations.*
- *Considering senior citizens' long history of paying for electricity, it seems fair to offer them a reduced rate once they turn 65, especially if they reside in their own homes.*

Fairness

- *"Everyone" on the NL grid should bear responsibility for upgrading, and costs associated with maintaining the system equally (other provinces etc.).*
- *If it's owned by the people, why do we pay some of the highest rates in Canada and why are we taxed on a necessary service such as this.*
- *All household users of electricity should pay the same rate for electricity no matter where the electricity comes from. If upgrades are needed, everyone who uses electricity should be paying for it.*
- *Customers on the Labrador Interconnect system should have to pay 13.26 cents for electricity, the same as everyone else. As opposed to just 3.15 cents. If they have access to electricity, then we should not have to suffer increased rates to compensate for their steeply discounted rates. While it does cost more to live in certain areas, they are compensated for such. Whereas plenty of people on the island are isolated and have a high cost of living, but receive no such compensation.*
- *I live on the northern peninsula and we should have the same rate per KWh as most of Labrador. 3 cents per KWh. We pay 13 cents per KWh which is just too much.*
- *Perhaps consideration should be given to charging those people who live in remote areas more for their power. To get reliable power to them costs more yet we are all saddled with the extra cost. If you want to live in remote areas, it's more expensive. The majority of your expenditures should be concentrated where the majority of your customers are based and will benefit.*

Reliability

- *Reliable power should be our priority.*
- *Reliable electricity supply is very important, above all other considerations.*
- *Great progress has been made on reliability which was sorely needed. Don't drop that as one of your imperatives as you plan for these other priorities.*
- *Comparing reliability of Hydro systems to others in Canada, Hydro is already well in front of the pack with regard to outages.*
- *Nothing is more important than reliability and affordability. If this includes renewables and/or wind, that's fine. But, if these options are not a proven, safe bet, I'd rather go all in on the Combustion Turbine.*
- *Newfoundland Labradors Hydro grid is spread over a vest area, nothing but the very best components should be used giving our harsh climate conditions and regular preventive maintenance carried out to ensure less downtime.*
- *Hydro has and will have sufficient reliability. You need to start building more capacity and embracing new technologies.*
- *Using new technologies should only go ahead when they are cost effective and have been proven to 100% reliable.*
- *Do not rely totally on software, please look at override systems, too much software and reliance on it will result in many outages in the future.*
- *I have no confidence in your ability to restore power in the event the Labrador Island Link goes down. Especially if the damage is on the Great Northern Peninsula.*
- *Why is there only one power transmission line from Muskrat Falls? You talk about backup systems but if there is a catastrophic failure of the single power line carrying the energy from Muskrat Falls it would be a disaster for the province. We need a better backup and at least one more island based generation similar to the capacity of Holyrood.*

Clean Energy

- *I am a proponent of clean energy, but are we not already a leader? 92%+ power comes from Hydro.*
- *I do support making things better for the environment but not at an unreasonable cost and risk to our collective well-being. The industry has to figure out how to use the cleanest energy available while guaranteeing reliability and affordability.*
- *I am all for clean energy, but I want to see it done in a way where grants and funding are utilized so that the people don't pay the price. We pay enough already.*
- *Green energy has been on the horizon for a long time, and Hydro has a responsibility to adapt without having massive effects on the end consumer.*
- *The effects of climate change are real and happening, and we are decades late in adoption. NL has huge potential to continue to be a leader in this space, via hydro, wind, and tidal power.*
- *Invest in generation that doesn't rely on any type of fuels. Cost of fuels will impact customer prices and there are fluctuations in those costs.*
- *Renewable energy is the future and all areas of NL need to be able to access clean, reliable energy.*
- *I understand the need for clean energy, but we also have to be able to afford to live. The cost of everything is going up and salaries are not.*
- *Clean energy will be more popular when it's affordable.*
- *A change in government would likely immediately change "climate action." I think it's premature to make these decisions to go "greener" given the unstable political landscape.*
- *NL's impact on climate change is negligible. Newfoundland and Labrador have done our part to green the grid and it has cost us. Looking at our place in Canada, there are many other things that need to be done in jurisdictions much larger than ours.*
- *Don't be duped by the environmental movement to rush to convert to other forms of energy. We didn't get here overnight and we're not going to get out of fossil fuels overnight. A slow and steady planned sustainable approach is best for everything.*

- *I do not really care at this point about the Federal Government trying to get us to net zero. I think it's unrealistic and honestly ineffective. Canada is not a leader in producing the pollution and even if every person in Canada stopped using fossils fuels today, there would be little impact on world pollution. In fact, it upsets me that our Federal Government has this mandate instead of advertising our ethically produced, environmentally managed fossil fuels!*
- *I do not support clean energy at any cost.*
- *Use clean energy whenever possible.*
- *Get off fossil fuels as soon as possible.*

Electrification

- *Using clean(er) sources of energy and investment in local infrastructure to support adoption of cleaner technologies (e.g. electric vehicles) will have a positive impact on the environment while creating economic opportunities.*
- *Support enhanced basic insulation for homes and commercial buildings.*
- *I'm not a fan of "all electric" and don't see how it will save the environment. What will happen when all these batteries fail?*
- *After darkNL, we installed a radiant propane fireplace for heat and changed stove from electric to propane. Some of my colleagues who have installed mini-splits and use their back up heat only during cold bursts have electric bills higher per month than my electric/oil and propane combined.*
- *Subsidies to clients wanting to convert to greener energy are cumbersome to access. Why are they limited to people only converting from oil? People need funds for energy assessments and upfront costs, barring it to persons on low incomes.*
- *Need more reliable EV charging infrastructure. The goal should be for every 100 KM of highway/major routes [there is] a charging location with 8 stalls at 250 KW/h minimum per stall (Use batteries if you have to bump up available power per location). Yes, this is a ton of money, but so was Muskrat!*
- *Make EV charging stations available on the Trans-Labrador and Southern-Labrador highways.*
- *Accelerating rollout of highway fast chargers will accelerate EV ownership.*
- *The concept of electric cars is fine if you live in the Avalon but for outlying communities and for people travelling across the province who don't want to take two days to get to Port Aux Basques, it's not realistic.*

- *Car charging stations should be paid by the users and not everyone.*
- *There is too much controversy over electric vehicle safety and sustainability. I don't believe in electric vehicles nor would I ever buy one. Therefore, I don't believe NL Hydro needs to jump the gun on.*

Options/Growth

- *The technologies being evaluated for the next 10-20 years should be stable, proven technologies that can be brought on stream within a reasonable amount of time and for as little cost as possible.*
- *I believe NL Hydro is the backbone of our power and should be enhanced at every opportunity. A second DC Labrador Link in advance of and connecting the wind farms on the west coast. With the Churchill Falls power becoming available in 2041. NL Hydro has an opportunity to become fully flexible with the full potential of a world class electrical grid.*
- *Hydro will need to focus more strategically on investments with a blend of energy solutions. Traditionally and presently NL Hydro continues to chase load growth which needs to change. Planning for things like wind, battery energy storage, etc. needs to be considered for better reliability and less dependency on diesels. Current culture is concerning with regards to the numerous studies and the focus on the story-line, more action is needed to move the needle on the tactical decisions and needed improvement, before it is too late.*

One of the key lessons from the Muskrat Falls inquiry was to ensure more upfront planning and supporting evidence was gathered prior to moving forward with any new applications. That is exactly what we are doing—we have explored every potential solution and will continue to fully vet options before submitting applications to our regulator.

Jennifer Williams
President and CEO

Hydroelectric

- *First, immediately invest in the medium, small and mini hydro sites that are not currently developed on the island of Newfoundland. The development of even a small portion of the available medium/small/mini hydro resource will negate the need for combustion turbines and large windmill farms. Hydro is a known technology, it is your forte. Most of the new hydro plants will add to the base load capacity.*
- *We have good infrastructure now with our hydro-electric facilities. Invest in maximizing their potential before we develop new sources. The cost of heating my home is becoming prohibitive. Keep costs down while maximizing Hydro!*

- *Between Muskrat and Churchill Falls, we have all the clean energy we could ever use with enough to sell for profits to all citizens. Instead, Hydro thinks the costs to explore other ways to generate power belong to its customers.*
- *What are the chances that results of an environmental study will prevent the expansion of hydro-electricity in the Bay d'Espoir area?*
- *It's time to find a cost-efficient [way] to develop more hydro-electric power from our water resources.*
- *Enhance and develop on island hydro sources. Do not waste any time or money on wind or solar or renewable combustion.*
- *Hydro power is not green energy. It's ecologically damaging. OTHER approaches must be pursued (solar, wave, etc.).*
- *The Labrador Island Link needs to be maximized and new power from Labrador such as Gull Island be explored more. The 60 year old thermal plant needs to be phased out to help reach net zero goal.*
- *Consider Gull Island, increase capacity at Upper Churchill & for god's sake fix the Muskrat Falls transmission issue.*
- *Big hydro projects may be greener than consuming fossil fuels but come at a cost to the environment that we give insufficient consideration to.*
- *All of the electricity manufactured in Labrador using the Mighty Churchill should be enough to run Newfoundland and Labrador and more besides. I don't understand why we would need a CT.*

Wind/Hydrogen

- *Hydrogen is moving forward quickly, I would much prefer to go in that direction to break free from fossil fuel completely for at least heating our homes. I am against wind turbines as they cannot be disposed. They do not rot in the ground and have to be buried. They are noisy and not biodegradable.*
- *Very hopeful for wind energy in this province, makes sense to use what we are known for. There is skepticism that the average consumer will see benefits, though.*
- *There needs to be a shift to renewable energies but wind isn't necessarily the solution, especially since residents oppose it.*
- *Keep wind turbines out of NL.*

- *Wind is not reliable and costly because you still need back up power such as combustion turbines. I would focus on sources of energy that are very reliable and compliment the 93% of renewable energy we already use. We need to build something that generates power 100% of the time, which unfortunately is not wind.*
- *Wind turbines have a relatively large carbon footprint to build and have a small unreliable power output. Stop wasting time and money on wind energy.*
- *Let's get to renewables faster. Wind energy in one of the windiest provinces in Canada should have started years ago.*
- *Why did you not follow through with the plant you built in Ramea 25 years ago and are leaving to rot while the rest of the world is exploring hydrogen?*
- *I believe an ammonia combustion engine are not that far off in the future. The wind power makes ammonia that can be stored and then used as fuel for these generators and ferries of NL.*
- *Be wary of these hydrogen/wind farm private companies requiring 80 MW of power.*
- *I am concerned that the Wind Energy Projects will cause Power Rates to increase. Also, how come the Ammonia Plant can't be put in Goose Bay to buy cheap power from Churchill and help keep rates down in Newfoundland?*

We consider all potential sources of supply to meet demand for electricity. Source selection is based on delivering electricity at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service. We must ensure the next solutions and proven reliable. We expect wind generation to be more prominent very soon and will examine other sources in the coming years.

Jennifer Williams
President and CEO

Combustion Turbine

- *As long as there are no increases to the consumer, I'm ok with CTs.*
- *The fact that so little of NL's energy comes from fossil fuel generated electricity gives us some wiggle room to implement technologies, such as CT, in order to lower taxpayers' electricity bills while still making substantial contributions to national GHG reduction targets.*
- *Please, for the love of all that's holy, stop talking about building new turbines. Negotiate power purchase from the Upper Churchill if necessary, but stop talking about "renewable" fuels. Get out of that headspace entirely. Please.*
- *A CT would be a good option for reliable backup supply. We do not yet know how reliable the feed from Labrador is and extreme weather could have an impact at some point in time.*

- *I do understand using CTs to offset during high demand/low supply, but I think this idea of converting to use renewable fuel sources in the future is more spin and politics than something that is sustainable.*
- *You can't say you're dedicated to meeting the no emissions by 2035 standard and act like a combustion turbine meets that mark. It's not that much different than a gas powered generator.*
- *Any new CTs installed should have synchronous condenser capability.*
- *CTs have a purpose as backup or peaking units. Not for regular service. I am ok with longer outages if it comes to that as long as they are fewer.*
- *Convert Holyrood to a CT and use the renewable fuel from the refinery at Come-by-chance. Seems like a win-win for the short term.*
- *I don't understand the focus on CTs for the province. Carbon-neutral fuels will always be more expensive than instead focusing on renewables such as wind and hydro.*
- *I think Hydro needs to invest in adding additional renewable power generation first, probably with more wind generation, before going too far down the CT path. I understand that this kind of investment would be more expensive in the short term, since CTs are cheap, but we as a province need to be more forward thinking.*
- *We need to discover or plan into a safe electrical grind. CT though can generate large quantities of power, the safe and risk to workers is high.*
- *Local emergency back up in form of combustion turbines for loss of LIL makes great sense. New hydro for load growth with wind and energy storage as technology improves*
- *Combustion turbines are known to have a negative impact on the environment, it does not matter if some people disagree. You are the authority to do what's best for people, today and in the future.*

We made a commitment that we would examine all potential new sources of electricity, especially since we know customers are concerned about how this potential projects impact rates. So we must consider how a combustion turbine that can use renewable fuels could be integrated into our system and provide added reliability.

Jennifer Williams
President and CEO

Other Renewables

- *Has NL Hydro considered solar panels? On a large scale basis?*
- *I believe that wind and tidal power are major underdeveloped resources that we have, and am dismayed to hear of protests and NIMBYs complaining about turbines. I wish these projects would go full-steam ahead.*
- *I do not believe the battery power storage is the long term solution and an alternative fuel source such as hydrogen etc. will surpass battery technology in the long term.*
- *Solar energy does not seem to be on the radar in NL. It is a technology which is advancing exponentially. It's time we educated people on this.*
- *Rather than CT technology, storage of electricity in the form of battery banks is a suitable alternative.*
- *I would like to see the introduction of tidal energy infrastructure, such as the technology from Eco Wave Power.*
- *Battery electric storage and/or pumped hydro storage instead of CT.*
- *You need to start looking at pumped hydro and investing in other technologies that can correct for the so-called "unreliable" clean energy technologies available.*
- *Consider the use of tidal-power, and piezo-electric systems for localized systems.*

Non-Renewables

- *There are large reservoirs of natural gas off our shores and accessible by existing offshore infrastructure, however we have no capacity to transport it onshore or produce power from it. Invest in hydro, nuclear, and (maybe) natural gas.*
- *Biggest contributor to Hydro carbon emissions is Holyrood, decommission it as soon as possible.*
- *Holyrood badly needs upgrading so that it can provide generation in case of interruptions of supply as it was originally intended.*
- *Hydro should decommission Holyrood. A combustion turbine for peak and back-up is acceptable - if it is the best and most financially prudent decision. Remote communities that are not connected to the grid will have to stay on fossil fuel generation, unless a sound business case can provide another viable and cost-effective option.*
- *Holyrood thermal generating station is an asset that needs to remain in place for many years to come. An additional combustion turbine would be beneficial.*

- *Invest into nuclear systems for power, it would be cleaner and more cost effective than the LIL that barely works.*
- *BioFuels are highly inefficient and susceptible to microorganisms degradation and contamination. CO2 is essential to sustaining breathing for we mammals and I would really appreciate it if the Mob would stop calling hydrocarbons "fossil fuels", their ignorance is only exceeded by their hubris.*

Transmission

- *There needs to be an assessment done on trees adjacent to power lines that are in danger of having a negative impact due to wind storms as our weather patterns seem to be increasing in intensity as years go by.*
- *Power line access is quite extensive, pairing with small private partners, or more work in promoting bi-directional supply systems (end users with solar panels as an example) to strengthen certain areas. Think outside the framework of mega-projects.*
- *All power lines should be set underground here in NL; it's so windy and also so beautiful here it's a shame infrastructure has not supported more underground electrical lines.*
- *The Labrador Link is not even up and running we are paying for something that is garbage and it will never work, but we continue to pay.*
- *More investment needed to better secure existing secondary transmission lines against tree overgrowth especially in rural areas. Extremely long wait times for work orders to be actioned.*

Customer Options

Demand Management

- *Hydro should investigate the use of variable rates to encourage users to use energy in off peak hours thus reducing demand in peak hours. This should be incentive-based, providing lower rates per KW/h for off peak times, but should never implement higher rates during peak times.*
- *Emphasize managing peak demand by considering differential rates at different times of day. Also consider incentives for customers who keep their peak use low.*
- *There is not much about energy efficiency or demand management—maybe that comes later in this process.*

The use of dynamic rates, such as time of use or critical peak pricing, is being studied jointly by Hydro and Newfoundland Power. A move to dynamic rates will require a significant investment in smart metering infrastructure. Hydro will continue to work closely with Newfoundland Power on conservation and demand management initiatives through our takeCHARGE partnership.

Jennifer Williams
President and CEO

Net Metering

- *I would like to be able to sell excess solar energy back to the grid like other provinces.*
- *We need a push for people to generate their own renewable electricity and to be able to sell the excess to each other, providing a marketplace for energy to be generated locally, stored locally, and bought and sold by everyday people seems like the only scalable option.*
- *People need to become more electrically self-sufficient and at the same time renewable fuels are needed pronto for things like the CT.*
- *Hydro should promote or encourage residents and businesses to invest in net metering to help produce electricity. If a fraction of the houses in the province installed net metering this would help with reducing the need to add massive capital investments in major projects.*
- *There should be more incentives for private citizens to have their own personal wind turbines/solar panels and perhaps sell back to the grid.*
- *Let customers generate their own electricity via wind or solar.*

Labrador

- *As a resident of Labrador, a major source of power for the island and other locations other than Labrador, it irks me that the Island is the focus of surveys. What about us? Why are we left out of the option of cleaner and/or more reliable sources of power?*
- *Further development of hydroelectric power shouldn't proceed without greater attention environmental issues is essential in the continued development and expansion of wind energy*

To our customers in Lab West, we understand your frustration with annual outages. We recognize that the single line providing your electricity wasn't built to today's utility standard. After acquiring the line in 2016, we began the annual maintenance program to ensure the line's continued reliability. We are actively exploring options to address the impact of these outages.

Jennifer Williams
President and CEO

Outages

- *There is absolutely zero excuse for the number of outages in Goose bay, and we all know you have zero plans on investing to improve, as head office there says outages are supposed to be expected and pretend 10+ 12 hour outages per year is acceptable. Whatever you are wanting to develop in Labrador isn't welcome.*
- *Yes, why is it every single year multiple times a year Labrador west has to come off power for 8-12 hours for "upgrades" hydro does not do this to any other communities if this is a system issue please fix it, if it's a worker safety or training issue fix it.*

Diesel Reduction

- *Those of us who require fossil fuel for electricity generation should be subsidized or Hydro should extend power lines to connect us to the grid.*
- *Why a new super diesel plant in Labrador when the Island Transmission line is in our, Labradors, backyard? All customers in the province should be paying same rates? Labrador customers will never have our full voices heard because of our numbers, so although this survey is good to see it will do nothing for myself, my family, community and business in Labrador.*
- *I am not in favour of a super diesel plant in Port Hope Simpson.*

Upper Churchill

- *I believe the NL government and Hydro should continue to work together to develop a feasible plan with the Quebec Government & Hydro Quebec for development of the Churchill River.*
- *2041 take all the power from Churchill Falls and use it to electrify NL. No negotiation required with Quebec.*

> The Churchill Falls facility is an incredible and unique asset and it will continue to play a very important role in this Province's energy future. We are incredibly proud to be at the table to discuss its future.
>
> Jennifer Williams
> President and CEO

- *Bypass Quebec. They have gotten more than their share.*
- *Negotiate a better deal with Quebec on all hydro options.*
- *I think we should complete the Gull Island generation project since the Churchill River is already exploited.*
- *Our province is burdened with debt. I would like to see more money go into development in Labrador (Gull Island) and use the spill over from Muskrat Falls to add more kilowatts to the grid as opposed to more money for shareholders!*

Muskrat Falls

- *I have ongoing concerns about Muskrat Falls, which we know continues to experience equipment failures and I don't have a high degree of confidence in Hydro's ability to address the issue—and in a timely manner. I fully expect that, at some point, we will experience possibly lengthy periods without electricity. The rosy picture presented by Hydro's CEO does not persuade me that "all will be well".*
- *The fact is we as a province will be paying for Muskrat Falls for so long that investing in expensive additional renewable power makes no sense.*
- *We were led to believe that Muskrat Falls was the answer for all our electricity needs. Now you guys are trying to say we need other sources of electricity for our Newfoundland and Labrador customers?*
- *Why can't we use Muskrat Falls to produce hydrogen, instead of wind turbines? This would be a major help to keep rates down for Newfoundland and Labrador?*

- *Also, with the mess that Muskrat Falls became Hydro needs to be hyper vigilant to ensure we don't get a repeat. The lack of oversight and the gross mismanagement of that project should never happen again.*
- *I know that NL Hydro has invested a massive amount of money to bring Muskrat power to the island. However, I'm not comfortable with the reliability of the system used to supply this power. Because of this I have serious concerns about future investments in future upgrades to electricity generation. More careful consideration must be given to alternative methods and production costs.*
- *Acting quickly in anyway has proven over and over again to result in a negative outcome. Any decision made by NL Hydro and our government needs to be well researched and well thought out or NLer's will be paying the cost (like we already do thanks to the Muskrat Falls hell).*
- *I am leery of any new plans for expansion or transition after the Muskrat Falls disaster.*
- *Once there is accountability for NALCOR and Muskrat Falls, I will consider the idea that NL Hydro may be able to help NL*
- *We have one of the most expensive rates in the country. Now you are selling power from muskrat and making large returns, why not give some of that back to the NL residents by means of a lower power rate and help make it affordable to live here.*

Muskrat Falls was a solution to meet the demand forecasted at the time. We recognize there were many challenges bringing that facility online—and that there are still concerns today. Today, we are now seeing value from the project, with the facility performing above the national average for availability. Now, we are again looking to the future, at what will be needed for the next ten years and beyond. Our job doesn't stop, we keep planning, making one decision at a time to keep up with customers' electricity needs.

Jennifer Williams
President and CEO

- *I thought the investment in Muskrat Falls would supply the additional electricity needed in NL.*
- *Why is there talk of producing more energy when Muskrat Falls will produce way more than Newfoundland needs?*

- *When you were considering blazing new trails? Always keep a picture of the upper Churchill and muskrat Falls signing ceremonies as a reminder to never let giveaways and cost overruns determine the fate of our residents. Be diligent in the future economic potential of selling power to the rest of Canada and the United States above and beyond what's been sold now to benefit our province. We have amazing clean hydro energy potential in this province that's untapped. And again, and always* remember that the residents of *Newfoundland and Labrador will never forget the giveaways, and the cost overruns of Churchill Falls and Muskrat Falls... be smarter and do better.*

Corporate Policies

- *Accountability for executives is paramount and bonuses should only be given when a project is on time and on or under budget.*
- *Keep rates down and stop wasting money on bonuses and other perks for executives.*
- *Eliminate corruption and corporate handouts and make power clean and affordable. Energy companies should not increase their profit margins.*
- *I'd like to see NLH provide details of the last human resource review, and when another independent review is planned.*
- *Hydro should have a "people representative" to address these issues with the government.*
- *580 million in profits in 2022, rates for customers should not be increasing. Our costs are increasing because of poor political deals.*
- *Cut back on the EXTREME bonuses into the millions of dollars. They do not need to be that high.*
- *Executives get paid too much, and why would they receive bonuses.*
- *How much is the compensation for the executive and shareholders and why are we paying them such an amount considering that they contribute absolutely zero to the output and maintenance of the company's electrical generating equipment?*
- *Hydro needs new management. The Labrador Island Link is an example of yet another failure that proper engineering practice would have revealed. Any future large scale developments in the generation side of Hydro need to be completed by outside experts. There is no longer confidence that it can be done with the personnel at Hydro and their recent statements to the public have shown they have not learned from pass mistakes.*

- *Hydro needs more staff position and to get away from over-priced and ineffective contractors in many areas. Pub headcount process really needs to be reviewed and changed. Finally, the outsourcing of consulting, design and engineering work is making our capital program more expensive on rate payers than it should be. There are many opportunities but, it seems many have the blinders on and there's no unified view or appearance of working together as a company. Lots to be done, and it would be nice for someone to talk about what we plan to do and actually get moving on these and other initiatives.*

Your trust is important to us, and we know that is something we must earn. We are a continually improving organization – working hard on your behalf. Yes, in the past two years, we've had a strong financial performance—a turning point. Our cost cutting measures, including the reduction of executive positions by half and elimination of bonuses, saved $19 million. This is good news for our only shareholder—you, our customers, who benefit directly from our success.

Jennifer Williams
President and CEO

- *Hydro's image and presence could benefit from giving back and supporting community programming such as schools, municipalities and extracurricular activities/facilities. Especially in communities that feel the negative impact of hydro generation (erosion, flooding of natural waterways, destroyed natural animal habitat, high mercury levels etc.). Communities such as bay d'Espoir receive little to no support, recognition or compensation for such impact. Your corporation's impact on the environment is more than carbon emission.*
- *I believe there is too much focus on profit rather than reliability. I understand that reliability costs money however there is no way I can agree with the profits you're reporting.*
- *I think executive salaried positions at NL Hydro should be cut drastically and their annual bonuses be used to invest in greener energy solutions.*
- *I would like to first thank NL Hydro for your work on Muskrat falls and keeping us fed with reliable electricity. It's no small feat and I understand the magnitude of the job. I do however ask that an appropriate amount of caution be taken when undertaking new projects or "investments." For the duration of my adult life, the narrative has been that we need to pay more for the system to be more reliable and have enough capacity. We have endured increase after increase in order to fund the upgrades and I feel we have indeed seen an increase in reliability. But we need a break on rate hikes. It can't be a constant March to the PUB looking for more. Sometimes a company can invest profits rather than going to customers to foot the bill every time. There are profits being made, the reports are available. Rate payers have had enough from large companies asking for more while posting reasonable profits. Hydro is not the only one, but you are doing more than most.*

Energy Marketing

- *I would like to see Hydro charge enough for power being transported out of province to ensure the citizens of NL are not stuck with rising power costs*
- *We are going to sell power to Nova Scotia, Quebec, and New England states, so why would we simply just not sell. Then we would have what we need.*

Communications

- *I am not knowledgeable in this to provide a responsible reply.*
- *Before making better decisions, I feel more information will be needed, also environment impacts will need to be considered as well.*
- *A lot of these questions assume knowledge of current demand, projected need and reliability of the current electrical systems.*
- *NL Hydro, in conjunction with the Provincial Government should be more proactive in educating citizens and make more info readily available, for example, what will be the impact on NL in 2041 with the end of the Churchill Falls agreement? What is the long-term plan or vision, say 10 to 25 years out? Where can I find this plan? People are interested in learning more without any spin; even this survey has shown me that I don't know enough about the subject (combustion turbines?). What about other efficiencies, i.e. street lights, transmission, etc.*

Our industry is complex. We try very hard to be transparent and accessible to the public, but we know there is more we can do to help people understand the electricity system, the decisions ahead of us, and why it all matters. Our business is sometimes complicated to communicate effectively, but we are committed to do better and taking action to improve communication and provide more opportunities for public education and engagement.

Jennifer Williams
President and CEO

- *I believe expectations are set too high and that comes with a significant cost. If reliability was balanced more responsibly in an effort to reduce costs and communicated better to the general public, the majority of customers would be fine with periodic power outages from time to time as it is considered normal in other jurisdictions.*
- *You should hold public forums around the province from rate holders.*

- *Also believe their isn’t enough readily available information on if we are exporting electricity via maritime link or to anywhere else in North America, could revenue from the selling of electricity be used for upgrades versus rate hikes on the public.*
- *Some of these questions are difficult to answer, given that the average individual has little knowledge of the working systems and requirements of the hydroelectric systems in NL.*
- *I'm surprised this didn't include checking with the population for input on various renewable energy sources. Be it wind, tied, or additional water sources, it's very disappointing to me to see a complete lack of share with the public on steps being made to explore sources this should be very compatible with Newfoundland geography, weather, and other natural phenomenon.*
- *More transparency with the rate payers. Put all available information out to the people and let them decide if you are truly looking out for our interests. It's hard to make decisions when even our advocates aren't given all the facts in why you are requesting rate increases.*
- *This is a fairly technical survey, and I'm not sure that a lot of residents will understand many of the questions to do a good job of answering them (myself included).*

Abbreviations

Abbreviations

Term	Definition
2018 Filing	"Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
2019 Update	"Reliability and Resource Adequacy Study – 2019," Newfoundland and Labrador Hydro, November 15, 2019.
2021 Update	"Reliability and Resource Adequacy Study – 2021 Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro (originally filed in March 2021).
2022 Update	Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
2024 Expansions Plans	2024 Expansion Plans - Development Process and Recommendation
2024 Resource Plan	2024 Resource Adequacy Plan
AACE	Association for Advancement of Cost Engineering
ac	Alternating Current
Accelerated Decarbonization	Accelerated Decarbonization Path Scenario
Act	*Public Utilities Act*
Avalon	Avalon Peninsula
BACT	Best Available Control Technology
Bay d'Espoir or BDE	Bay d'Espoir Hydroelectric Generating Station
BESS	Battery Energy Storage System
BESS Study	"Battery Energy Storage System Report – Overview," Newfoundland and Labrador Hydro, September 29, 2023.

Term	**Definition**
Board	Board of Commissioners of Public Utilities
Brattle	The Brattle Group
Braya	Braya Renewable Fuels (Newfoundland) GP Inc.
BTM	Behind-the-Meter
CAA	Capacity Assistance Agreement
CAMPUT	Canadian Association of Members of Public Utility Tribunals
Cat Arm or CAT	Cat Arm Hydroelectric Generating Station
CBPP	Corner Brook Pulp and Paper Limited
CCCT	Combined-Cycle Combustion Turbine
CDM	Conservation and Demand Management
CER	*Clean Electricity Regulations*
Churchill Falls	Churchill Falls Hydroelectric Generating Station
Co_2e	Carbon Dioxide Equivalent
Co-Gen	Cogeneration
Come by Chance TS or CBC	Come by Chance Terminal Station
CPI	Consumer Price Index
CPP	Critical Peak Pricing
CRN	Canadian Registration Number
CSA	Canadian Standards Association
CT	Combustion Turbine

Term	Definition
CT Feasibility Study	“Combustion Turbine Feasibility Study – Overview,” Newfoundland and Labrador Hydro, September 29, 2023.
CT Options Report	"Accelerated Holyrood Combustion Turbine Installation Options Study—Final Report,” Stantec Consulting Ltd.
DAFOR	Derated Adjusted Forced Outage Rate
DAUFOP	Derated Adjusted Utilization Forced Outage Probability
Daymark	Daymark Energy Advisors
dc	Direct Current
DLE	Dry-Low Emissions
DLR	Dynamic Line Rating
Dunsky	Dunsky Energy + Climate Advisors
EA	Environmental Assessment
EC	Electricity Canada
ECCC	Environment and Climate Change Canada
ECDM	Electrification, Conservation, and Demand Management
ECI	Early Contractor Involvement
EHRC	Electricity Human Resources Canada
ELCC	Effective Load Carrying Capability
EM	Energy Marketing
EOI	Expressions of Interest
EOP	Emergency Operating Procedure

Term	Definition
EPCA	*Electrical Power Control Act*
EqFOR	Equivalent Forced Outage Rate
$EqFOR_d$	Equivalent Forced Outage Rate Demand
EUE	Expected Unserved Energy
EV	Electric Vehicle
Exploits	Exploits Generation System
Exploits River Development	Exploits River Hydroelectric Development
February 2024 Public Update	"Clean Electricity Regulations Public Update: 'What We Heard' during consultations and directions being considered for the final regulations," Environment and Climate Change Canada, February 16, 2024.
FEED	Front-End Engineering and Design
FOR	Forced Outage Rate
FTM	Front-Of-The-Meter
Fuel Market Study	"Long-Term Fuel Supply Study," Holyrood," Stantec Consulting Ltd.
GADS	Generating Availability Data System
GDP	Gross Domestic Project
G-ERIS	Generating Equipment Reliability Information System
GHG	Greenhouse Gas
GNL	Government of Newfoundland and Labrador
GJ	Gigajoule
GSU Transformer	Generator Step-Up Transformer

Term	Definition
Granite Canal	Granite Canal Hydroelectric Generating Station
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
Haldar	Haldar & Associates Ltd.
Hatch	Hatch Ltd.
Hinds Lake	Hinds Lake Hydroelectric Generating Station
Holyrood TGS	Holyrood Thermal Generating Station
HRSG	Heat Recovery Steam Generator
HRV	Heat Recovery Ventilator
HVdc	High-Voltage Direct Current
Hydro or NLH	Newfoundland and Labrador Hydro
IAP2	International Association for Public Participation
IRP	Integrated Resource Plan
IIS	Island Interconnected System
kt	Kilotonne
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
Island Pond Development	Island Pond Hydroelectric Development

Term	Definition
LDES	Long Duration Energy Storage
Liberty	The Liberty Consulting Group
LIL	Labrador-Island Link
LIL Power Demand Override	Labrador-Island Link Power Demand Override
LIS	Labrador Interconnected System
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
Long Harbour TS or LHR	Long Harbour Terminal Station
LTA	Labrador Transmission Assets
MCR	Maximum Continuous Rating
MJ	Megajoule
MSHP	Mini-Split Heat Pump
Mt	Megatonne
MUN	Memorial University of Newfoundland
Muskrat Falls	Muskrat Falls Hydroelectric Generating Station
Muskrat Falls Inquiry	*The Commission of Inquiry Respecting the Muskrat Falls Project*
MVA	Megavolt-Amperes
MVAr	Megavolt-Amperes Reactive
MW	Megawatt

Term	Definition
MWh	Megawatt-hour
N-1	N-1 Redundancy
N-2	N-2 Redundancy
NAP	*Network Addition Policy – Labrador Interconnected System*
NB Power	New Brunswick Electric Power Corporation
NERC	North American Electricity Reliability Corporation
NEUE	Normalized Expected Unserved Energy
Newfoundland Power or NP	Newfoundland Power Inc.
NLSO	Newfoundland and Labrador System Operator
NL Utilities	Hydro and Newfoundland Power
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
NS Power	Nova Scotia Power Inc.
NUG	Non-Utility Generator
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
PAC Test	Program Administrator Cost Test
Paradise River	Paradise River Hydroelectric Generating Station
PMBOK	The Project Management Book of Knowledge
Portland Creek Development	Portland Creek Hydroelectric Development

Term	Definition
Posterity	Posterity Group Consulting Inc.
PPA	Power Purchase Agreement
PSSE	Power System Simulator for Engineering
Pugh Analysis	Pugh Concept Selection Process or Pugh Method
Pumped Storage Study	"Pumped Storage at Existing Hydro Sites – Overview," Newfoundland and Labrador Hydro, October 31, 2023.
RAS	Remedial Action Scheme
Reference Case	Expected Load Forecast (or Reference Case Load Forecast)
Reference Question	*Reference on Rate Mitigation Options and Impacts Relating to the Muskrat Falls Project Costs* proceeding
RFI	Request for Information
RFP	Request for Proposals
Rolling 12	Hydro's "Quarterly Report on Asset Performance in Support of Resource Adequacy."
Round Pond Development	Round Pond Hydroelectric Development
RRA Study	The Reliability and Resource Adequacy Study document
RRA Study Review	*Reliability and Resource Adequacy Study Review* proceeding
RS1	Rate Sensitivity 1
RS2	Rate Sensitivity 2
SC	Synchronous Condenser
SCCT	Simple-Cycle Combustion Turbine
SCL	Short-Circuit Level

Term	Definition
Slow Decarbonization	Slow Decarbonization Island Interconnected System Load Forecast
Soldiers Pond TS or SOP	Soldier's Pond Terminal Station
Stantec	Stantec Consulting Ltd.
Star Lake	Star Lake Hydroelectric Generating Station
STATCOM	Static Synchronous Compensator
Sunnyside TS or SSD	Sunnyside Terminal Station
TL	Transmission Line
TOU Rates	Time-of-Use Rates
TransGrid	TransGrid Solutions
TransGrid Study	"Assessment of the BDE–SOP Transmission Constraints TB1817.01.05," TransGrid Solutions Inc., October 25, 2023.
TRC Test	Total Resource Cost Test
TW	Terawatt
TWh	Terawatt Hours
TwinCo	Twin Falls Power Corporation
UFLS	Under Frequency Load Shedding
UFOP	Utilization Forced Outage Probability
Upper Salmon	Upper Salmon Hydroelectric Generating Station
U.S.	Unites States of America
Vale	Vale Newfoundland and Labrador Limited
Vista DSS	Vista Decision Support System

Term	Definition
W	Watt
WACC	Weighted Average Cost of Capital
Western Avalon TS or WAV	Western Avalon Terminal Station
Wh	Watt-hour
Wood	Wood Canada Limited

Definitions

Definitions

Accelerated Decarbonization Island Interconnected System Load Forecast ("Accelerated Decarbonization"): A forecast developed to reflect the range of forecasted Island Interconnected System load requirements that assumes a higher-than-expected load.

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers within the system criteria, taking into account scheduled and unscheduled outages of system elements.

Adjusted Gross Domestic Product: Excludes income that will be earned by the non-resident owners of provincial resource developments to better reflect growth in economic activity that generates income for local residents.

Alternating Current ("ac"): A type of electrical current, in which the direction of the flow of electrons switches back and forth at regular intervals or cycles. Current flowing in power lines and normal household electricity that comes from a wall outlet is alternating current.

Avalon Peninsula: The Avalon Peninsula on the Island portion of the province.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Base Case: The expected case, determined by using the assumptions considered most likely to occur.

Base Load: The minimum amount of electricity required over a period of time at a steady rate.

Battery Energy Storage Systems ("BESS"): Energy storage systems that use a group of batteries to store electrical energy.

Behind-the-Meter ("BTM"): Systems that generate and use energy directly on site without passing through an electric meter.

Beneficial Electrification: Beneficial electrification (or strategic electrification) is a term for replacing direct fossil fuel use (e.g., propane, heating oil, gasoline) with electricity in a way that reduces overall emissions and energy costs for customers.

Best Available Control Technology ("BACT"): One of the pollution control methods covered by the U.S. Clean Air Act that promotes air quality, protects the ozone, and places limitations on emissions.

Bipole Transmission Failure: Simultaneous loss of both poles of a bipole HVdc transmission system.

Board of Commissioners of Public Utilities: An independent, quasi-judicial tribunal constituted under the *Public Utilities Act*.

Bridging Period: The Bridging Period is defined as the period from 2023 to 2030.

Canadian Registration Number ("CRN"): A number issued by each province or territory in Canada by an authorized safety authority for any boiler, pressure vessel, or fitting that operates at a pressure greater than 15 psig (pounds per square inch gauge).

Capacity: The maximum output of electricity a generating unit is providing at one point in time, typically measured in watts, kilowatts, and megawatts.

Capacity Assistance: Contracted curtailable loads and customer generation that can be called on for system support. Capacity assistance agreements are generally restricted in terms of frequency, duration and annual usage.

Carbon Dioxide Equivalent ("CO_2e"): The number of metric tons of CO2 emissions with the same global warming potential as one metric ton of another greenhouse gas.

Class 3 Cost Estimate: A Class 3 cost estimate is an estimate based on preliminary design documentation. The accuracy of the cost estimate varies between less than 20 percent or more than 30 percent of the estimated cost.

Clean Electricity Regulations: The regulations developed by the Government of Canada to provide an early signal to enable each province and territory's progress towards a cleaner grid.

Co-generation ("Co-Gen"): Generation that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes.

Coincidence Factor: The coincidence factor is a measure of the likelihood of the independent systems peaking at the same time. For the Newfoundland and Labrador Interconnected System, it provides a measure of the relative contribution of the Island Interconnected System and the Labrador Interconnected System peaks to the combined Newfoundland and Labrador Interconnected System Peak.

Combined-Cycle Combustion Turbine ("CCCT"): An assembly of heat engines that work in tandem from the same source of heat, converting it into mechanical energy.

Combustion Turbine (also known as a gas turbine) ("CT") : A fuel-fired turbine engine is used to drive an electric generator. Combustion turbines, because of their generally rapid firing time, are used to meet short-term peak demands placed on power systems.

Commissioning: The process by which a power plant, apparatus, or building is approved for operation based on an observed or measured operation that meets design specifications.

Conservation and Demand Management ("CDM"): Describes a range of programs and initiatives to encourage users to conserve electricity and use it more efficiently. It also includes efforts to decrease peak demand for electricity.

Consumer Price Index ("CPI"): The consumer price index is an indicator of the change in consumer prices. It measures price change by comparing through time the cost of a fixed-basket of consumer goods and services.

Critical Peak Pricing ("CPP"): Critical peak pricing offers customers time-varying rates that reflect the cost of capacity during critical peak times. By significantly increasing the rate during that time, customers are incented to significantly shift or reduce demand during the critical peak period.

Curtailable Load: A load, typically commercial or industrial that can be interrupted at the request of the system operator.

Decarbonization: Decarbonization aims to reduce carbon emissions by transitioning away from fossil fuels and embracing low-carbon or carbon-neutral alternatives. It encompasses strategies such as using electricity grids powered by renewable energy resources, energy efficiency improvements, and carbon capture and storage technologies. The increasing deployment of renewable energy sources is a significant driver of decarbonization globally.

Decommission: To take a piece of equipment such as a generation or transmission facility out of service permanently.

Demand: (1) The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated interval of time. (2) The rate at which energy is being used by the customer.

Demand-Side Management (also known as Customer Demand Management): The term for all activities or programs undertaken by the utility and/or its customers to influence the amount or timing of electricity they use.

Derate: Reduce the energy or capacity rating of a piece of equipment to reflect the fact that it can operate only below its original design rating because of site conditions, a deficiency or physical condition. Derating can be temporary or permanent.

Derated Adjusted Forced Outage Rate ("DAFOR"): Measures the percentage of time that a unit or group of units is unable to generate at its Maximum Continuous Rating ("MCR") due to forced outages.

Derated Adjusted Utilization Forced Outage Probability ("DAUFOP"): The probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

Deterministic Analysis: Uses a set of known and fixed system conditions and probabilities (load, forced outage rates, transmission flows, and intermittent generation) to determine system reliability. Deterministic analysis is computationally efficient but does not consider many of the uncertainties present in real-world systems.

Direct Current ("dc"): Electrical current which flows consistently in one direction. The current that flows in a flashlight or another appliance running on batteries is direct current.

Dispatchable Resource: A dispatchable resource is a generation resource that can be used on demand and increased or decreased at the request of operators, according to system needs.

Dry-Low Emissions ("DLE"): A technology that reduces nitrogen oxide emissions that exhausts out of combustion turbines.

Dynamic Line Rating ("DLR"): The active varying of presumed thermal capacity for overhead power lines in response to environmental and weather conditions to maximize load without compromising safety.

Early Contactor Involvement ("ECI"): A procurement process that allows contractors to be involved in the design and delivery of a project from the outset.

Effective Load Carrying Capability ("ELCC"): A metric used to assess firm capacity credit for intermittent generation resources. It is a measure of the additional load that the system can supply with the addition of a generator with no net change in reliability.

Electric Vehicle ("EV"): A vehicle that can be powered by an electric motor that draws electricity from a battery and is capable of being charged from an external source. An EV includes both a vehicle that can only be powered by an electric motor that draws electricity from a battery (all-electric vehicle) and a vehicle that can be powered by an electric motor that draws electricity from a battery and by an internal combustion engine (plug-in hybrid electric vehicle).

***Electrical Power Control Act, 1994 ("EPCA")*:** The act which regulates the electrical power resources of Newfoundland and Labrador.[1]

Electrification: Decarbonization that results in replacing processes or technologies that use fossil fuels with an electrically-powered equivalent that has a lower carbon intensity (e.g., through being powered partially or completely by renewable energy resources).

Emergency Operating Procedure ("EOP"): A procedure that includes a number of possible mitigating actions that can be enacted by the system operator, as required, to provide system relief.

Environmental Assessment ("EA"): A process to identify, predict and evaluate the potential environmental effects of a proposed project. This process happens before decisions about a proposed project are made.

Equivalent Forced Outage Rate ("EqFOR"): A measure of the probability that a generating unit will not be available due to forced outages or forced deratings.

Equivalent Forced Outage Rate Demand ("$EqFOR_d$"): A metric that measures the percentage of time that the LIL bipole is unable to deliver its maximum continuous rating to the Island due to bipole forced outages, bipole derates, derates due to unplanned monopole outages, or derates due to overlapping

[1] *Electrical Power Control Act, 1994, 1994* c E-5.1, <https://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm>

monopole outages (effectively creating a bipole outage). The effect of bipole derates and unplanned monopole outages is converted to equivalent bipole outage time for the purposes of calculating FOR.

Expected Unserved Energy ("EUE"): A measure of the amount of customer demand not served due to generation shortfalls.

Exploits Generation System: The Star Lake, Buchans, Grand Falls and Bishop's Falls Generating Stations and associated assets.

Firm Capacity: The amount of generation capacity available for production or transmission expected to be available at the annual peak when the unit is fully operational.

Firm Demand: That portion of the demand that a power supplier is obligated to provide, except when system reliability is threatened or during emergency conditions.

Firm Energy: Firm energy refers to the actual energy guaranteed to be available to meet customer requirements on an annual basis.

Firm Imports and Exports: A contract for the import or export of capacity or energy guaranteed to be available at a given time.

First Contingency: The first contingency is the unexpected failure or outage of a system's largest component, such as a generator or transmission line.

Forced Outage: (1) The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. (2) The condition in which the equipment is unavailable due to unanticipated failure.

Forced Outage Rate ("FOR"): The hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.

Fossil Fuel: The engineering design for a capital project. FEED work commences with the project brief at the start of a project through to the visualization, conceptualization and definition stages and involves translating the project into a conceptual design and then a basic design.

Frazil Ice: Soft or amorphous ice formed by the accumulations of ice crystals in water that is too turbulent to freeze solid. This type of ice accumulates at plant intakes limiting the area in which water can pass through, impacting the amount of water that can be drawn into the plant and, thereby, reducing the generating unit capability.

Front-End Engineering and Design ("FEED"): The engineering design for a capital project. FEED work commences with the project brief at the start of a project through to the visualization, conceptualization and definition stages and involves translating the project into a conceptual design and then a basic design.

Front-of-the-Meter ("FTM"): Systems that interact with the central power grid, including generation facilities, utility-sized energy storage facilities, and transmission and distribution lines.

Future Period: The period beyond 2030 (the Bridging Period).

G7 Nations: An informal grouping of the world's most advanced economies, including Canada, United Kingdom, United States, Germany, Italy, France, and Japan.

Galloping: High-amplitude, low-frequency oscillation of overland power lines due to wind; it can be caused by specific wind conditions and is sometimes observed on lines with small amounts of icing.

Gas Turbine (also known as combustion turbine) ("GT"): A fuel-fired combustion engine that can convert natural gas or other liquid fuels to mechanical energy. This energy then drives a generator that produces electrical energy. To generate electricity, the gas turbine heats a mixture of air and fuel at very high temperatures, causing the turbine blades to spin. The spinning turbine drives a generator that converts the energy into electricity.

Generator Step-Up Transformer ("GSU"): Takes the voltage from the generator voltage level up to the suitable transmission voltage level.

Gigajoule ("GJ"): A unit of energy for comparing the amount and cost of heat energy provided by different types of energy.

Gigawatt ("GW"): One thousand megawatts (1,000 MW) or, one million kilowatts (1,000,000 kW) or one billion watts (1,000,000,000 watts) of electric power.

Gigawatt Hours("GWh"): One million kilowatt-hours (1,000,000 kWh) of electric energy.

Greenhouse Gas ("GHG"): Any gas that absorbs infrared radiation in the atmosphere. The principal GHGs are carbon dioxide, methane, nitrous oxide, chlorofluorocarbons, halocarbons, and water vapour.

Grey Market: The trade of a commodity through distribution channels that are not authorized by the original manufacturer or trade mark proprietor.

Grid-Scale: Indicates the size and capacity of energy storage and generation facilities.

Gross Domestic Product ("GDP"): GDP is the total unduplicated value of the goods and services produced in the economic territory of a country or region during a given period.

Heat Recovery Steam Generator ("HRSG"): An energy recovery heat exchanger that recovers heat from a hot gas stream, such as a combustion turbine or other waste gas stream. It produces steam that can be used in a process (cogeneration) or used to drive a steam turbine (combined cycle).

Heat Recovery Ventilator ("HRV"): A ventilation device that helps make your home healthier, cleaner, and more comfortable by continuously replacing stale indoor air with fresh outdoor air.

High-Voltage Direct Current ("HVdc"): High voltage transmission system using direct current as opposed to the more common alternating current to transmit large quantities of power over long distances.

Hydroelectric Generation: Production of electricity by using turbines propelled by falling water and connected to a generator.

Industrial Customer: Any entity purchasing power, other than a retailer, supplied from the bulk transmission system at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the entity and which has entered into a contract with Hydro for the purchase of power and energy.

Industrial Load: The requirements for the Industrial customers directly served by Hydro.

In-Service: In operation and/or energized.

Interruptible Load: Interruptible load is a load, typically commercial or industrial, that can be interrupted in the event of a capacity deficiency in the supplying system.

Integrated Resource Plan ("IRP"): A planning process that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications.

International Association for Public Participation ("IAP2"): An international association of members who seek to promote and improve the practice of public participation / public engagement in relation to individuals, governments, institutions, and other entities that affect the public interest in nations throughout the world.

Intermittent Supply Resource: The balancing of supply-side and demand-side alternatives to meet energy needs at least cost.

Island: The island portion of the province of Newfoundland and Labrador.

Island Interconnected System ("IIS"): The interconnected portion of the island's electrical system. It is characterized by large hydroelectric generation capability located off the Avalon Peninsula, the Holyrood Thermal Generating Station on the Avalon Peninsula, and the bulk 230 kV transmission system extending from Stephenville in the west to St. John's in the east. The Island Interconnected System is interconnected to the Labrador Interconnected System via the Labrador-island Link ("LIL"). The Island Interconnected System is also connected to the North American grid via the Maritime Link.

Kilotonne ("kt"): A metric unit equivalent to one thousand tonnes (1,000 t), or 1 million kilograms (1,000,000 kg).

Kilovolt ("kV"): One thousand Volts.

Kilowatt ("kW"): A unit of electrical power equal to one thousand watts (1,000 W).

Kilowatt-Hour ("kWh"): A unit of electrical energy, which is equivalent to one kilowatt (1 kW) of power used for one hour. One kilowatt-hour (1 kWh) is equal to one thousand watt-hours (1,000 Wh).

Labrador Interconnected System: The interconnected portions of Labrador's electrical system form the Labrador Interconnected System. It is characterized by supply at Churchill Falls (provided by TwinCo Block and Recapture Energy), radial transmission to the two major load centres in Labrador East and Labrador West, and the Labrador Transmission Assets ("LTA") connecting Churchill Falls to Muskrat Falls. The Labrador Interconnected System is connected to the Island Interconnected System via the LIL. The Labrador Interconnected System is also connected to the North American grid via the 735 kV ac transmission lines from Churchill Falls to Quebec.

Labrador-Island Link ("LIL"): A 900 MW high voltage dc transmission line designed to deliver power from the Muskrat Falls Generating Station to Soldiers Pond Terminal Station on the Avalon Peninsula.

Labrador-Island Link Power Demand Override: Power Demand Override is a Special Protection Scheme of the LIL that activates following certain contingencies on the Maritime Link and in the Nova Scotia Power System.

Level 2 Schedule: A Level 2 schedule is the first level of scheduled detail where logical task relationships may be shown. It often includes a breakout of the various disciplines responsible for the activities in each phase, the critical engineering and procurement activities, and the major elements of construction by work area.

Load: The amount of electric power delivered or required at any specific point(s) on a system. The requirement originates from the energy-consuming equipment of the consumers.

Load Curtailment: Removal of pre-selected customer demand from a power system, as a result of the occurrence of an abnormal condition, to maintain the integrity of the system and minimize overall customer outages.

Load Forecast: The projected energy and demand requirements for the electrical system. The load forecast process entails translating a long-term economic and energy price forecast for the Province into corresponding electric demand and energy requirements for the electric power systems. Hydro predicts future load requirements for the Island Interconnected System primarily through econometric modelling techniques and large industrial customer input. Future load requirements for the Labrador Interconnected system are primarily through historical trend analysis and large industrial customer input.

Load Forecast Uncertainty: A multiplier representing the potential variance in annual peak demands. Its development is based on a distribution of expected values of load based upon an analysis of the weather sensitivity of peak loads.

Losses: The amount of energy lost during the generation, transmission, and distribution of electricity, including plant and unaccounted-for use.

Loss of Load: Loss of load refers to instances where some system load is not served, firm commitments are not met, or minimum operational reserve limits are violated.

Loss of Load Expectation ("LOLE"): The expected number of days each year where available generation capacity is insufficient to serve the daily peak demand.

Loss of Load Hours ("LOLH"): Loss of Load Hours is the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period instead of using only the daily peak in the LOLE calculation.

Loss of Load Probability ("LOLP"): The probability of system daily peak or hourly demand exceeding available generating capability in a given study period.

Maritime Link: A high voltage dc transmission line connecting Newfoundland and Nova Scotia.

Maritime Link Emergency Power Control: A special protection system of the Maritime Link that activates following certain contingencies on the LIL and Island Interconnected System as well as the Nova Scotia Power System.

Marginal Cost of Capacity: The Marginal Cost of Capacity is the incremental costs to serve an extra kilowatt of peak load including the cost of generation and operating reserves.

Maximum Continuous Rating ("MCR"): The maximum continuous rating is defined as the maximum output in MW that a generating station is capable of producing continuously under normal operating conditions over a year.

Megajoule ("MJ"): A unit of energy for comparing the amount and cost of heat energy provided by different types of energy.

Megatonne ("Mt"): A metric unit equivalent to one million tonnes (1,000,000 t), or 1 billion kilograms (1,000,000,000 kg).

Megavolt-Amperes ("MVA"): The unit used to measure the apparent power in a circuit

Megawatt ("MW"): A unit of electrical power equal to one million watts (1,000,000 W) or one thousand kilowatts (1,000 kW).

Megawatt Hour ("MWh"): One million watt-hours (1,000,000 Wh) of electric energy. A unit of electrical energy which equals one megawatt (1 MW) of power used for one hour.

Microclimates: A microclimate is the climate of a very small or restricted area, especially when this differs from the climate of the surrounding area. For the LIL, these are isolated areas along the line where weather may differ substantially from the general weather that was expected and included in the line's design.

Monte Carlo Analysis: A mathematical technique that generates random variables for modelling risk or uncertainty of a certain system.

N-1 Redundancy ("N-1"): The capacity to support full system load with the largest generating unit out of service.

N-2 Redundancy ("N-2"): The capacity to support full system load with the two largest generating units out of service.

Net Metering: Allows utility customers with small-scale generating facilities to generate power from renewable sources for their own consumption, and to feed power into the distribution system during periods when they generate excess power and draw power from the grid when their generation does not fully meet their needs.

Net Present Value ("NPV"): The difference between the present value of benefits and the present value of costs.

***Network Additions Policy – Labrador Interconnected System ("NAP')*:** Newfoundland and Labrador Hydro (2020). Network Additions Policy – Labrador Interconnected System.[2]

Newfoundland and Labrador Interconnected System: The Island Interconnected System and the Labrador Interconnected System combine to form the Newfoundland and Labrador Interconnected System.

Newfoundland and Labrador System Operator ("NLSO"): Hydro acting in its capacity as the Newfoundland and Labrador Systems Operator, being the systems operation department of Hydro, responsible for the safe and reliable operation of the Bulk Electric System, or a functionally separate division of Hydro performing this function, and includes its successors and permitted assigns.

Non-Dispatchable Generation: Generation that cannot be dispatched by the System Operator and/ or cannot be counted on at specific times is non-dispatchable. Examples are wind and solar because the energy source is not always available.

Non-Dispatachable Resource: An energy resource, such as wind power, that can not be used on demand and dispatched as per system needs.

Non-Emitting Electricity: Electricity produced in a manner that does not directly release any greenhouse gases as a result of fuel combustion. Non-emitting generation sources include hydro, wind, solar, nuclear, etc.

Non-Firm Imports and Exports: A contract for the import or export of capacity or energy which is not guaranteed to be available at a given time.

Non-Spinning Reserve: (1) That generating reserve not connected to the system but capable of serving demand within a specified time. (2) Interruptible load that can be removed from the system in a specified time.

Non-Utility Generator ("NUG"): An electricity producer that does not have a mandate or obligation to supply electricity to the public.

[2] https://nlhydro.com/wp-content/uploads/2021/03/Network-Additions-Policy.pdf

Normalized Expected Unserved Energy ("NEUE"): A measure of the amount of customer demand not served due to generation shortfalls divided by the total system energy.

North American Electric Reliability Corporation ("NERC"): A non-profit, self-regulating organization whose objective is to ensure adequate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel.

Northeast Power Coordinating Council, Inc. ("NPCC"): NPCC is a regional entity division which operates under a delegation agreement with the North American Electric Reliability Corporation (NERC). Members include the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec, and the Maritime provinces of New Brunswick and Nova Scotia.

Nova Scotia Block: A firm commitment of 980 GWh, to be supplied annually from the Muskrat Falls Hydroelectric Generating Station on peak.

Off-Peak: Period of relatively low demand on a generating system.

On-Peak: Period of relatively high demand on a generating system.

Ontario Energy Board Act, 1998: *Ontario Energy Board Act, 1998, SO 1998, c 15.*

Operational Reserve: A system requirement where the system requires the ability to withstand the loss of the single largest resource while maintaining an additional reserve.

Outage: The state of a component when it is not available to perform its intended function due to some event directly associated with that component.

P50 Forecast: A forecast in which the actual peak demand is expected to be below the forecast number 50% of the time and above 50 percent of the time (i.e., the average forecast.)

P90 Forecast: A forecast in which the actual peak demand is expected to be below the forecast number 90% of the time and above 10 percent of the time (i.e., there is a 10% chance of the actual peak demand exceeding the forecast peak demand).

Peaking: Meeting peak system load.

Peaking Unit: A generating unit used to meet the portion of peak load that cannot be met by baseload units. Generally, these are higher energy cost units, such as combustion turbines.

Peak Capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.

Peak Demand: The highest level of electricity consumption that the utility has to supply to the system at a given time. Peak demand on the electrical system is measured in megawatts (MW) and occurs in the winter on the Island Interconnected System.

Penstock: A conduit that conveys water from the intake to the turbine.

Planning Horizon: The period 2025 to 2034.

Planning Reserve Margin: The reserve margin at which the system reliability is at criteria. It is used as a reliability metric to evaluate the system's resource adequacy for expansion planning.

PLEXOS: Simulation software with modelling capabilities across electric, gas, and water systems, allowing for the optimization of interdependent energy markets.

PMBOK: Project Management Institute, Inc. A Guide to the Project Management Body of Knowledge (PMBOK Guide) and the Standard for Project Management, 7th ed., Project Management Institute, Inc., Newton Square, PA, 2021.

Powerhouse: A structure that contains the turbine and generator of a power project.

Power System Simulator for Engineering ("PSSE"): A software tool used by power system engineers to simulate electrical power transmission networks in steady-state conditions as well as over timescales of a few seconds to tens of seconds.

Power Purchase Agreement ("PPA"): A bilateral wholesale or retail power contract for the purchase of capacity and/or energy from a third party.

Probabilistic Analysis: Probabilistic analysis simulation requires completion of several simulations using randomly sampled variables like outage profiles, wind generation and weather related load uncertainty to determine system reliability. When compared to deterministic analysis, probabilistic analysis better incorporates the random behavior of system states as well as the operational restrictions of the system. See Monte Carlo Analysis.

Program Administrator Cost Test ("PAC Test"): A test that measures the net costs of a program as a resource option based on the costs incurred by the Program Administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC test, but costs are defined more narrowly.

Public Utilities Act ("Act"): *Public Utilities Act, RSNL 1990*, c P-47.

Pugh Concept Selection Process or Pugh Method ("PUGH Analysis"): A decision matrix used to evaluate and prioritize alternatives or solutions based on established and weighted evaluation criteria.

Punchlist: Punchlist items are a list of incomplete scope and/or deficiencies agreed between Contractor offering the equipment, system or part system and the RFO receiving the equipment, system or part system.

Rated Capacity: A function of various environmental factors including ambient temperature.

Recapture Block: A source of 300 MW of capacity at a 90% monthly load factor available at a defined point near the Quèbec to Labrador border.

Reference Case: A forecast of firm electric power demand and energy requirements developed by Hydro to assess the impacts of customer, demographic, and economic factors on the future electricity load requirements for the Island Interconnected System.

Regulating Reserve: Unlike other reserves that are used in response to contingencies (i.e., operating reserves), regulating reserves are used throughout an operating hour to maintain system frequency in response to fluctuations in loads and in output from variable generation resources.

Reliability: The extent to which equipment, systems and facilities perform as originally intended. This encompasses the confidence in the soundness or integrity of the equipment based on forced outage and derating experience, maintenance effort, the output of the equipment in terms of efficiency and capacity, unit availability and the remaining service life.

Remedial Action Scheme ("RAS"): A scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a system(s).

Reserve: The extra generating capability that an electric utility needs, above and beyond the highest demand level it is required to supply to meet its user's needs.

Reserve Capacity: The extra generating capability that an electric utility needs, above and beyond the highest demand level it is required to supply to meet its user's needs.

Reserve Margin: The percentage by which available capacity is expected to exceed forecasted peak demand across the system. Reserves must be available in case resources are unexpectedly unavailable at the time of peak demand or system demand exceeds the forecast peak.

Return Period: An estimate of the likelihood of a climatological event to occur. It is usually used for risk analysis (e.g., to design structures to withstand an event with a certain return period). Also referred to as recurrence interval.

Run-of-River: Hydroelectric generating facilities that depend chiefly on the flow of a stream as it occurs for generation, as opposed to a storage project, that has space available to store water from one season to another. Some run-of-the-river projects have a limited storage capacity (pondage) that permits them to regulate streamflow on a daily or weekly basis.

Service Life: The expected useful lifespan of a generating unit.

Sensitivities: Cases developed to study the impact of change in variables on resource planning analysis. These sensitivities include addition of large loads in Labrador, and the uncertainty in load projections associated with future customer rates.

Simple Combustion Turbine ("SCCT"): A type of combustion turbine typically used in power generation, aviation (for jet engines), and oil and gas industries (for electricity generation and mechanical drives).

Slow Decarbonization Island Interconnected System Load Forecast ("Slow Decarbonization"): A forecast developed to reflect the range of forecasted Island Interconnected System load requirements that assumes a lower-than-expected load.

Special Protection Scheme: The means by which circuit loadings, voltage or frequency can be controlled after an event on the power system which might otherwise cause an overload of transmission equipment (e.g., circuit or transformer).

Spinning Reserve: Unloaded generation that is synchronized and ready to serve additional demand. Also referred to as synchronized reserve.

Standby Generation: Generation that is available, as needed, to supplement a utility system or another utility. The generation is not regularly used.

Static Synchronous Compensator ("STATCOM"): A fast-acting device capable of providing or absorbing reactive current and thereby regulating the voltage at the point of connection to a power grid.

Storage Capacity: The amount of energy an energy storage device or system can store.

Strategic Supplier Partnership: A relationship between an owner company and a supplier that is more than transactional and involves mutual benefits, shared risks and rewards, and a long-term collaboration plan.

Study Period: 2024 through 2034.

Supplemental Energy: A firm energy commitment to supply energy to Nova Scotia during the first five years of production at the Muskrat Falls Generating Station as part of the Amended and Restated Energy and Capacity Agreement.

Synchronized Reserve: Refer to Spinning Reserve.

Synchronous Condenser: A specialized synchronous machine whose shaft is not attached to anything, but spins freely. Its purpose is not to convert mechanical power to electrical power like synchronous generators but rather to assist in voltage control of the transmission system to which it is connected.

System Operator: Entity entrusted with the operation of the control center and the responsibility to monitor and control the electric system in real time.

Terminal Station: An electrical station containing equipment with a voltage of at least 66 kV, which is used to change the voltage level or provide a switching point for a number of transmission lines.

Thermal Overload: A thermal overload occurs when power flow through a line exceeds its rated capacity.

Time-of-use-Rates ("TOU Rates"): An option for customers that offers electricity rates that vary throughout the day based on load patterns; with the highest rates during peak hours and lowest rates during off-peak hours.

Transmission Constraint: A limitation on one or more transmission elements that may be reached during normal or contingency system operations.

Transmission Line ("TL"): A set of conductors, insulators, supporting structures, and associated equipment used to move large quantities of power at high voltage, usually over long distances between a generating or receiving point and major substations or delivery points.

Terrawatt ("TW"): A unit of electrical power equal to one thousand megawatts (1,000 MW) or, one million kilowatts (1,000,000 kW) or one billion watts (1,000,000,000 watts) of electric power.

Terrawatt Hours ("TWh"): One thousand gigawatt hours (1,000 GWh).

Total Resource Cost Test ("TRC Test"): A test that measures the net costs of the program as a resource option based on the total costs of the program, including both the participants and the utility's costs.

Turbine: The part of a generating unit usually consisting of a series of curved vanes or blades on a central spindle, which is spun by the force of water, steam or hot gas to drive an electric generator. Turbines convert the kinetic energy of such fluids to mechanical energy through the principles of impulse and reaction or a measure of the two.

TwinCo Block: A firm 225 MW block of power and energy, capable of supplying 1,971 GWh per year for use in Labrador West.

Under Frequency Load Shedding ("UFLS"): the automatic or manual actions required to shed system load when the system frequency falls below defined acceptable parameters, to bring the system back in balance.

Useful Life: The period of time over which an asset is expected to be available for Hydro.

Utilization Forced Outage Probability ("UFOP"): is the probability that a generating unit will not be available due to forced outages when there is demand on the unit to generate.

Weather-Adjusted Peak Demand: Weather adjustment is a process that adjusts actual peak outcomes to what would have happened under normal or average weather conditions. The weather adjustment is derived from Hydro's Newfoundland Power native peak demand model and the results are extrapolated to adjust Hydro's Island Rural peak.

Vista Decision Support System ("Vista DSS"): A software program used by Hydro to provide medium- to long-term water storage and energy-generation management that guides water operations, hydraulic and thermal generation, and energy transactions.

Voltage Support: The application of synchronous generators, synchronous condensers, capacitor banks and other reactive power sources to maintain the transmission system voltage level within acceptable limits as load on the system increases.

Watt ("W"): The scientific unit of electric power; a rate of doing work at one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts. One horse power is 746 watts.

Watt-hour ("Wh"): One watt (1 W) of power expended for one hour.

Weight Average Cost of Capital ("WACC"): A financial ratio that measures a company's financing costs, weighing equity and debt proportionally to its percentage of the total capital structure.

Scenario Summary Tables

Scenario Summary Tables

Scenario	Description	Capacity Build				Energy Build					NPV[1] ($Billions)	Max. Emissions[2] (kt)
		2031	2032	2033	2034	2030	2031	2032	2033	2034		
1	Unrestricted	BDE Unit 8 2 CTs						1 Wind		2 x Wind	3.9	48
1A	Fixed Wind Profile	BDE Unit 8 1 CT 1 Battery		1 CT		2 Wind	2 Wind	1 Wind			4.8	48
1AB40	Fixed Wind, Batteries ELCC 40%	BDE Unit 8 1 CT CAT Unit 3			1 CT	2 Wind	2 Wind	1 Wind			4.8	48
1AB80	Fixed Wind, Batteries ELCC 80%	BDE Unit 8 4 Batteries		1 Battery	1 Battery	2 Wind	2 Wind	1 Wind			4.7	2
1AC	Fixed Wind, No Fuel Burnoff for CT	3 CTs				2 Wind	2 Wind	1 Wind			4.3	5
1AD	Fixed Wind, Hydro Capital Cost +50%	2 CTs 1 Battery		1 CT		2 Wind	2 Wind	1 Wind			5.0	71
1AE	Fixed Wind, No Batteries	BDE Unit 8 2 CTs				2 Wind	2 Wind	1 Wind			4.8	48
1AEC	Fixed Wind, No Batteries, No Fuel Burnoff for CT	3 CTs				2 Wind	2 Wind	1 Wind			4.3	5
1AEF	Fixed Wind, No Batteries, Limit CT to 150 MW	BDE Unit 8 1 CT CAT Unit 3			1 Proxy	2 Wind	2 Wind	1 Wind			5.8	35
1AEG	Fixed Wind, No Batteries, Fuel Cost +50%	BDE Unit 8 2 CTs				2 Wind	2 Wind	1 Wind			5.0	48
1AEH	Fixed Wind, No Batteries, CT Capital Cost +50%	BDE Unit 8 2 CTs				2 Wind	2 Wind	1 Wind			5.5	48
1AEI	Fixed Wind, No Batteries, NP CTs (75 MW)	BDE Unit 8 1 CT			CAT Unit 3	2 Wind	2 Wind	1 Wind			4.4[3]	25[4]

[1] Exclusive of transmission upgrade costs and market export opportunities
[2] Maximum emissions (kt) from 2031 onwards.
[3] Excludes the cost of Newfoundland Power's 75 MW CTs.
[4] Excluding the emissions of Newfoundland Power's 75 MW CTs.

Scenario	Description	Capacity Build				Energy Build					NPV[5]	Max. Emissions[6]
		2031	2032	2033	2034	2030	2031	2032	2033	2034	($Billions)	(kt)
4	Unrestricted	BDE Unit 8			1 CT		1 Wind	1 Wind	1 Wind		2.4	25
4A	Fixed Wind Profile	BDE Unit 8			1 Battery	1 Wind	3 Wind				2.8	2
4AB40	Fixed Wind, Batteries ELCC 40%	BDE Unit 8			1 CT	1 Wind	3 Wind				2.8	25
4AB80	Fixed Wind, Batteries ELCC 80%	BDE Unit 8			1 Battery	1 Wind	3 Wind				2.7	2
4AC	Fixed Wind, No Fuel Burnoff for CT	1 CT			1 CT	1 Wind	3 Wind				2.7	3
4AD	Fixed Wind, Hydro Capital Cost +50%	1 CT			1 CT	1 Wind	3 Wind				3.0	48
4AE	Fixed Wind, No Batteries	BDE Unit 8			1 CT	1 Wind	3 Wind				2.8	25
4AEC	Fixed Wind, No Batteries, No Fuel Burnoff for CT	1 CT			1 CT	1 Wind	3 Wind				2.7	3
4AEF	Fixed Wind, No Batteries, Limit CT to 150 MW	BDE Unit 8			1 CT	1 Wind	3 Wind				2.8	25
4AEG	Fixed Wind, No Batteries, Fuel Cost +50%	BDE Unit 8			1 CT	1 Wind	3 Wind				2.9	25
4AEH	Fixed Wind, No Batteries, CT Capital Cost +50%	BDE Unit 8			1 CT	1 Wind	3 Wind				3.00	25
4AEI	Fixed Wind, No Batteries, NP CTs (75 MW)	BDE Unit 8				1 Wind	3 Wind				2.4[7]	2[8]

[5] Exclusive of transmission upgrade costs and market export opportunities
[6] Maximum emissions (kt) from 2031 onwards.
[7] Excludes the cost of Newfoundland Power's 75 MW CTs.
[8] Excluding the emissions of Newfoundland Power's 75 MW CTs.

Scenario	Description	Capacity Build 2031	Capacity Build 2032	Capacity Build 2033	Capacity Build 2034	Energy Build 2030	Energy Build 2031	Energy Build 2032	Energy Build 2033	Energy Build 2034	NPV[1] ($Billions)	Max. Emissions[2] (kt)
1AEF	Reference Case LIL Bipole FOR 5% Planning Criteria 2.8 LOLH	BDE Unit 8 1 CT CAT Unit 3			1 Proxy	2 Wind	2 Wind	1 Wind			5.8	35
2AEF	Accelerated Decarbonization LIL Bipole FOR 5% Planning Criteria 2.8 LOLH	BDE Unit 8 1 CT CAT Unit 3 1 Proxy		1 Proxy	1 Proxy	3 Wind	2 Wind	1 Wind	1 Wind		8.9	54
3AEF	Slow Decarbonization LIL Bipole FOR 5% Planning Criteria 2.8 LOLH	BDE Unit 8 1 CT			CAT Unit 3	1 Wind	3 Wind				4.1	25
4AEF	Slow Decarbonization LIL Bipole FOR 1% Planning Criteria 2.8 LOLH	BDE Unit 8			1 x CT	1 Wind	3 Wind				2.8	25
5AEF	Accelerated Decarbonization LIL Bipole FOR 10% Planning Criteria 2.8 LOLH	BDE Unit 8 1 CT CAT Unit 3 2 Proxy		1 Proxy	2 Proxy	3 Wind	2 Wind	1 Wind	1 Wind		10.1	74
6AEF	Accelerated Decarbonization LIL Bipole FOR 1% Planning Criteria 2.8 LOLH	BDE Unit 8 Cat Unit 3		1 x CT		3 Wind	2 Wind	1 Wind	1 Wind		6.6	25
7AEF	Slow Decarbonization LIL Bipole FOR 5% Planning Criteria 0.1 LOLE	BDE Unit 8 1 CT CAT Unit 3 1 Proxy	1 Proxy		1 Proxy	1 Wind	3 Wind				6.4	55
8AEF	Reference Case LIL Provides no Capacity Benefit Planning Criteria 2.8 LOLH	BDE Unit 8 1 CT CAT Unit 3 3 Proxy		1 Proxy	1 Proxy	2 Wind	2 Wind	1 Wind			8.2	74

[9] Exclusive of transmission upgrade costs and market export opportunities.
[10] Maximum emissions (kt) from 2031 onwards.